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 #19-3
August 7, 2019 10:00 a.m. – 4:00 p.m. EST
August 8, 2019 8:30 a.m. – 2:00 p.m. EST
Hydro One South Tower 06 Boardroom
483 Bay Street
Toronto, Ontario Canada
Attire: Business Casual

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

Day 1 - RSC Business:
Guest Code: 649523881
Password: Ev9bpE3* (38927330 from phones)

Day 2 - DER Forum:
Guest Code: 643668616
Password: UyVe2M5? (89832650 from phones)

Day One RSC Business:

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated May 13, 2019
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 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 Regional Standard Processes Manual
5.3 New Proposed, Endorsed, and Non-Endorsed Implementation Guidance
5.4 FERC TPL-001-5 NOPR

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 2017-01 Modifications to BAL-003-1.1	1/17/19 (F)	1/17/19 (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	7/17/19 (F)	7/17/19 (A)
Project 2018-04 Modifications to PRC-024-2	7/26/19 (F)	5/31/19 (I)
Project 2019-01 Modifications to TPL-007-3	9/9/19 (F)	9/9/19 (I)
Project 2019-02 BES Cyber System Information Access Management	4/26/19 (F)	
Project 2019-03 Cyber Security Supply Chain Risks	8/1/19 (I)	
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final		

6.2 Ballot History (Since last RSC Meeting)

6.3 Comment Form History (Since last RSC Meeting)

7.0 NERC Drafting Team Nominations

7.1 Currently Posted Drafting Team Vacancies

7.1.1 None at this time

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)

7.2.1 None at this time

7.3 Solicitation for Informal Development Teams

7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

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

8.1 Current Activities:

8.1.1 PRC-006-NPCC-2 Automatic Underfrequency Load Shedding Standard status update.

9.0 NPCC Non-Standards

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

9.1 Items for Discussion:

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

(Status of RAS Implementation/Transition)

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

9.1.3 Directory Manual --- Cost Effective Revisions
RSC Review of Open Process Comments. (Posting Closed Feb. 18, 2019)

9.1.4 BOD Approved Corporate Goal:
(Cost Effective Pilot ---- Directory #4 and Directory#5)
Status of Open Process Posting.

9.1.5 Other Items

9.2 Items for Approval:

9.2.1 Directory Manual ----- RSC Approval
Repost Revised Directory Manual

9.3 Executive Tracking Summary

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 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

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

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

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

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 three new Lesson Learned issued since the last RSC meeting.

13.2 Alerts

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

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

14.0 Other Items of Interest

14.1 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

14.2 NPCC and ERO 2020 Business Plan and Budget Schedule

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2019 Meeting Date

February 13th-14th, Eversource, Boston MA
May 15th-16th, Saratoga NY
August 7th-8th, Hydro One Toronto Canada
October 16th-17th, Lewiston NY
December 5th, 2019 Montreal Canada (General Meeting)

Day Two DER Forum:

16.0 Distributed Energy Resources (DER) Forum Topics

16.1 DER, Approach to Regional Guidance and DER Impact Reporting
16.2 NERC SPIDER Working Group Presentation by Utility Services
16.3 Impacts of DERs in Ontario presentation by Mohab Elnashar from IESO
16.4 DER current state presentation by Nicolas Compas from Hydro Quebec
16.5 Inverter Based Resources presentation by NAGF
16.6 Hydro One DER Update presented by Adnan Akhtar
16.7 Duke Energy Project on DER presented by Adam Guinn
16.8 SunRun Presentation on DER by Ben Carron

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 #19-2
May 15, 2019 10:00 a.m. – 4:00 p.m. EST
May 16, 2019 8:30 a.m. – 12:00 p.m. EST
Hampton Inn & Suites Saratoga Springs Downtown Hotel
25 Lake Avenue
Saratoga Springs, New York
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)
Day 1 - RSC Business:
Guest Code: 648097035
Password: zSkhH@53 (97544153 from phones)

Day 2 - DER Forum:
Guest Code: 643553113
Password: rHt9Rd@6 (74897316 from phones)

Day One RSC Business:

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated July 3, 2018
NPCC Glossary of Terms, dated January 14, 2014

	Name	Organization	Sector (s)	Day(s)	Comment
1.	Guy Zito	Northeast Power Coordinating Council		1, 2	
2.	Gerry Dunbar	Northeast Power Coordinating Council		2	Via Webex
3.	Ruida Shu	Northeast Power Coordinating Council		1, 2	
4.	Juan Villar	FERC	Guest	1, 2	
5.	Michael Godbout	Hydro Quebec	2	1, 2	
6.	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1, 2	
7	Chris Overberg	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1, 2	
8.	Constantin Chitescu	Ontario Power Generation, Inc.	4	1, 2	
9.	David Lemstra	Ontario Power Generation, Inc.	Guest	1, 2	

10.	Payam Farahbakhsh	Hydro One Networks	1	1, 2	
11.	Ben Wu	Orange & Rockland Utilities, Inc.	3	2	
12.	David Burke	Orange & Rockland Utilities, Inc.	3	1, 2	Via Webex
13.	Brian Robinson	Utility Services, Inc.	5	1, 2	
14.	Sean Bodkin	Dominion Resources Services	4	1	Via Phone
15.	Sean Lagan	IESO	Guest	1, 2	
16.	Salvatore Spagnolo	NYPA	4	1, 2	
17.	Randy Crissman	NYPA	Guest	1, 2	
18.	Greg Campoli	NYISO	2	1, 2	
19.	Jim Grant	NYISO	2	1, 2	
20.	James Pigeon	NYISO	Guest	2	
21.	Mike Jones	National Grid	3	1, 2	
22.	David Kiguel	Independent	7	1, 2	Via Webex
23.	Joel Charlebois	AESI	7	1, 2	
24.	Quintin Lee	Eversource	1	1, 2	
25.	Kathleen Goodman	ISO-NE	2	1, 2	
26.	David Forest	ISO-NE	Guest	2	
27.	Bradley Marszalkowski	ISO-NE	Guest	2	
28.	Glen Smith	Entergy	4	1, 2	
29.	Vijay Puran	New York State Department of Public Service	6	1, 2	
30.	Jason Pause	New York State Department of Public Service	Guest	2	
31.	Michele Tondalo	UI	1	1, 2	
32.	Laura Mcleod	NB Power	1	1, 2	Via Webex
33.	Wayne Sipperly	NARUC	Guest	2	

34.	George Smith	~~Independent~~NYSRC	Guest	2	
35.	Evangelos Farantatos	EPRI	Guest	2	Via Webex

Introductions and Chair's Remarks

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

Agenda Items:

1.0 Review of Agenda
Guy Zito reviewed the meeting agenda with the RSC group and he moved the meeting agenda item 16.5 to 16.1 for introduction of DER forum.

2.0 RSC Meeting Minutes
Approval of Minutes—no additional revisions were made to the draft RSC meeting minutes of 2-13-18
Herb Schrayshuen made the motion for approval.
Jim Grant 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 and made no additional changes.

3.2 NERC Project Tracking Spreadsheet
Guy Zito and Ruida Shu provided a brief update on the NERC Project Tracking Spreadsheet.

4.0 Open Action Items

4.1 Open Action Items List
Item 4.1 Regional Standards Process Manual~~RSPM~~:
There aren't any major changes, Mike Jones suggested that it is not necessary for NPCC to send a notification to NERC on every comment ~~and ballot~~ posting.
Action Item:
Guy Zito and Ruida Shu will review the draft redline RSPM from 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 EPRI Report on HEMP
Guy Zito gave a presentation on HEMP.
HEMP is High altitude Electromagnetic Pulse and it is defined in the presentation.

EPRI report provided high impact low frequency risk and concluded with three different events E1, E2 and E3.
NERC formed a task force to address the President's order in regards to the HEMP. The first conference call will be on May 20, 2019.
The initial conference call is not open to public.

5.3 NERC SPIDER (System Planning Impact of Distributed Energy Resources) Work Group

A draft Standards Authorization Request (SAR) has been prepared for MOD-032 Data for Power System Modeling and Analysis. The draft SAR was sent to the NERC Planning Committee for their review. DER information is needed to do UFLS studies/reliability studies. ~~At this time, there is no perfect solution for this.~~

NPCC BOD directed NPCC to create a guidance document for DER ~~to connect onto the grid~~.

The goal is to collect the data so reliability studies can be done appropriately.

5.4 FERC Matters

Guy Zito provided a presentation summarizing the recent FERC orders and FERC NOPRs~~S~~ of interest.

5.5 NATF EPRI-NERC Transmission Resilience Summit

Guy Zito provided a presentation on the Transmission Resilience Summit.
He summarized four outcome-based abilities of resilience (framework) are 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.

5.6 CIP-013-1 Vendor Certification Issue

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 2017-01 Modifications to BAL-003-1.1	1/17/19 (F)	1/17/19 (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	12/18/18 (I)	4/29/19 (F)
Project 2017-07 Standards Alignment with Registration	3/2/18 (F)	
Project 2018-03 Standards Efficiency Review Retirements	4/12/19 (F)	5/2/19 (F)

Project 2018-04 Modifications to PRC-024-2	5/31/19 (F)	5/31/19 (I)
Project 2019-01 Modifications to TPL-007-3	3/26/19 (I)	
Project 2019-02 BES Cyber System Information Access Management	4/26/19 (F)	
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final		

Project 2018-04 Modifications to PRC-024-2:
Mat Bunch called in at 1:00PM.
It was posted on April 17, 2019 and the ballot will start next week.
Requirement R1 and R2 modified to specify that a generating resource may neither trip NOR enter momentary cessation inside the No Trip Zone.
The drafting team clarified the confusion in regards to tripping or entering momentary cessation outside the No Trip Zone, the area outside the boundary is now labeled as a "May Trip Zone".
Facilities Section added that explicitly lists protective functions for specific equipment.

-Plant Auxiliary Equipment is not included as an applicable facility.

Applicability Section: Added Transmission Owners that own a BES generator step-up (GSU) transformer or collector transformer and apply frequency or voltage protective functions.

-Specific that voltage and frequency protection should be applied to both generator step-up (GSU) and collector transformers

-Addresses a potential reliability gap identified by the standard drafting team. Some TO own GSU or collector transformers, yet are not currently in scope PRC-024.

~~Inclusions:~~ Not all TOs are applicable and only those specific TOs that own a GSU or collector transformer and apply protection listed in the facilities section are now in scope of PRC-024.
"Point of interconnection" is removed from the requirement language.
The ballot will close on May 31, 2019.
First week of June 2019 will have multiple conference calls to address comments.
The next drafting team meeting will be held on June 18-20, 2019 at Montreal Quebec.

Project 2015-09 Establish and Communicate System Operating Limits:
Dean LaForest called in at 1:45PM.
The drafting team has been working on the comments from the last posting.
One of the issues is some of the drafting team members thinks that FAC-015 should be put into a TPL standard.
FAC-011 and FAC-014 is in progressed to be revised and they have overall consensus. FAC-015 is still being reviewed by the drafting team.
The drafting team will leave CIP-002 as it is for the time being, it will be part of the second phase of the drafting team.
The drafting team members will pull together SOL exceedance data to show FERC representative in the next a few weeks at the next SDT meeting.

Project 2018-03 Standard Efficiency Review Retirements:
There are 84 retirement requirements for Phase 1 of the SER project.

A SAR for Phase 2 of the SER project will be posted approximately two months from now. The Standard Alignment with Registration project is on hold, waiting to see the SAR for Phase 2 of the SER project.
~~Greg Campoli~~Michael Puscas from ISO-NE will have a presentation at the NPCC workshop in Mystic CT on May 22-23, 2019 regarding the standard efficiency concepts that have been developed: Evidence Retention Overhaul, Prototype Standard, Move Requirements to Guidance. Consolidate and Simplify Training Requirements, Consolidate Information/Data Exchange Requirements, Relocate Competency-based Requirements to the Certification Program /CMEP Controls Review.~~.~~

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 Standard status update.

Ruida Shu reviewed the status of PRC-006-NPCC-2 with the RSC members.

NPCC BOD approved the PRC-006-NPCC-2 Automatic Underfrequency Load Shedding Regional Standard.

The standard is sent to NERC on May 2 and 3, 2019. It is posted for comments on process only from May 8, 2019 to June 21, 2019.

After the comment period ends the standard will be sent to NERC BOT for approval at their August 14-15, 2019 meeting.

NPCC Compliance Staff is drafting the Reliability Standard Audit Worksheet (RSAW) for PRC-006-NPCC-2.

9.0 NPCC Non-Standards

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

9.1 Items for Discussion:

9.1.1 Directory#7 *SPS* and NPCC Glossary term SPS (Status of RAS Implementation/Transition)

The Task Force on Coordination of Planning (TFCP) is coordinating the regional transition to Remedial Action Scheme (RAS).

The TFCP has proposed revisions to Directory#7 Appendix B which governs the regional review process for new, revised or retired Special Protection Systems (SPS). The revisions conform the regional review process to the requirements of PRC -012-2 Remedial Action Schemes (RAS).

The proposed revisions to Appendix B have been provided to other NPCC Task Forces for review and comment.

The revised Appendix B will be included in a draft of Directory#7 when D#7 is posted to the Open Process upon completion of the current TFSP review.

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

The TFCP and the CP-11 Working Group have completed a comprehensive review of NPCC document A-10 *Classification of Bulk Power System Elements.*

In accordance with the TFCP Scope of Work the CP-11 Working Group considered existing and alternative methodologies to 1) identify critical facilities for the applicability of NPCC criteria 2) simplify the methodology 3) improve consistency across Areas in application and outcomes of the methodology.

The Reliability Coordinating Committee (RCC) approved the CP-11 recommendations as presented in the Phase 2 Final Report on the A-10 Review on December 4, 2018.

Subsequent to RCC approval the recommendations contained in the Phase 2 Final Report have been incorporated into a revised version of the A-10. The revisions to the methodology are consistent with the recommendations contained in the Phase 2 Final Report and include modifications to the existing performance based test which incorporate improvements to the base case set-up and the utilization of specific performance requirements (instability, cascading and net L/O Source or L/O Load greater than an Area’s threshold) to evaluate testing outcomes.

An element exclusion process for applicability to Directory#1 *Design and Operation of the Bulk Power System* has also been proposed.

The exclusion process consists of both automatic and study based exclusions and recognizes that once protection system redundancy as required by Directory #4

System Protection Criteria has been achieved, there may not be a need to categorize every element as critical for Directory#1 applicability.

The draft revised A-10 is currently posted to the Open Process for 45 days through July 1, 2019.

9.1.3 Directory Manual --- Cost Effective Revisions
RSC Review of Open Process Comments. (Posting Closed Feb. 18, 2019)

The RSC proposed revisions to the Directory Manual which will incorporate a cost effective process within the Manual.

The revised Manual including cost effective revisions was posted to the Open Process through Feb. 18, 2019.

RSC consideration of comments is pending the completion of the cost effective pilot on Directories #4 and #5. (see below).

9.1.4 BOD Approved Corporate Goal:
(Cost Effective Pilot ---- Directory #4 and Directory#5)
Status of Open Process Posting.

Directory #4 *System Protection Criteria* and Directory #5 *Reserve* were reviewed by the TFSP and TFCO respectively as part of the normal review cycle of both documents.

The revised documents were posted to the Open Process along with a cost effective survey designed to solicit Member comment on the cost effectiveness of the criteria.

Each Task Force will incorporate survey responses into the permanent record of the documents review.

The results of the survey will also inform a repeatable process governing all future Directory reviews to be incorporated into the Directory Manual.

9.2 Executive Tracking Summary

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 23rd – Call	February 20th – Call	March 20th – Austin TX (Austin Energy)
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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

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

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

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

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 two 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) 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

14.2 NPCC and ERO 2020 Business Plan and Budget Schedule

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2019 Meeting Dates

February 13th-14th, Eversource, Boston MA
May 15th-16th, Saratoga NY
August 7th-8th, Hydro One Toronto Canada
October 16th-17th, Lewiston NY
December 5th, 2019 Montreal Canada (General Meeting)

Day Two DER Forum:

Participants via Webex:

	Name	Organization	Comment
1.	Brian Yung	National Grid	Via Webex
2.	Chelsea Zhu	National Grid	Via Webex
3.	Dan Kopin	Utility Services	Via Webex

4.	David Gordon	MMWEC	Via Webex
5.	Dennis Bergeron	Maine Government	Via Webex
6.	Hantz Presume	VELCO	Via Webex
7.	Hao Fu	PSEG	Via Webex
8.	Haretha Alao		Via Webex
9.	Joe Farella	National Grid	Via Webex
10.	Mark Domino	National Grid	Via Webex
11.	Michael Lombardi	NPCC	Via Webex
12.	Michael Ridolfino	Central Hudson	Via Webex
13.	Nazila Rajaei	Hydro One	Via Webex
14.	Nick Parrotta	PLM	Via Webex
15.	Per-Anders Lof	National Grid	Via Webex
16.	Qinling Zheng		Via Webex
17.	Rick Kowalski	ISO-NE	Via Webex
18.	Alex Rost	ISO-NE	Via Webex
19.	Kannan Sreenivasachar	ISO-NE	Via Webex
20.	Nithya Reddy-Tada	ISO-NE	Via Webex
21.	Rodolfo Vega	ISO-NE	Via Webex
22.	Roger Clayton		Via Webex
23.	Steven Judd		Via Webex
24.	Tracy MacNicoll	Utility Services	Via Webex
25.	Tom Reece		Via Webex
26.	Yves Albert	NB Power	Via Webex

16.0 Distributed Energy Resources (DER) Forum Topics

16.1 DER, Approach to Regional Guidance

Mr. Zito welcomed DER forum participants and provided background information on the purpose of the forum.

Mr. Zito explained that the NPCC Board of Directors (BOD) has identified a corporate goal for the Regional Standards Committee (RSC) to develop a coordinated regional approach for reliability guidelines for Distributed Energy Resources (DER). Additionally a DER forum under the RSC will be established to expand coordination of DER's with various agencies including FERC, NERC, and NARUC.

Mr. Zito described the framework of the RSC DER forum which is envisioned to be conducted on the second day of the RSC meeting and will provide a platform for the open discussion of issues, opportunities and information sharing,

Mr. Zito noted the opportunity for the development of an NPCC guidance DER document that will serve to promote important reliability as DER implementation continues to expand.

Mr. Zito explained that such a document would be voluntary, informational, and non-enforceable and will be developed using the NPCC Open Process.

Mr. Zito identified a number of existing DER related issues that are currently impacting the BES or have the potential to do so in the future.

Mr. Zito noted that some of these issues have informed the presentations that forum participants will receive today.

16.2 BPS Reliability Implications of High Levels of Inverter-Based Resources – EPRI's Transmission Operations & Planning R&D Overview

Mr. Evangelos Farantatos of EPRI addressed DER forum participants with a presentation on topics including inverter modelling, inverter operation in 'weak' power grids, transmission hosting capacity and the hypothetical operation of the BES with 100% inverter supply.

Question: Is there headroom for frequency response?
Answer: that was the assumption for the test.
Question: Can Grid forming inverters control frequency?
Answer: Yes. Fast frequency control and response.
Question: Why was their frequency overshoot?
Answer: Did not go into optimal setting adjustments to prevent overshoot of frequency.

16.3 NYISO Presentation on DER by James Pigeon

Mr. Pigeon updated DER forum participants on NYISO activities related to the interconnection and aggregation of DER resources.

Question: What consideration has been given to UFLS program requirements regarding applications for DER?

Answer: Utilities should review UFLS program requirements when they process DER applications. Aggregation should be considered when interconnection is requested.

ITWG Presentation on 1547 and NY Interconnection of DER by George Smith

Mr. Smith updated DER forum participants on issues related to IEEE Standard 1547 and PRC -024.

DPS Presentation on DER by Jason Pause

Mr. Pause updated DER forum participants on the NYS Department of Public Service interconnection requirements for DER.

Question: What inverter standard should be used?

Answer: Discussions regarding the topic and IEEE-1547 are in-progress now.

16.4 ISO-NE Presentation on DER by Dave Forrest

Mr. Forrest described current activities within ISO-NE on the implementation of IEEE 1547.

Question: Is DER penetration an issue for UFLS?
Answer: The UFLS program may become problematic.

16.5 Mr. Herb Schrayshuen Presentation on DER.

Mr. Schrayshuen presented a proposed regional approach to identify emerging risks to reliability related to DER implementation and ways to mitigate these risks.

Additionally, the development of a regional approach to identify potential reliability gaps related to the implementation of DER and the development of an Action Plan to address the changing resource mix.

16.6 Issues Raised by Stakeholders for Discussion and Approach to Resolution

The meeting is adjourned at 1:34PM on May 16, 2019.

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

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

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

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

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

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust

compliance policy is implicated in any situation should call NPCC's Secretary, Ruta Skučas, Esq. at 1-202-470-6428.

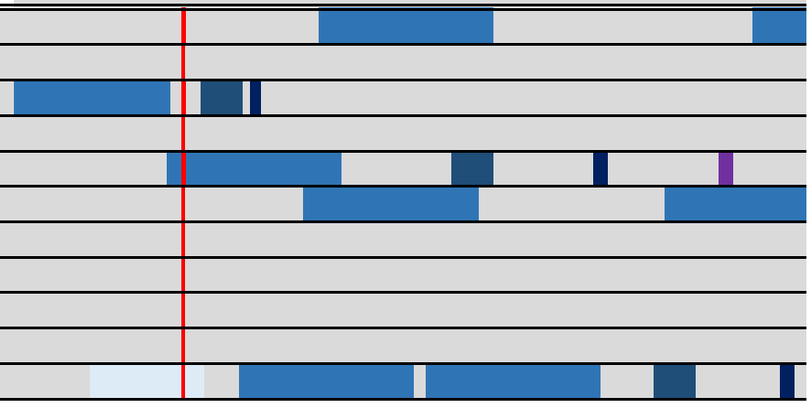
NPCC Representatives on NERC Standards Drafting Teams						
Project No.	**Project Title**	**DT Type**	**NPCC Representatives**	**Company**	**Telephone**	**E-mail Address**
2015-09	Establish and Communicate System Operating Limits - FAC-010, FAC-011, FAC-014	Standard	Dean Laforest Sam Jager	ISO-NE IESO		
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	Dominion Resource Services, Inc.		
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		
2017-07	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		
2018-02	2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Standard	Norm Dang Steve Brian	IESO Dominion Resource Services, Inc.		
2018-04	Modifications to PRC-024-2	Standard	Noel Aubut Tracy Macnicoll	Hydro Quebec Utility Services		
SER	Standard Efficiency Review	Standard	Greg Campoli (Advisers) Michael Puscus (Advisers)	NYISO ISO-NE		
2019-01	Modifictions to TPL-007-3	Standard	Per-Anders Lof (Vice Chair) Rui Sun Jow Ortiz Cynthia Yiu	National Grid Dominion Florida Power & Light (NextEra Energy) Hydro One		
Source = NERC Standard Drafting Team Rosters - July 2017						

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Updated: 7/19/2019

Nom-SAR/ | QR | Posting-SAR or | Posting-Comment | Posting Comment & B | Fina

Upd	HOME Project (Filter)	DO NOT SORT (Filtering Ok) Deliverables (Filter)	Early/(Late) Days (Filter)	Baseline/ Current (Filter)
	2015-09 - Establish and Communicate System Operating	CIP-014-3, FAC-003-5, FAC-011		Current
	2015-09b - Establish and Communicate System Operatin	IROL Stds.		On Hold
	2016-02c - Modifications to CIP Standards	CIP-002-6 - Address TO Contro	(647)	Current
	2016-02d - Modifications to CIP Standards	Address all remaining V5TAG is		N/A
	2017-01 - Modifications to BAL-003-1.1	BAL-003-2	(167)	Current
	2017-01b - Modifications to BAL-003-1.1	BAL-003-2		Proposed
	2017-03 - Periodic Review of FAC-008-3 Standard	PR Recommendations		On Hold
	2017-04 - Periodic Review of Interchange Scheduling anc	PR Recommendations		On Hold
	2017-05 - Periodic Review NUC-001-3	PR Recommendations		On Hold
	2017-07 - Stds Alignment with Registration	Standards with PSE, IA, or LSE		On Hold
	2018-04 - Modifications to PRC-024-2	TBD	(39)	Current



SUMMARY

Tutorial Video (11 min)

Click here to report errors or issues

Tabs along the bottom of the spreadsheet:

Green tab - Home Page listing all active projects

Yellow tabs - Help, Summary Page of projects, and Footnotes (far right tab)

Blue tabs - Indicate an active project.

Red tabs - Indicate a non-active project and are generally not shown, but may be revealed by "unhiding" the tab. If a red tab has an "underscore" preceding the project number (e.g., _YYYY-##) it means the project was added for developing metrics on previous projects not initially populated in this tracker.

Project Number nomenclature: The year started and the sequence (YYYY-##), a letter or .#/.alphabet letter denote the project was split into phases for tracking purposes. Phased projects in the tracker may or may not reflect the project being "Phased" on the www.nerc.com website.

Home Page - Gannt chart of active projects with current or proposed schedules, tyically set with the baseline schedule not showing.

Home Page - Filter is OKAY. Sorting will misalign the conditional formatting of the Gannt Chart.

Home Page - Column "B" is a freshness indicator of the underlying project page.

Home Page - Column "C" is the project name with an in document hyperlink to the respective project tab

Home Page - Column "D" lists the deliverables identified on the individual project pages

Home Page - Column "E" lists the number of days early or (late) a project is running based on the approved baseline schedule final ballot date.

Home Page - Column "F" lists the current status of the project "schedule" (See Note 6 in the footnotes for more information).

Home Page - Remaining columns to the right color code the what is anticipated in the project schedule. Proposed means the projected schedule or that it has been completed. If the projects are filtered on "baseline" the PMOS approved schedure is shown. To see previous time or future times, simply "unhide" the applicable columns using the spreadsheet functions.

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	Working to Additional Ballot	The standard drafting team (SDT) is working on proposed language for FAC-011 Requirement R7, TOP-001 and IRO-008. The team has received feedback on the logging/reporting time concept from FERC and NERC Standards staff and is working on data collection for SOL exceedances for analysis. This will help in finalizing a path forward. Work on potential IROL modifications will not be undertaken CIP	CIP-014-3, FAC-003-5, FAC-011-4, 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	Latrice Harkness & Darrel Richardson	Ken Lanehome	CIP-014-3, FAC-003-5, FAC-011, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-1 and the retirement of	7/9/2019	
2015-09b	Establish and Communicate System Operating Limits	On Hold	The IROL portion of the project has been placed on hold pending additional information. The SDT decided that IROL modifications will not be made to CIP	IROL Stds.	N/A	Medium	N/A	1	1	N/A	TBD - On Hold	TBD - On Hold	TBD - On Hold	7/9/2019	
2016-02c	Modifications to CIP Standards	Pending Board Adoption	The formal 45-day comment period, ballot, and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded 8 p.m. Eastern, Wednesday, July 17, 2019. The standard had an 87.39% approval. The team will determine next steps, which may be final ballot.	CIP-002-6 - Address TO Control Centers Performing Transmission Operator (TOP) Obligations.	N/A	Footnote 8, High	N/A			N/A	Jordan Mallory	Ken Lanehome, Ash Mayfield, and Kirk Rosener	CIP-002-5.1a	7/18/2019	
2016-02d	Modifications to CIP Standards	SDT Development	The team has been focusing on industry outreach to explain the issues and why updating the standards are necessary. SDT members have been presenting their plan at regional workshops. Most of the focus has been making edits to CIP-005 R1-R3, as well as related definitions. The case for change white paper is posted	Address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally	N/A	Footnote 8, High	N/A			N/A	Jordan Mallory	Ken Lanehome, Ash Mayfield, and Kirk Rosener	CIP-004, CIP-005, CIP-006, CIP-007 and CIP-010	7/9/2019	
2017-01	Modifications to BAL-003-1.1	SDT Development	NERC staff anticipate the study regarding Interconnection Frequency Response Obligation (IFRO) to conclude mid-June. The study aims to ensure there will not be reliability issues created by any SDT proposed changes. Board delivery has been adjusted from May to November and the timeline is behind about two quarters due to the survey and bumping Board delivery to the November meeting.	BAL-003-2	N/A	Footnote 8, Medium	N/A			N/A	Laura Anderson	Amy Casuscelli & Linda Lynch	BAL-003-1.1	7/9/2019	
2017-01b	Modifications to BAL-003-1.1	SDT Development	The team met June 18-19, 2019 to begin drafting documents.	BAL-003-2	N/A	Footnote 8, Medium	N/A			N/A	Laura Anderson	Amy Casuscelli & Linda Lynch	BAL-003-1.1	7/9/2019	
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	Al McMeekin	Mark Pratt	FAC-008-3	7/9/2019	
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	Laura Anderson	Charles Yeung	INT-004, INT-006, INT-009, and INT-010	7/9/2019	

2017-05	Periodic Review NUC-001-3	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 Recommendations	N/A	Footnote 9, Low (was Medium previously)	N/A			N/A	Mat Bunch	Amy Casuscelli and Colby Bellville	NUC-001-3	7/9/2019	
2017-07	Stds Alignment with Registration	On Hold	The project is on a temporary hold for coordination with other projects (such as Standards Efficiency Review and CIP) because many of the requirements that address these functional entities, are being considered for retirement. The project is not as simple as just removing a requirement with PSE, IA or LSE. The removal of the requirement may create a gap that would need to be addressed by another functional entity such as Distribution Provider (DP) or Transmission Owner (TO). This project is not addressing a reliability issue and has a low priority in the RSDP; therefore, the project is in a holding pattern in the interim.	Standards with PSE, IA, or LSE		Footnote 9, Low	N/A			N/A	Laura Anderson	Mike Brytowski	Standards with PSE, IA, or LSE	7/9/2019	
2018-04	Modifications to PRC-024-2	SDT Development	A supplemental SAR is posted through July 26, 2019.	TBD	N/A	N/A	N/A			N/A	Mat Bunch	Linda Lynch	PRC-024-2	6/26/2019	
2019-01	Modifications to TPL-007-3	SAR / PR / WP	The team met June 4-5, 2019.	TPL-007-4	6/30/2020		N/A	1		N/A	Alison Oswald	Michael Brytowski & Sean Cavote	TPL-007-3	6/26/2019	
2019-02	BES Cyber System Information Access Management	Posted	The Standard Authorization Request (SAR) was posted for formal comment through April 26, 2019. The SAR team was appointed by the Standards Committee (SC) on May 22. The team met June 18-	TBD	N/A		N/A			N/A	Latrice Harkness	Colby Bellville and Kirk Rosener	CIP-004 and CIP-0011	6/26/2019	
2019-03	Project 2019-03 Cyber Security Supply Chain Risks	SAR / PR / WP	A 30-day informal comment period for the Project 2019-03 Cyber Security Supply Chain Risks Standard Authorization Request (SAR) is	CIP-005-6, CIP-100-3, and CIP-013-1	12/25/2020		N/A	1		N/A	Alison Oswald	TBD - August 7, 2019	CIP-005-6, CIP-100-3, and CIP-	6/26/2019	

PMOS ROSTER & LIAISON BURDEN

Term	Name	Entity	2015-09	2015-09b	2016-02c	2016-02e	2017-01	2017-01b	2017-03	2017-04	2017-05	2017-07	2018-03	2018-04	2019-01	2019-02
2019-2020	Charles Yeung	Southwest Power Pool, Inc.								X						
2018-2019	Michael Brytowski	Great River Energy										X	X		X	
2018-2019	Colby Bellville	Duke Energy									X					X
2019-2020	Sean Cavote	PSEG Services Company													X	
2019-2020	Ken Lanehome	Bonneville Power Administration	X		X	X										
2018-2019	Linda Lynch	NextEra Energy | Florida Power & Light					X	X						X		
2019-2020	Ash Mayfield	Grand River Dam Authority			X	X										
2018-2019	Mark Pratt	Southern Company							X				X			
2018-2019	Kirk Rosener	CPS Energy			X	X										X
SC Chair	Andrew Gallo	City of Austin, dba Austin Energy														
SC Vice Chair	Amy Casuscelli	Xcel Energy					X	X			X					
NERC Staff	Scott Barfield-McGinnis, Secretary	North American Electric Reliability Corporation														
NERC Staff	Marisa Hecht, Legal	North American Electric Reliability Corporation														

Project	**Standards Efficiency Review**	**Home**
Project Name	Overview for PMOS	
Status	Other	
Comments	The Standards Authorization Request was posted through September 26, 2018. The drafting team will be having the kick-off meeting on November 6, 2018, see the NERC calendar for details.	
Deliverable		
Operations Planning Subteam	Amy Casuscelli & Charles Yeung	
Real-time Operations Subteam	Mike Brytowski	
Long-term Planning Subteam	Linda Lynch	
SER Phase 1	Mike Brytowski & Mark Pratt	
SER Phase 2 (Concepts)	Mike Brytowski & Linda Lynch	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Chris Larson	
PMOS Liaison	Mark Pratt & Michael Brytowski	
Affected Standards	See SAR (too many to list)	
Last Updated	6/25/2019	

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

Project	**2015-09**			**Home**
Project Name	Establish and Communicate System Operating Limits			
Status	Working to Additional Ballot			
Comments	The standard drafting team (SDT) is working on proposed language for FAC-011 Requirement R7, TOP-001 and IRO-008. The team has received feedback on the logging/reporting time concept from FERC and NERC Standards staff and is working on data collection for SOL exceedances for analysis. This will help in finalizing a path forward. It has been decided that IROL modifications will not be made to CIP-002 at this time. The CIP SDT (2016-02c) will finish their work and post with no changes to the IROL language. CIP-002 will be re-opened during phase 2 of this project to address the IROL language. The FAC-015 sub-group has drafted proposed language and presented to the team on May 29, 2019 for support of the clarifications based on industry comments. Options include making clarifying revisions to FAC-015 based on comments, transfer Requirements to other FAC standards, or moving to TPL-001			
Deliverable	CIP-014-3, FAC-003-5, FAC-011-4, 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	**Priority (1-Low, 2-Med, 3-High)**	2	**Project has been Re-Baselined? (0-No, 1-Yes)** 1
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	Latrice Harkness & Darrel Richardson			
PMOS Liaison	Ken Lanehome			
Affected Standards	7	CIP-014-3, FAC-003-5, FAC-011, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-1 and the retirement of FAC-010		
Last Updated	7/9/2019			

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	8/24/2018	10/17/2018	1/17/2018	3/2/2018	(219)		
CAB - Com/Add Ballot 3	8/26/2019	10/10/2019	8/26/2019	10/10/2019			**New baseline starts here**
CAB - Com/Add Ballot 4	12/18/2019	2/1/2020	12/18/2019	2/1/2020			
CAB - Com/Add Ballot 5							
FB - Final Ballot	2/11/2020	2/21/2020	2/11/2020	2/21/2020			
PTB - Present to BOT	5/13/2020	5/15/2020	5/13/2020	5/15/2020			
Filing - Filing with Regulators	6/14/2020	6/17/2020	6/14/2020	6/17/2020			
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	**2015-09b**				**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. The SDT decided that IROL modifications will not be made to CIP-002 at this time. The CIP SDT (2016-02c) will finish their work and post with no changes to the IROL language. CIP-002 will be re-opened during phase 2 of this project to address the IROL language.				
Deliverable	IROL Stds.				
Deadline	N/A				
Priority in RSDP, click to see applicable Footnote	Medium		**Priority (1-Low, 2-Med, 3-High)**	2	**Project has been Re-Baselined? (0-No, 1-Yes)**
P81 Req (2013)	N/A				
Number of Directives	1	Confirm			
No. of Guidances (see Note 2)	1	Confirm			
Directionally consistent with IERP findings (See Note 5)	N/A				
Developer	TBD - On Hold				
PMOS Liaison	TBD - On Hold				
Affected Standards		TBD - On Hold			
Last Updated	7/9/2019				

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	**2016-02c**			**Home**
Project Name	Modifications to CIP Standards			
Status	Pending Board Adoption			
Comments	The formal 45-day comment period, ballot, and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded 8 p.m. Eastern, Wednesday, July 17, 2019. The standard had an 87.39% approval. The team will determine next steps, which may be final ballot.			
Deliverable	CIP-002-6 - Address TO Control Centers Performing Transmission Operator (TOP) Obligations.			
Deadline	N/A			
Priority in RSDP, click to see applicable Footnote	Footnote 8, High	**Priority (1-Low, 2-Med, 3-High)**	3	**Project has been Re-Baselined? (0-No, 1-Yes)** 1
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	1 CIP-002-5.1a			
Last Updated	7/18/2019			

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	3/23/2016	4/21/2016			(42452)		
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	3/16/2018	4/30/2018	3/31/2017	5/14/2017	(350)		
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	6/3/2019	7/17/2019					Ballot Pools re-opened
CAB - Com/Add Ballot 5							
FB - Final Ballot	***7/26/2019***	***8/5/2019***	10/17/2017	10/27/2017	(647)		
PTB - Present to BOT	8/8/2019	8/10/2019	11/7/2017	11/9/2017	(639)		
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 leaving Jordan Mallory.

Home

Project 2016-02d

Project Name	Modifications to CIP Standards
Status	SDT Development
Comments	The team has been focusing on industry outreach to explain the issues and why updating the standards are necessary. SDT members have been presenting their plan at regional workshops. Most of the focus has been making edits to CIP-005 R1-R3, as well as related definitions. The case for change white paper is posted for a 30-day informal comment period ended June 28.
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
Priority (1-Low, 2-Med, 3-High)	3
Project has been Re-Baselined? (0-No, 1-Yes)	
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	5 CIP-004, CIP-005, CIP-006, CIP-007 and CIP-010
Last Updated	7/9/2019

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	2/28/2019	3/29/2019	2/28/2019	3/29/2019			
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	5/30/2019	6/28/2019	5/30/2019	6/28/2019			Case for Change WP
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	*8/1/2019*	*8/31/2019*	*8/1/2019*	*8/31/2019*			
CP2 - Comment Period 2	11/1/2019	12/1/2019	11/1/2019	12/1/2019			
CIB - Com/Ballot 1 (Initial)	3/13/2020	4/27/2020	3/13/2020	4/27/2020			
CAB - Com/Add Ballot 2	6/22/2020	8/6/2020	6/22/2020	8/6/2020			
CAB - Com/Add Ballot 3	9/18/2020	11/2/2020	9/18/2020	11/2/2020			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	11/16/2020	11/26/2020	11/16/2020	11/26/2020			
PTB - Present to BOT	12/15/2020	12/17/2020	12/15/2020	12/17/2020			
Filing - Filing with Regulators	1/16/2021	1/19/2021	1/16/2021	1/19/2021			
PT - Post Approval Training							

Prior to 6/26/2019

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead	Reason for Change or	Ballot or Other
Nominations - SAR / PR							
Nominations - DT	2/28/2019	3/29/2019			(43524)		Augment
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1	3/23/2016	4/21/2016			(42452)		
SP2 - SAR/PR/WP Posting 2	11/2/2018	12/18/2018					3rd
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	3/5/2019	4/19/2019	12/14/2018	1/28/2019	(81)		Went
CAB - Com/Add Ballot 3			3/2/2019	4/19/2019			ballot 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	8/6/2019	8/8/2019			
Filing - Filing with Regulators	9/1/2019	9/4/2019	9/1/2019	9/4/2019			

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.
SDT Augmented	5/22/2019	The SC accepted the recommended slate of candidates.
Re-baseline	6/26/2019	PMOS accepted the baseline for virtualization now that other focus areas are complete.

Project	**2017-01**				**Home**
Project Name	Modifications to BAL-003-1.1				
Status	SDT Development				
Comments	NERC staff anticipate the study regarding Interconnection Frequency Response Obligation (IFRO) to conclude mid-June. The study aims to ensure there will not be reliability issues created by any SDT proposed changes. Board delivery has been adjusted from May to November and the timeline is behind about two quarters due to the survey and bumping Board delivery to the November meeting.				
Deliverable	BAL-003-2				
Deadline	N/A				
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium		**Priority (1-Low, 2-Med, 3-High)**	2	**Project has been Re-Baselined? (0-No, 1-Yes)**
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	1	BAL-003-1.1			
Last Updated	7/9/2019				

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)	12/4/2018	1/17/2019	11/6/2018	1/9/2019	(28)		
CAB - Com/Add Ballot 2	**7/17/2019**	**8/31/2019**	2/18/2019	4/3/2019	(149)		not needed - passed at 96.41%
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	9/30/2019	10/10/2019	4/16/2019	4/26/2019	(167)		
PTB - Present to BOT	11/6/2019	11/9/2019	5/9/2019	5/12/2019	(181)		
Filing - Filing with Regulators	12/9/2019	12/12/2019	6/9/2019	6/12/2019	(183)		
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.
Schedule adjustment	3/20/2019	The schedule moved out three months due to the IFRO study needed to ensure the SDT proposed changes do not create an issue.
Additional Ballot	7/9/2019	Decision made to go to an additional ballot 2 rather than final ballot.

Project	**2017-01b**				**Home**
Project Name	Modifications to BAL-003-1.1				
Status	SDT Development				
Comments	The team met June 18-19, 2019 to begin drafting documents.				
Deliverable	BAL-003-2				
Deadline	N/A				
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium		**Priority (1-Low, 2-Med, 3-High)**	2	**Project has been Re-Baselined? (0-No, 1-Yes)**
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	1	BAL-003-1.1			
Last Updated	7/9/2019				

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	8/22/2019	10/6/2019	8/22/2019	10/6/2019			
CAB - Com/Add Ballot 2	11/25/2019	1/9/2020	11/25/2019	1/9/2020			

CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	2/11/2020	2/21/2020	2/11/2020	2/21/2020			
PTB - Present to BOT	5/13/2020	5/16/2020	5/13/2020	5/16/2020			
Filing - Filing with Regulators	6/15/2020	6/18/2020	6/15/2020	6/18/2020			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	3/7/2019	Created Project record per action item from PMOS 2/13/2019 meeting.
Baseline	5/15/2019	PMOS accepted baseline as presented.

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)		**Priority (1-Low, 2-Med, 3-High)**	3	**Project has been Re-Baselined? (0-No, 1-Yes)**
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	1	FAC-008-3			
Last Updated	7/9/2019				

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)	**Priority (1-Low, 2-Med, 3-High)**	3	**Project has been Re-Baselined? (0-No, 1-Yes)**
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	4	INT-004, INT-006, INT-009, and INT-010		
Last Updated	7/9/2019			

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	Periodic Review NUC-001-3				
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 Recommendations				
Deadline	N/A				
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)		**Priority (1-Low, 2-Med, 3-High)**	3	**Project has been Re-Baselined? (0-No. 1-Yes)**
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	1	NUC-001-3			
Last Updated	7/9/2019				

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	On Hold	
Comments	The project is on a temporary hold for coordination with other projects (such as Standards Efficiency Review and CIP) because many of the requirements that address these functional entities, are being considered for retirement. The project is not as simple as just removing a requirement with PSE, IA or LSE. The removal of the requirement may create a gap that would need to be addressed by another functional entity such as Distribution Provider (DP) or Transmission Owner (TO). This project is not addressing a reliability issue and has a low priority in the RSDP; therefore, the project is in a holding pattern in the interim.	
Deliverable	Standards with PSE, IA, or LSE	
Deadline		
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low	**Priority (1-Low, 2-Med, 3-High)** 3 **Project has been Re-Baselined? (0-No, 1-Yes)**
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	7/9/2019	

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			
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			
PTB - Present to BOT			2/5/2019	2/8/2019			
Filing - Filing with Regulators			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.
Schedule adjustment	10/31/2018	The PMOS removed the "projected schedule" as it was inaccurate and misleading.

Project	**2018-04**				**Home**
Project Name	Modifications to PRC-024-2				
Status	SDT Development				
Comments	A supplemental SAR is posted through July 26, 2019.				
Deliverable	TBD				
Deadline	N/A				
Priority in RSDP, click to see applicable Footnote	N/A		**Priority (1-Low, 2-Med, 3-High)**	3	**Project has been Re-Baselined? (0-No, 1-Yes)**
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	Linda Lynch				
Affected Standards	1	PRC-024-2			
Last Updated	7/9/2019				

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	12/19/2018	1/18/2019					
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	12/19/2018	1/18/2019					
SP2 - SAR/PR/WP Posting 2	6/27/2019	7/26/2019					Supl. SAR
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	4/17/2019	5/31/2019	4/17/2019	6/1/2019			
CAB - Com/Add Ballot 2	8/5/2019	9/19/2019	6/17/2019	8/1/2019	(49)		
CAB - Com/Add Ballot 3	9/23/2019	11/7/2019	8/15/2019	9/29/2019	(39)		
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	11/22/2019	12/2/2019	10/14/2019	10/24/2019	(39)		
PTB - Present to BOT	12/25/2019	12/28/2019	11/7/2019	11/10/2019	(48)		
Filing - Filing with Regulators	1/27/2020	1/29/2020	12/10/2019	12/12/2019	(48)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
New Project	9/13/2018	Project is indefinitely on hold due to SC rejecting the SARs.
Re-initiated	12/12/2018	The SC authorized the SAR (revised by SCPS) to move forward.
SC Action	1/31/2019	Appointment of drafting team.
Tentative Baseline Schedule	2/13/2019	A draft baseline schedule was shared with the PMOS.
Accept Baseline	6/26/2019	PMOS accepted the proposed baseline as presented.
SC Action	6/26/2019	SC authorized posting of supplemental SAR.

Project	**2019-01**				**Home**
Project Name	Modifications to TPL-007-3				
Status	SAR / PR / WP				
Comments	The team met June 4-5, 2019.				
Deliverable	TPL-007-4				
Deadline	**6/30/2020**			**11**	**Months to deadline**
Priority in RSDP, click to see applicable Footnote		**Priority (High, Med, Low is 1, 2, 3)**	2	**Project has been Re-Baselined? (0-No, 1-Yes)**	
P81 Req (2013)	N/A				
Number of Directives	1	FERC Order No. 851			
No. of Guidances (see Note 2)		N/A			
Directionally consistent with IERP findings (See Note 5)	N/A				
Developer	Alison Oswald				
PMOS Liaison	Michael Brytowski & Sean Cavote				
Affected Standards	1	TPL-007-3			
Last Updated	7/9/2019				

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	2/25/2019	3/26/2019					
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	2/25/2019	3/26/2019					
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	***7/29/2019***	***9/12/2019***	***7/29/2019***	***9/12/2019***			
CAB - Com/Add Ballot 2	10/21/2019	12/5/2019	10/21/2019	12/5/2019			

CAB - Com/Add Ballot 3	1/23/2020	3/8/2020	1/23/2020	3/8/2020			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	4/20/2020	4/30/2020	4/20/2020	4/30/2020			
PTB - Present to BOT	5/13/2020	5/16/2020	5/13/2020	5/16/2020			
Filing - Filing with Regulators	6/15/2020	6/18/2020	6/15/2020	6/18/2020			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Accept SAR	2/20/2019	Standards Committee accepted the SAR for posting
PMOS Liaison Assigned	3/20/2019	M. Brytowski and S. Cavote volunteered to follow the project.
Accept Baseline	5/15/2019	PMOS accepted the proposed baseline as presented

Project	**2019-02**			**Home**
Project Name	BES Cyber System Information Access Management			
Status	Posted			
Comments	The Standard Authorization Request (SAR) was posted for formal comment through April 26, 2019. The SAR team was appointed by the Standards Committee (SC) on May 22. The team met June 18-19, 2019 to revise the SAR. The team anticipates presenting the SAR for SC acceptance on July 24, 2019.			
Deliverable	TBD			
Deadline	N/A			
Priority in RSDP, click to see applicable Footnote		**Priority (High, Med, Low is 1, 2, 3)**	**Project has been Re-Baselined? (0-No, 1-Yes)**	
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	Latrice Harkness			
PMOS Liaison	Colby Bellville and Kirk Rosener			
Affected Standards	2 CIP-004 and CIP-0011			
Last Updated	7/9/2019			

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	3/28/2019	4/26/2019					
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
Accept SAR	3/20/2019	Standards Committee Action
Assign PMOS Liaison	5/15/2019	Colby Bellville and Kirk Rosner were appointed as liaisons to the project.
Appoint SDT	5/22/2019	The SC appointed the slate of nominees based on changes during the meeting.
SAR Accepted	7/24/2019	SC accepted SAR and authorized solicitation for a drafting team.

Project	**2019-03**			**Home**
Project Name	Project 2019-03 Cyber Security Supply Chain Risks			
Status	SAR / PR / WP			
Comments	A 30-day informal comment period for the Project 2019-03 Cyber Security Supply Chain Risks Standard Authorization Request (SAR) is open through 8 p.m. Eastern, Thursday, August 1, 2019. Additionally, nominations are being sought for SAR drafting team members through 8 p.m. Eastern, Thursday, August 1, 2019.			
Deliverable	CIP-005-6, CIP-100-3, and CIP-013-1			
Deadline	12/25/2020		**17**	**Months to deadline**
Priority in RSDP, click to see applicable Footnote		**Priority (High, Med, Low is 1, 2, 3)**	**Project has been Re-Baselined? (0-No, 1-Yes)**	
P81 Req (2013)	N/A			
Number of Directives	1	This project will address the directives issued by FERC in Order No. 850. This project will also address NERC staff recommendation from the Supply Chain Report.		
No. of Guidances (see Note 2)		N/A		
Directionally consistent with IERP findings (See Note 5)	N/A			
Developer	Alison Oswald			
PMOS Liaison	TBD - August 7, 2019			
Affected Standards	2	CIP-005-6, CIP-100-3, and CIP-013-1		
Last Updated	7/10/2019			

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	7/2/2019	8/1/2019					
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	7/2/2019	8/1/2019					
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
New Project	7/10/2019	Setup PTS for tracking.
Assign Liason	8/7/2019	TBD

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. On Hold - Project is held temporarily (e.g., due to coordination with other projects) 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 #19-3, Agenda Item 4.0 Open Action Items

Item	Description	Owner	Due	Status
4.1	Mike Jones, Quintin and Herb Schrayshuen volunteered to assist Guy Zito and Ruida Shu on reviewing the NPCC RSPM Guy Zito and Ruida Shu will review the draft redline from the subgroup.	Guy Zito Ruida Shu	By end of 2019	Pending
4.2	RSC to review the Cost-Effective Pilot on Directory #4 and #5.	RSC	During the May 2019 RSC Meeting	Pending

DRAFT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards, Compliance, and Enforcement Bulletin

July 29–August 4, 2019

INSIDE THIS EDITION

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

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
NEW 2019-01 – Modifications to TPL-007-3 | TPL-007-4	Initial Ballot and Non-binding Poll	08/30/19	09/09/19
Project	**Action**	**Start Date**	**End Date**
NEW 2019-01 – Modifications to TPL-007-3 | TPL-007-4	Join Ballot Pools	07/26/19	08/26/19
Posted for Comment			
Project	**Action**	**Start Date**	**End Date**
Project 2019-03 – Cyber Security Supply Chain Risks	Comment Period	07/02/19	08/01/19
NEW 2019-01 – Modifications to TPL-007-3 | TPL-007-4	Comment Period	07/26/19/	09/09/19

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
Comment Period Open for Second Draft of NERC's 2020 Business Plan and Budget: The second draft of NERC's 2020 Business Plan and Budget and final drafts of the Regional Entities' 2020 Business Plans and Budgets are now available for comment on NERC's website. A presentation providing a summary of the NERC 2020 Business Plan and Budget and ERO Enterprise combined 2020 budgets and assessments are posted as part of these materials. Presentations providing a summary of each Regional Entity business plan and budget are also posted. NERC has posted the following documents for review and/or comment: • Cover Letter from Andy Sharp, Interim Chief Financial Officer and Controller • NERC 2020 Business Plan and Budget Overview • ERO Enterprise Combined 2020 Budgets and Assessments Overview	Submit all comments to Erika Chanzes.	07/15/19	07/31/19
Comment Period Open for Regional Reliability Standard BAL-002-WECC-3: WECC received a Standard Authorization Request requesting retirement of BAL-002-WECC-2a, Requirement R2 as it would become redundant with the implementation of BAL-003-1.1., Requirement R1 on April 1, 2016. WECC conducted a field test and concluded that the retirement of BAL-002-WECC-2a, Requirement R2 would not have an adverse impact on reliability. Therefore, WECC	Use the SBS to submit comments. If you experience any difficulties using the electronic form, contact Nasheema Santos.	06/20/19	08/05/19

proposes to retire Requirement R2 in WECC Regional Reliability Standard BAL-002-WECC-3.			
Comment Period Open for Parameterization of the DER_A Model Draft Reliability Guideline: The NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) developed the draft Reliability Guideline: Parametrization of the DER_A Model. This reliability guideline provides background on the DER modeling framework previous proposed in other NERC Reliability Guidelines, information on relevant interconnection standards (e.g., IEEE Std. 1547-2003, IEEE Std. 1547a-2014, IEEE Std. 1547-2018, and CA Rule 21), and how the DER_A model parameters can be modified to account for a mixture of vintages of inverter-interfaced DER. The Planning Committee reviewed the initial draft of the guideline and approved posting for industry comment. A draft version of the Reliability Guideline has been posted on the NERC website for industry comment.	Submit comments via email using the comment form.	06/24/19	08/07/19
Comment Period Open for Proposal for Restructuring NERC Technical Committees: A stakeholder engagement team (SET) was formed to address and improve the effectiveness and efficiency of how stakeholders engage with NERC to advance our critical reliability and security mission. Given the nature of our model and criticality of industry expertise to the ERO's success, enhancing the effectiveness of stakeholder participation in the face of our rapidly changing industry is the primary objective of the initiative, always keeping an eye on the need to be as efficient as reasonably possible given all of the other demands on participants and staff. The SET was asked to review the existing NERC technical committee structure (i.e., Critical Infrastructure Protection Committee (CIPC),	Submit comments to Stephen Crutchfield.	07/12/19	08/15/19

Operating Committee (OC), and Planning Committee (PC)) and develop recommendations for improving their effectiveness and efficiency. Based on this detailed review and as outlined in the Proposal for Restructuring NERC Technical Committees, the team is recommending replacing the three committees with a Reliability and Security Council (RSC). The RSC would report to the NERC Board of Trustees and focus on managing the work of the various subcommittees, working groups, and task forces organized to address specific risks to reliability and security. The SET is seeking stakeholder input on the following: 1. The proposal to replace the NERC CIPC, OC, and PC with the RSC. 2. The proposed participation model of the RSC. 3. The best way to implement the transition from three technical committees to the RSC. For more information, please see the full announcement or contact Sandy Shiflett.			
Feedback Solicitation Open for CIP Standards Efficiency Review (SER): NERC is soliciting industry feedback on areas of inefficiency within the CIP Standard Requirements through **August 26, 2019**. This feedback is to be documented on the CIP SER Matrix. For more information or assistance, contact Brian Allen.	Submit the completed CIP SER Matrices via email.	07/03/19	08/26/19
Team Nomination Period Open for CIP Standards Efficiency Review: NERC is assembling a team to perform analysis of the responses to the CIP SER Matrix as well as to prioritize efforts and identify next steps. For more information or assistance, contact Brian Allen.	Submit the completed nomination form via email.	07/03/19	08/16/19

STANDARDS NEWS

NEW Update to Standards Navigation on NERC Website

After reviewing and analyzing recent analytics, NERC determined that Standards website pages consistently have more traffic than any other sites on NERC.com. In fact, 7 out of 10 of the most visited website pages during the last year have been to Standards pages.

Based on stakeholder feedback and in an effort to make Standards more visible and accessible, NERC has added the main Standards page to the top navigation bar. This means there are now three ways to quickly and directly access the Standards home page—through the new Standards link on the top navigation bar, through the Program Areas & Department dropdown on the top navigation bar, and through the Standards section on the NERC.com landing page.

Quick Links

- Register in the SBS
- Projected Standards Posting Schedule
- Project Tracking Spreadsheet
- Standards Related Questions – Single Portal
- 2019–2021 Reliability Standards Development Plan
- Quality Review Application
- One-Stop Shop (Status, Purpose, Implementation Plans, FERC Orders, RSAWs)
- CIP Standards Efficiency Review

NEW Resources Posted

NERC has posted the presentations from the July 25, 2019 Electromagnetic Pulse Task Force Workshop.

NEW Standards Committee Special Election – Segment 9

Segment 9—Federal, State, and Provincial Regulatory or other Government Entities—currently has a vacancy for the remainder of the 2019–2020 term. Nominations are being accepted through August 19, 2019, in preparation for a special election for Segment 9 to fill the remainder of the term.

Registered Ballot Body (RBB) members and others interested in NERC Reliability Standards are encouraged to submit nominations for industry segment representatives on the Standards Committee (SC). Reliability Standards are mandatory for all bulk power system owners, operators, and users in North America, and the SC's oversight role is therefore increasingly important. The SC consists of two members from each of the ten Industry Segments that make up the RBB. In addition, Appendix 3B of the Rules of Procedure contains special provisions to be used to achieve a balance of representation between the United States and Canada. The SC is elected by industry stakeholders and reports directly to the NERC Board of Trustees. The SC meets up to twelve times each year, with four face-to-face meetings and the remainder by conference call. The Standards Committee Charter provides a description of the SC's responsibilities.

Anyone may submit a nomination. To be eligible for nomination, a nominee shall be an employee or agent of an entity belonging in the applicable Segment. **To allow verification of affiliation, a nominee must be a registered user in the NERC RBB**. It is not required that the nominee be the same person as the entity's RBB representative for the applicable Segment. Instructions are provided in the Election of Members of the NERC Standards Committee Procedure and nomination forms are posted on the Standards Committee Election web page. To submit a nomination, complete and submit to Linda Jenkins no later than **August 19.** Once received, nominations will be posted on the SC's Nominations and Election web page.

The special election will be conducted **August 27–September 5.** Election results will be announced shortly after the election closes.

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

There is no additional Compliance and Enforcement news to report for this week.

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
- Align Project (formerly CMEP Technology Project)

OTHER NEWS

NEW Search for NERC Leadership Positions Underway

NERC has engaged Lyceum Leadership Consulting to conduct its search for two leadership positions: senior vice president, general counsel, and corporate secretary; and senior vice president, chief financial, and administrative officer. Lyceum will conduct the initial executive search and provide qualified candidates to NERC's chief executive officer and other senior executives for review. Qualified candidates should review the position descriptions on Lyceum's website for more information and send an email with their resume to Carly Olson.

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)**
January 1, 2020	CIP-003-7 – Cyber Security — Security Management Controls
	PRC-026-1 – Relay Performance During Stable Power Swings (Requirements R2–R4)
	TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements R5, 5.1, 5.2, R9, 9.1, and 9.2)
July 1, 2020	CIP-005-6 – Cyber Security – Electronic Security Perimeter(s) CIP-010-3 – Cyber Security — Configuration Change Management and Vulnerability Assessments CIP-013-1 – Cyber Security — Supply Chain Risk Management
	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (50% compliance for Requirements R2–R4, R6–R11)
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
July 1, 2021	TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements R11 and R12)
January 1, 2022	TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements R6, 6.1–6.4, R10, 10.1–10.4)
July 1, 2022	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (100% compliance for Requirements R2–R4, R6–R11)
January 1, 2023	TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements R3, R4, 4.1. 4.1.1–4.1.2, 4.2, 4.3, 4.3.1, R8, 8.1, 8.1.1–8.1.2, 8.3, 8.4, and 8.4.1)
January 1, 2024	TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements R7, 7.1, 7.2, 7.3, 7.3.1–7.3.2, 7.4, 7.4.1–7.4.3, 7.5, and 7.5.1.)

BOARD OF TRUSTEES AND FERC ACTION

NEW NERC Filings

On July 22, 2019, NERC submitted to FERC the Five-Year Electric Reliability Organization Performance Assessment Report (Performance Assessment) in accordance with 18 C.F.R. § 39.3(c)(1) (2018). The Performance Assessment: (i) identifies how the ERO Enterprise's activities and achievements during the Assessment Period build upon the certification criteria of 18 C.F.R. § 39.3(b); (ii) evaluates the effectiveness of each Regional Entity in carrying out its Delegated Authority; and (iii) addresses stakeholder comments on NERC's performance (included as Attachment C to the Performance Assessment). At this time, the petition remains un-docketed by FERC. NERC will update the docket number on its website when it is assigned.

On July 26, 2019, NERC submitted to FERC the first informational filing regarding the results of work performed under the Geomagnetic Disturbance Research Plan in Docket No. RM15-11-003 in accordance with Order No. 830.

NERC's 2019 filings to FERC are available here.

UPCOMING EVENTS

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

Workshops and Conferences

- 2019 Industry Standards and Compliance Workshop – July 23–24, 2019, Minneapolis, MN | In-person Registration | Webinar Registration | Hotel Registration | Agenda
- Electromagnetic Pulse Task Force Workshop – 8:30 a.m.–5:00 p.m. Eastern, July 25, 2019, Atlanta | In-person Registration | Webinar Registration | Agenda
- Monitoring and Situational Awareness Technical Conference – September 24–25, 2019, Little Rock, AR | Register | Hotel and Travel Information | Presentations from Previous Conferences
- GridSecCon 2019 – October 22–25, 2019, Atlanta | Register
- SAVE THE DATE Probabilistic Analysis Forum – December 11–13, 2019, Atlanta | **Registration Coming Soon**

Webinars

- **NEW** Project 2019-01 – Modifications to TPL-007-3 Webinar – 1:30–2:30 p.m. Eastern, August 2, 2019 | Register
- Proposal for Restructuring NERC Technical Committees Webinar – Noon–1:00 p.m. Eastern, August 8, 2019 | Register
- Electromagnetic Transient Simulations for Large-Scale Systems Studies with High Penetration of Inverter-Based Resources Webinar – 4:30–5:30 p.m. Eastern, August 12, 2019 | Register

Standing Committee Meetings and Conference Calls

- Standards Committee Conference Call – 1:00–3:00 p.m. Eastern, July 24, 2019 | Register | Agenda Package
- Board of Trustees Committees, Member Representatives Committee, and Board of Trustees Meetings – August 14–15, 2019, Québec, QC | Meeting Registration and Hotel Information **Rate cutoff: July 22**
- Critical Infrastructure Protection Committee Meeting – September 17–18, 2019, Minneapolis, MN | Register

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 2017-01 – Modifications to BAL-003-1.1 Drafting Team Meeting – July 22–23, 2019, Lakewood, CO| Register
- Project 2018-04 – Modifications to PRC-024-2 Drafting Team Conference Call – 1:00–3:00 p.m. Eastern, July 31, 2019 | Register
- **NEW** Project 2019-02 – BES Cyber System Information Access Management Drafting Team Meeting – August 6–7, 2019, Atlanta | Register
- Project 2018-04 – Modifications to PRC-024-2 Drafting Team Conference Call – Noon–4:00 p.m. Eastern, August 8, 2019 | Register
- Project 2018-04 – Modifications to PRC-024-2 Drafting Team Conference Call – 11:00 a.m.–3:00 p.m. Eastern, August 26, 2019 | 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).

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

Northeast Power Coordinating Council, Inc.

Regional Standard Processes Manual (RSPM)



Approved by FERC: XX/XX/XX ~~December 23, 2014~~

Approved by NERC Board of Trustees: XX/XX/XX
~~August 14, 2014~~

Approved by NPCC Board of Directors: XX/XX/XX
~~March 11, 2014~~

Revision History

Version	NPCC Board of Directors Approval	NERC Board of Trustees Approval	FERC Approval
0	9/19/07	10/23/07	3/21/08
1	3/11/14	8/14/14	12/23/14
2	xx/xx/xx	xx/xx/xx	xx/xx/xx

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NPCC REGIONAL RELIABILITY STANDARDS PROCESS MANUAL

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I. EXECUTIVE SUMMARY

The NPCC Bylaws state "NPCC shall develop a Regional Reliability Standards Development Procedure that provides the design-basis approach to a consensus building process by which NPCC may develop Regional Reliability Standards and Regional Variances to be proposed to the ERO for adoption, under delegated authority by the FERC and the Canadian Provincial regulatory and/or governmental authorities."

The NPCC Regional Reliability Standards Development Procedure was originally adopted by the NPCC Board of Directors on September 19, 2007. Revision 1 of the manual was adopted by the NPCC Board of Directors on March 11, 2014.

The NPCC Regional Standard Process Manual conforms with NERC Rules of Procedure Section 300 Reliability Standards Development for Regional Reliability Standards

~~The NPCC Reliability Standards Staff in concert with the NPCC Regional Standards Committee (RSC) has completed a revision to the NPCC Regional Reliability Standards Process Manual to incorporate process improvements, provide greater clarity and reflect the new NPCC Cost Effectiveness Analysis Procedure (CEAP).~~

~~Key changes addressed in this revision include:~~

- ~~Replacing interpretation with clarification and expanding the Clarification Section narrative into process steps and including an associated flowchart~~
- ~~Creating separate sections for: 1) Withdrawal of a Regional Standard Pending Approval; 2) Retirement of an Approved NPCC Regional Standard; and 3) Approval of Process Waiver; 4) Process for Correcting Errata~~
- ~~Recognizing the new NPCC Cost Effectiveness Analysis Procedure (CEAP)~~
- ~~Identifying the Reliability Standard Audit Worksheet (RSAW) as a companion document to a regional standard that needs to be collaboratively developed by the drafting team and NPCC Compliance Staff~~
- ~~Creating three new appendices: 1) Appendix A: Regional Standard Authorization Request (RSAR) Completion Guidelines and Form; 2) Appendix B: Selection of drafting team Members and Nomination Form; and 3) Appendix C: Maintenance of Regional Standards and Process~~

~~In addressing areas for improvement in the NPCC Regional Reliability Standards Development Procedure, recent improvements made to the NERC Standards Process Manual (e.g., Standards Process Input Group (SPIG) recommendations) as well as the manuals of other Regional Entities were benchmarked to identify best practices for inclusion in this manual.~~

~~The process improvements and clarity captured in this revision to the NPCC Regional Reliability Standards Development Procedure, will result in a more timely and efficient manner to address the development of regional standards to ensure the reliability of the Bulk Electric System within the NPCC geographical area.~~

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II. INTRODUCTION

PURPOSE

This manual defines the characteristics of a Northeast Power Coordinating Council, Inc. (NPCC) regional Reliability Standard (hereinafter referred to as "regional standard") and establishes the process by which NPCC regional standards are developed, approved, revised, clarified and retired. The NPCC regional standards process is a stakeholder process that is approved by the NPCC members to ensure a transparent standard development process that is "open, fair, and inclusive."

NPCC regional standards address the reliability of the international and interconnected Bulk Electric System in Northeast North America. NPCC regional standards shall enable or support one or more NERC/ERO reliability principles[1] and will, in all cases, not be inconsistent with or less stringent than any requirements of the North American Electric Reliability Council/Electric Reliability Organization (NERC/ERO) continent-wide Reliability Standards.

The development of NPCC regional standards is performed according to the following principles using the process contained in this manual:

- Developed in a fair and open process that provides an opportunity for all interested parties to participate;
- Does not have an adverse impact on commerce that is not necessary for reliability;
- Provides a level of Bulk Electric System reliability that is adequate to protect public health, safety, welfare, and national security and would not have a significant adverse impact on reliability; and
- Based on a justifiable difference between Regions or between sub-Regions within the Regional geographic area.

Following industry approval, NPCC regional standards process and NPCC regional standards require approval by the NPCC Board of Directors, NERC as the Electric Reliability Organization (ERO) and the applicable regulatory authorities in the United States (FERC) and Canada.

BACKGROUND

Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and improving the reliability of the international, interconnected Bulk Electric System in Northeastern North America. NPCC carries out its mission through (i) the development of regional standards and compliance assessment and enforcement of continent-wide and regional standards, coordination of system planning, design and operations, and assessment of reliability, (collectively, "Regional Entity activities"), and (ii) the establishment of regionally-specific criteria, and monitoring and enforcement of compliance with such criteria (collectively, "criteria services activities").

The Energy Policy Act (EPA) of 2005 (Section 1211) amended the Federal Power Act (FPA) by adding Section 215, Electric Reliability. ~~——~~Specifically regarding standards development and pursuant with Section 215(e)(4) of the FPA, NPCC as a Regional Entity with delegated authority from NERC may propose regional standards to NERC for eventual enforcement within the NPCC region.

[1] Reliability Principles are available on the NERC website as amended from time to time. ~~Link: -~~ https://www.nerc.com/pa/Stand/Resources/Documents/Reliability_Principles.pdf#search=~~reliability%20Principles~~

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As a condition of NPCC membership, NPCC General and Full Members[2] agree to adhere to NERC Reliability Standards. NERC Reliability Standards are comprised of both continent-wide and regional standards. The NPCC regional standards apply only to that part of the Eastern Interconnection within the NPCC geographical area.

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III. Regional Standard Characteristics and Elements

1. Characteristic Attributes

The NPCC regional standards development process has the following key characteristics:

- **Fair- due -process** — The NPCC regional standards development process provides for reasonable notice and opportunity for public comment. At a minimum, the procedure shall include public notice of the intent to develop a standard, a public comment period on the proposed standard, due consideration of those public comments, and a ballot of interested stakeholders. Upon approval by the NPCC Members, the NPCC Board of Directors then votes to approve submittal of the regional standard to NERC for ERO approval, followed by submission to FERC and Canadian Authorities for their approvals.
- **Openness** — Participation in the NPCC regional standards development process is open to all persons and organizations that are directly and materially affected by the reliability of the NPCC's Bulk Electric System. There is no undue financial burden to participation. Participation shall not be conditioned upon membership in the ERO, NPCC or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.
- **Inclusive** — Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the reliability of NPCC's Bulk Electric System has the right to participate by: (a) expressing an opinion and its basis; (b) having their position considered, and (c) having the right to appeal a response through an established appeal process.
- **Balanced** — The NPCC regional standards development process strives to have an appropriate balance of interest and shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter. Pursuant with the NPCC By-Laws[3] there are seven (7) stakeholder voting sectors and the votes for each sector are weighted to achieve an appropriate balance.
- **Transparent** — All actions material to the development of NPCC regional standards are transparent and information regarding the progress of a standard's development action is made available to the public through postings on the NPCC website as well as through E-mail lists.
- **Without undue delay** — The NPCC regional standards development process shall be performed within a reasonable time.

~~In as much as NPCC is one of six Regional Entities within the Eastern Interconnection of North America, there will be no presumption of validity by the ERO for any NPCC regional standard.~~

[2] As defined in the NPCC By-Laws – available on the NPCC website

[3] NPCC By-Laws are available at this link~~on the NPCC By-Laws~~

Commented [HS3]: Do we need both footnotes here? If we have them the links should be live links.

In order to receive the approval of the ERO, the NPCC regional standards development process must also achieve the following objectives:

- **No Adverse Impact on Reliability of the Interconnection** — An NPCC regional standard provides an Adequate Level of Reliability[4] as defined by NERC.
- **Justifiable Difference** — An NPCC regional standard addresses a justifiable difference within the NPCC geographical area that results from a physical difference[5] or operating difference in the Northeast's Bulk Electric System. Although a justifiable difference allows for a unique regional standard, an NPCC regional standard shall be no less stringent than a continent-wide standard covering the same reliability risks.
- **Uniformity** — To the extent possible, the NPCC regional standards provides uniformity with Reliability Standards across the interconnected Bulk Electric System of North America.
- **No Undue Adverse Impact on Commerce** — An NPCC regional standard will not cause any undue adverse impact on business activities that are not necessary for reliability of the power system in the Region and ~~its~~ neighboring Interconnections~~interconnected Regions~~. All regional standards shall be consistent with NERC's market principles[6].

2. Elements of a Regional Standard

To ensure uniformity of regional standards and avoid inconsistency with NERC continent-wide standards, an NPCC regional standard shall be consistent with the elements identified in this section of the procedure. These elements are intended to apply a systematic discipline in the development and revision of regional standards. The application of a systematic discipline is necessary for implementing~~achieving~~ regional standards that are measurable, enforceable, and consistent as well as results oriented[7], i.e.:

- Performance-based,
- Risk-based, and
- Capability-based.

Types of Reliability Requirements

Regional reliability standards should be viewed as a portfolio of requirements designed to achieve 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 specific reliability objective or outcome that has a direct, observable effect on the reliability of the Bulk Electric System, i.e. an effect that can be measured using power system data or trends.

[4] Adequate Level of Reliability is available on the NERC website as amended from time to time

[5] The meaning of the phrase "physical difference" will be consistent with FERC's Order, issued September 22, 2004, Granting Request For Clarification regarding Docket No. PL04-5-000, Policy Statement on Matters Related to Bulk Power System Reliability.

[6] Market Principles are available on the NERC website as amended from time to time Link https://www.nerc.com/pa/Stand/Resources/Documents/Market_Principles.pdf#search=market%20principles

[7] ~~For~~ Results-based Standards see http://www.nerc.com/pa/Stand/Resources/Documents/ResultsBasedStandardGuidance.pdf

b) **Risk-based** - defines actions of registered entities that reduce a stated risk to the reliability of the Bulk Electric System and can be measured by evaluating a ~~particular product or outcome~~ result~~ing~~ from the mandatory requirements.~~required actions~~.

c) **Capability-based** - defines registered entity capabilities needed to perform reliability functions and can be measured by demonstrating that the capability exists within the entity as required.

Each regional standard shall enable or- ~~support one~~support one ~~or more~~or more ~~of the~~of the reliability principles[8] ~~as~~[8] ~~a~~ identified in the most recent set posted on the NERC website. Each regional standard shall also be consistent with all of the reliability principles. The intent of the set of NPCC regional standards is to deliver an Adequate Level of Reliability[98] as defined by NERC.

Recognizing that Bulk Electric System reliability and electricity markets are inseparable and mutually interdependent, all regional standards shall be consistent with the most recent set of Market Principles[109] as posted on the NERC website. Consideration of the Market Principles is intended to ensure that regional standards are written such that they achieve their reliability objective without placing undue restrictions or causing adverse impacts on competitive electricity markets.

ELEMENTS OF A REGIONAL STANDARD

A regional 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 Electric System. The components of an NPCC regional standard identified below are based on the NERC Standard Processes Manual (SPM) that was effective ~~approved by the NERC Board of Trustees at its~~on March 1, 2019 ~~February 2013 meeting~~. Future revisions of the NERC SPM will be used to provide guidance at the time of development of an NPCC regional standard if different from the elements listed below and not covered in this Manual.

The only mandatory and enforceable components of a regional standard are the: (1) Applicability, (2) Requirements, and (3) the Effective Dates. The additional components are included in the regional standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to ~~functional entities~~Registered Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.

The components of a regional standard may include the following:

Title:	A brief, descriptive phrase identifying the topic of the regional standard.
Number:	~~A unique~~A ~~identification~~unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the regional standards.
Purpose:	The reliability outcome achieved through compliance with the requirements of the regional standard.
Applicability:	Identifies which entities are assigned reliability requirements; i.e., the specific functional entities and facilities to which the regional standard applies.
Effective Dates:	Identification of the date or pre-conditions determining when each Requirement becomes effective in each jurisdiction.

[8] ~~Reliability Principles are available on the NERC website as amended from time to time~~

[89] Adequate Level of Reliability is available on the NERC website as amended from time to time Link: https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Information

al_Filing_Definition_Adequate_Level_Reliability_20130510.pdf
[109] Market Principles are available on the NERC website as amended from time to time

Requirement: An explicit statement that identifies the functional entity responsible, the action or result ~~outcome~~ that must be achieved, any conditions necessary to achieving the result~~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 compliance monitoring and enforcement responsibilities.

Measure: Provides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement.

Violation Risk Factors and Violation Severity Levels: Violation risk factors (VRFs) and violation severity levels (VSLs) are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved Reliability Standard. Each requirement in each Reliability Standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NPCC Standards Staff and Compliance Staff, at the same time as the associated Reliability Standard, but are not part of the Reliability Standard. The Board of Directors 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.
- Violation Severity Levels
  VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria.

Version History: The version history is provided for informational purposes and lists information regarding prior versions of the regional standard.

Variance: As applied to an NPCC regional standard is a Requirement (to be applied in the place of the NPCC region-wide Requirement) that is applicable to a specific geographic area or to a specific set of Registered Entities.

Compliance Enforcement Authority (CEA): The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated regional standard. The Compliance Enforcement Authority will be NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the ERO regional standards.

Reliability Standard Audit Worksheets (RSAWs)[~~1~~10] Reliability Standard Audit Worksheets (RSAWs) are developed as companion documents to regional and continent-wide Reliability Standards to facilitate the CEA assessment of a registered entity's compliance with a standard.

[~~1~~10] While RSAWs are not part of the regional standard, they are developed through collaboration of the drafting team and NPCC Compliance Staff.

~~Informational Elements: Elements to aid in the implementation of the regional standard.~~

Supplemental Material: ~~***Application Guidelines:***~~ Information to aid in the implementation of the regional standard~~Guidelines or reference documents to support the implementation of the associated regional standard~~.

~~***Procedures:*** Procedures to support implementation of the associated regional standard.~~

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IV. REGIONAL STANDARDS DEVELOPMENT PROCESS

1. ROLES IN THE NPCC REGIONAL STANDARD PROCESS

NOMINATION, REVISION, CLARIFICATION, OR RETIREMENT OF A STANDARD:

Any member of NPCC or group within the NPCC region shall be allowed to request that an NPCC regional standard be developed, modified, clarified, or retired. Additionally, any person (organization, company, government agency, individual, etc.) who is directly and materially affected by the reliability of the NPCC Bulk Electric System shall be allowed to request that an NPCC regional standard be developed, modified, clarified, or retired. The following section identifies the process roles in the NPCC regional standards process. Refer to Step 2 STANDARD DEVELOPMENT PROCESS STEPS and FIGURE 1: FLOWCHART OF REGIONAL STANDARDS DEVELOPMENT PROCESS OVERVIEW for the regional standards development process steps and associated flowchart. Refer to Step 3 STANDARD CLARIFICATION PROCESS STEPS and FIGURE 2: FLOWCHART OF REGIONAL STANDARDS CLARIFICATION PROCESS OVERVIEW for the regional standards clarification process steps and associated flowchart.

PROCESS ROLES AND RESPONSIBILITIES

BOARD OF DIRECTORS

The NPCC Board of Directors (Board) shall consider for adoption regional standards, definitions, variances and clarifications and associated implementation plans that have been processed according to the processes identified in this manual.

DRAFTING TEAM

The drafting team (DT) should strive to achieve a portfolio of performance, risk, and capability-based mandatory reliability requirements that support an effective defense-in-depth strategy. The drafting team develops standards-related regional products as directed by the NPCC RSC and within the scope of an approved Regional Standard Authorization Request (RSAR) or a Clarification Request (CR). The product that is developed is typically a new or revised regional standard, but could also be a definition, a reference document, a set of Violation Risk Factors, a set of Violation Severity levels, or the team could be appointed to assist an author in refining a Regional Standard Authorization Request (RSAR). The drafting team also works collaboratively with NPCC Compliance Staff to develop Reliability Standard Audit Worksheets (RSAWs) at the same time regional standards are developed. The drafting team shall remain in place until such time as the NERC Board of Trustees adopts the regional standard.

MANAGER OF RELIABILITY STANDARDS

The NPCC Manager of Reliability Standards has the overall responsibility for managing the NPCC regional standards processes in accordance with this manual. As used herein, the NPCC Manager of Reliability Standards will be the NPCC Manager of Reliability Standards or his/her designee.

NPCC MEMBERS

NPCC members may participate in the comment and ballot periods associated with the development and industry approval of regional standards. The ballot body is comprised of all

entities or individuals that qualify for one of the stakeholder sectors within NPCC as stated in the most recently approved NPCC Bylaws. All General and Full Members of NPCC can participate in the balloting of regional standards. Any entity or person, including non-NPCC members, may submit comments during the open process comment periods for standards.

NON-NPCC MEMBERS

Any entity or person that is neither a General nor Full Member of NPCC is not eligible to participate in the ballot body voting on a regional standard. However, any entity or person, including non-NPCC members, may submit comments during the open process comment periods for standards. Subject Matter Experts (SMEs), regardless of NPCC membership status, are encouraged to participate in comment periods for regional standards.

NPCC STANDARDS STAFF

The Standards Staff is responsible for assisting the NPCC Manager of Reliability Standards and the RSC in administering the NPCC regional standards processes in accordance with this manual.

NPCC COMMITTEES, TASK FORCES AND WORKING GROUPS

The Committees, Task Forces and Working Groups within NPCC serve an active role in the standards process. —Activities performed by these groups include, but are not limited to, the following:

- Identify the need for new or modified regional standards
- Initiate NPCC Standards actions by developing Regional Standard Authorization Requests (RSARs)
- Develop comments (views and objections and suggestions) to standards actions
- Participate in NPCC Standard drafting
- Dispensation of Clarification Requests (CRs)
- Provide technical oversight in response to changing industry conditions and ERO Requirements
- Conduct Field Tests, as required

REGIONAL STANDARDS COMMITTEE ~~(RSC)~~

The NPCC Regional Standards Committee (RSC), a committee of the NPCC Board of Directors, is charged with oversight of all drafting team activities and managing the NPCC regional standards development process in accordance with this manual.

The RSC is responsible for maintenance of the Regional Standard Processes Manual (RSPM), including the endorsement of RSPM revisions for NPCC Board review and approval.

RELIABILITY COORDINATING COMMITTEE ~~(RCC)~~

The Reliability Coordinating Committee (RCC) supports the standards development process through the assignment of NPCC Task Forces to serve as technical resources for: (1) staffing drafting teams, and (2) performing a technical advisory role in the regional standards process through comments, recommendations and technical justifications.

REQUESTER

Any individual representing an organization (entity, company, government agency, etc.) that is directly and materially affected by the reliability of the Bulk Electric System within the NPCC

geographical area may request a regional standard be developed or an existing regional standard be modified, clarified, or deleted.

QUALITY REVIEW TEAM

The NPCC Standards Staff shall coordinate a quality review of the "final draft" of the regional standard, implementation plan, VRFs and VSLs, and associated documents to assess whether the documents are within the scope of the associated RSAR, whether the regional standard is clear and enforceable as written and the VRFs and VSLs are developed according to NERC and FERC guidelines. The Quality Review Team may be comprised of legal and compliance representatives, a technical writer, and NPCC Standards Staff. ~~It will not involve individuals who participated on the drafting team of the standard undergoing the Quality Review.~~

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2. STANDARD DEVELOPMENT PROCESS STEPS

STEP 2.1: REGIONAL STANDARDS AUTHORIZATION REQUEST TO DEVELOP, MODIFY OR RETIRE

A Regional Standard Authorization Request[1] (RSAR) is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified regional standards or the benefit of retiring one or more approved regional standards.

An RSAR shall be used to seek approval and initiate the development, modification or retirement of an NPCC regional standard. An RSAR is not used to seek a Clarification Request (CR) of an NPCC regional standard. The initiation and handling of a CR is covered in Step 3 STANDARD CLARIFICATION PROCESS STEPS, of this manual.

Any individual representing an organization which is directly or materially impacted by the operation of the Bulk Electric System within the geographical footprint of NPCC may request, via a submittal of an RSAR to the NPCC Manager of Reliability Standards, the development, modification, or deletion of an NPCC regional standard. The individual completing the form is referred to herein as the Requester.

STEP 2.1.A. REQUESTER ACTIONS

Note:	*The NPCC Manager of Reliability Standards will assist the Requester, as necessary, to ensure all required information is submitted on the RSAR.*

The Requester shall complete an RSAR form in accordance with the guidance provided in APPENDIX A: RSAR COMPLETION GUIDELINES.

The Requester shall submit the completed RSAR to the NPCC Manager of Reliability Standards, via npccstandard@npcc.org, for processing.

STEP 2.1.B. NPCC MANAGER OF RELIABILITY STANDARDS ACTIONS

The NPCC Manager of Reliability Standards shall review the submitted RSAR and verify that the submitted form has been adequately completed. Within fifteen (15) calendar days[2] of receipt of the submitted RSAR, the NPCC Manager of Reliability Standards will electronically acknowledge

[1] The RSAR is located on the NPCC website under Standards – Regional Standards General

[2] Time periods specified in this manual may be extended as deemed appropriate by NPCC Staff. When business days are specified, this provision could be used to take into account differing Canadian and US holiday schedules. When calendar days are specified, this provision could be used to take into account due dates that fall on a weekend.

receipt of the RSAR. If, at that time, the NPCC Manager of Reliability Standards finds the RSAR to be deficient, the Requester will be contacted to determine how to proceed.

Within ten (10) calendar days of the receipt of an adequately completed RSAR, the NPCC Manager of Reliability Standards shall forward the ~~properly completed~~ RSAR to the NPCC Regional Standards Committee (RSC) for its review and processing. Included in the transmittal of the RSAR to the RSC, the NPCC Manager of Reliability Standards shall include a statement indicating the applicability of the NPCC Cost Effectiveness Analysis Procedure (CEAP) for the proposed change.

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STEP 2.1.C. NPCC REGIONAL STANDARDS COMMITTEE (RSC) ACTIONS

Note: The RSC shall meet to review all pending RSARs. The frequency of this review process will depend on workload, but in no case shall a ~~properly completed~~[1] RSAR wait for RSC action more than 60 calendar days from the date of receipt by the RSC.

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Or just a reference to Appendix A where the RSAR instructions reside.

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The RSC shall review the RSAR and take one of the following actions:

- Remand the RSAR back to the NPCC Manager of Reliability Standards for additional work. In this case, the NPCC Manager of Reliability Standards shall work with the Requester to provide additional information or clarification for the RSAR as specified by the RSC.
- Reject the RSAR. In this case, the RSC will provide its determination to the NPCC Manager of Reliability Standards, who will then provide a written explanation for rejection to the Requester within ten (10) calendar days of the rejection decision.

Note: Before the RSC can accept an RSAR for a new or modified standard the applicable CEAP process steps shall be completed.

- Accept the RSAR.
  - If a new or modified standard has been authorized, within ten (10) calendar days of the authorization the NPCC Manager of Reliability Standards shall: 1) post notification on the NPCC website of the intent to develop or modify a regional standard; 2) notify the ERO for processing in accordance with its process, as applicable; and 3) notify the Requester of the acceptance of the RSAR.
  - If the retirement of an existing regional standard has been authorized, within ten (10) calendar days of the authorization the NPCC Manager of Reliability Standards shall: 1) post notification on the NPCC website of the intent to retire an existing regional standard; 2) notify the ERO for processing in accordance with its process, as applicable; and 3) notify the Requester of the acceptance of the RSAR. The process to retire an existing regional standard is included in Step 6 RETIREMENT OF AN APPROVED NPCC REGIONAL STANDARD.

STEP 2.2: FORMATION OF DRAFTING TEAM FOR NEW OR MODIFIED STANDARD

An RSAR that has been accepted by the RSC shall, within ten (10) calendar days of the acceptance of the RSAR, be submitted by the NPCC Manager of Reliability Standards to the NPCC Reliability Coordinating Committee (RCC). The RCC shall, within sixty (60) calendar days, assign the development of the regional standard to an NPCC Task Force, and notify the NPCC Manager of Reliability Standards of its decision within ten (10) calendar days.

Commented [HS8]: What if there is no Task Force with the requisite scope or skills for a regional standard? I am thinking of DER here. Should there be an ability to create a Task force specifically for the purpose?

Commented [JMW(9R8]: I'm thinking if the RCC wanted to create a new task force they could do it. The issue does not really need to be addressed in the Standard Process Manual

[1] ~~A properly completed RSAR is one which has fulfilled all the expectations outlined in Appendix A~~

After receipt of the notification of drafting team assignment, the NPCC Manager of Reliability ~~Standards shall~~Standards shall oversee solicitation and recommendation of a list of additional qualified [1][3][4] candidates over and above the appropriate NPCC Task Force members, for appointment to the drafting team. The Requester and an NPCC Compliance Staff person will be included on the drafting team. Within sixty (60) calendar days of the drafting team assignment notification from the RCC, the NPCC Manager of Reliability Standards shall submit the list of the entire drafting team membership to the RSC for acceptance. The RSC may accept the recommendations of the NPCC Manager of Reliability Standards as presented or revise the recommendations as necessary.

Upon acceptance of the drafting team slate, the RSC shall provide a target date on which the drafting team is expected to have ready a completed draft regional standard and associated supporting documentation available for consideration by the NPCC membership. Additionally, the RSC shall provide the drafting team with any preliminary development products including, but not limited to, a draft standard, comments, and related white papers.

The RSC shall designate one of its members to actively monitor and assist NPCC staff in the oversight of drafting team milestones and deadlines, and extend or expedite milestones and deadlines, as appropriate, acting as a liaison between the drafting team and the RSC to help resolving any issues.

STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD AND ASSOCIATED DOCUMENTS

Prior to beginning work on the development of a new or revised regional standard and the associated supporting documentation, the drafting team should develop a work plan for completing the regional standard development work, including the establishment of milestones for completing critical elements of the work in sufficient detail to ensure that the drafting team will meet the target date established by the RSC, or the drafting team shall propose an alternative date. This work plan must be submitted to the RSC for its concurrence. When a drafting team begins its work, it shall regularly (at least quarterly) report progress against that aforementioned work plan to the NPCC Manager of Reliability Standards for presentation to the RSC.

> *Note: During the regional standards development, the drafting team will deliberate on whether the requirements in the regional standard are ~~developed enough~~ adequate for the purpose off~~to begin~~ the Cost Effectiveness Analysis (CEA) and the ~~of the~~ NPCC Cost Effectiveness Analysis Procedure (CEAP). When appropriate, the drafting team shall request that the RSC initiate the second phase (CEA) of the CEAP process.*

The drafting team shall create and manage its work structure (e.g., sub-teams) and meeting schedule (face-to-face as well as electronic meetings), as necessary, to meet the milestone dates and project deliverables outlined in the work plan.

The work products of the drafting team should consist of the following

- A draft regional standard consistent with the RSAR on which it was based
- An implementation plan, including the nature, extent and duration of field-testing, if any
- Identification of any existing regional standard and NPCC criteria that will be deleted, in part or whole, or otherwise impacted by the implementation of the draft regional standard

[1][3][4] Refer to Appendix B: Selection of Drafting Team Members

- Technical reports, white papers and/or work papers that provide technical justification for the draft regional standard under consideration
- Reliability Standard Audit Worksheet (RSAW) collaboratively developed by the drafting team and NPCC Compliance Staff

Any proposed changes to definitions in existing regional standards should be sent to the appropriate Task Force (TF) for consideration of the impact to the standard. If necessary, the TF can produce an RSAR.

NPCC Standards Staff can assist in the drafting of the regional standard including compliance measures, process and elements. The drafting of measures and compliance administration aspects of the standard will be coordinated with the NPCC Compliance Staff.

The drafting team shall submit the initial and subsequent interim drafts of the regional standard and associated documents to the NPCC Manager of Reliability Standards to obtain RSC concurrence to post documents for comment.

STEP 2.4: POSTING FOR COMMENT PERIOD AND RESOLUTION OF COMMENTS

Note:	*There are no limits to the number of public comment periods and ballots that can be conducted to result in a regional standard that is clear and enforceable, and achieves a quorum and sufficient affirmative votes for approval.*

STEP 2.4.A. COMMENT PERIOD

Note:	*For Final Comment Period skip this step and proceed to* STEP 2.4.B. FINAL COMMENT PERIOD.

As authorized by the RSC, the NPCC Manager of Reliability Standards shall post the draft of the regional standard on the NPCC website, along with a draft implementation plan and available supporting documents, for a forty-five (45) calendar day comment period~~. The NPCC Manager of Reliability Standards shall also notify NERC to process the draft document in accordance with NERC's regional standards review procedure, as applicable.~~

Commented [JMW(10]: It may not be necessary to notify NERC.

Following the conclusion of the NPCC comment period, the NPCC Manager of Reliability Standards will assemble the comments on the draft regional standard and associated documents and provide all comments to the drafting team for consideration.

Within thirty (30) calendar days of the conclusion of the comment period the drafting team shall convene and consider changes to the draft Standard, the implementation plan and/or supporting technical documents based upon comments received. All submitted comments shall be addressed, and each commenter shall be advised of the disposition, with reasons, of their comments. The NPCC Manager of Reliability Standards shall publicly post all of the drafting team's responses to stakeholder comments on the NPCC website.

Based on the comments received, the drafting team may elect to:

- Return to STEP 2.3: ~~DEVELOPMENT OF A REGIONAL STANDARD AND~~ DEVELOPMENT OF A REGIONAL STANDARD AND ASSOCIATED DOCUMENTS to revise the draft regional standard, the implementation plan and/or supporting technical documents.
- Recommend that the RSC authorize Field Testing of the draft regional standard. Upon completion of the Field Test, return to STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD

AND ASSOCIATED DOCUMENTS to revise the draft regional standard based on insights learned during the Field Test.

- Obtain RSC concurrence to post documents for Final Comment Period and request that the RSC initiate the second phase (CEA) of the CEAP process

STEP 2.4.B. FINAL COMMENT PERIOD

The NPCC Standards Staff shall coordinate a Quality Review of "final draft" of the regional standard, implementation plan, VRFs and VSLs, and associated documents to assess whether the documents are within the scope of the associated RSAR, whether the regional standard is clear and enforceable as written and the VRFs and VSLs are developed according to NERC and FERC guidelines. Upon Completion of the Quality Review, including resolution of comments, the drafting team shall submit the regional standard to the NPCC Manager of Reliability Standards to obtain RSC concurrence to post these documents for comment.

As authorized by the RSC, the NPCC Standards Staff shall post the "final draft" of the regional standard on the NPCC website, along with the implementation plan, supporting documents and the Cost Effectiveness Analysis (CEA) survey[145] for a forty-five (45) calendar day comment period. ~~NPCC Standards Staff shall also notify NERC to process the proposed final document in accordance with NERC's regional standards review procedure, as applicable.~~

Commented [JMW(11)]: It may not be necessary to notify NERC.

Following the conclusion of the NPCC comment period, the NPCC Manager of Reliability Standards will assemble the comments on the posted regional standard and associated documents and provide all comments to the drafting team for consideration.

In addition, the RSC, pursuant with the requirements of the Cost Effectiveness Analysis Procedure (CEAP), will use the responses to the posted CEA survey to develop a recommendation based on the cost effectiveness of the proposed regional standard.

The NPCC Task Forces (TFs) or Working Groups (WGs) may develop recommendations for submittal to the RSC. Following the RSC deliberations to determine a course of action, the RSC will communicate to the drafting team to:

- Return to STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD AND ASSOCIATED DOCUMENTS to revise the Standard to address the results of the CEAP
- Accept the Standard "as is" to move forward through the remainder of the process
- Hold the Standard in abeyance until such time as additional guidance can be provided regarding whether or how to continue
- Decide not to pursue the development of certain requirements or the entire Standard due to cost effectiveness considerations

Upon Completion of the final comment period the drafting team shall submit the proposed regional standard, along with any supporting materials, consideration of comments and field test results, to the NPCC Manager of Reliability Standards to obtain RSC concurrence to post the regional standard for ballot and concurrently provide an information copy to the RCC.

[145] In accordance to the Cost Effectiveness Analysis Procedure (CEAP) the Cost Effectiveness Analysis (CEA) survey may be assigned directly to NPCC Task Forces (TFs) or Working Groups (WGs) in addition to the posting process.

The NPCC Manager of Reliability Standards shall also publicly post all of the drafting team's responses to stakeholder comments on the NPCC website.

STEP 2.5: POSTING FOR BALLOT PERIOD IN THE OPEN PROCESS

~~*Note: There are no limits to the number of public comment periods and ballots that can be conducted to result in a regional standard that is clear and enforceable, and achieves a quorum and sufficient affirmative votes for approval.*~~

As authorized by the RSC, the NPCC Manager of Reliability Standards shall post the proposed regional standard on the NPCC website, along with supporting documentation [1][56] (e.g., implementation plan, consideration of comments, technical reports, white papers and any field test results), for a thirty (30) day pre-ballot review period and a subsequent ten (10) day ballot period. The ten (10) day ballot period will commence immediately following the pre-ballot review period. In the event that a quorum exists for purposes of an electronic vote but the ballot purpose has not been resolved, NPCC may continue to solicit additional responses in order to resolve the matter by electronic voting. In the event that quorum has not been achieved for purposes of an electronic vote, NPCC may continue to solicit electronic ballots, including abstentions, to obtain quorum and resolve the matter.

~~At the time the regional standard is posted for ballot, the NPCC Manager of Reliability Standards shall also notify NERC to process the proposed regional standard in accordance with NERC's regional standards review procedure, as applicable.~~

During the ballot period, the NPCC Members of the ballot body can cast their vote as follows:

- Affirmative, with or without comments
- Negative with comments
- Abstain

In accordance with the NPCC Bylaws, a quorum and receipt of a two-thirds (2/3) affirmative majority of the weighted sector votes is required for a ballot to pass.

The NPCC Manager of Reliability Standards shall post the final outcome of the ballot process on the NPCC website.

STEP 2.5.A. BALLOT DOES NOT RECEIVE 2/3 AFFIRMATIVE VOTE

If a ballot fails to achieve the 2/3 majority vote the NPCC Manager of Reliability Standards may:

- Direct the drafting team to respond to ballot comments and return to STEP 2.5: POSTING FOR BALLOT PERIOD IN THE OPEN PROCESS to re-ballot the regional standard. The consideration of comments from prior ballot will be included with the re-posting.
- Return to STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD AND ASSOCIATED DOCUMENTS to revise the regional standard to address the comments received.
- Pursue the discontinuance of the regional standard development by soliciting the Requester to withdraw the RSAR or by soliciting the RSC to reject the RSAR pursuant with STEP 2.1.C. NPCC REGIONAL STANDARDS COMMITTEE (RSC) ACTIONS. The NPCC Manager of

[1][56] The ballot posting is for the regional standard, definition, variance or clarification. Supporting documentation is included for information only and is not balloted.

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Commented [JMW(14]: It may not be necessary to notify NERC.

Reliability Standards, in the event of a discontinuance of the development of a regional standard, shall post a notice of the discontinuance and will post and archive all comments submitted during the process for future consideration, if required. ~~The NPCC Manager of Reliability Standards will also notify NERC to process the proposed regional standard in accordance with NERC's regional standards review procedure, as applicable.~~.

Commented [JMW(15]: It may not be necessary to notify NERC.

STEP 2.5.B. BALLOT RECEIVES ≥ TWO-THIRDS (2/3) AFFIRMATIVE VOTE

A ballot that achieved two-thirds or greater affirmative vote has successfully passed. However, negative votes with comments should still be reconciled. If there is at least one negative vote with comments proceed to STEP– 2.5.B.1 APPROVED BALLOT WITH "NEGATIVE VOTE WITH COMMENT". If there was not any negative vote with comments proceed to STEP 2.5.B.2 APPROVED BALLOT WITHOUT "NEGATIVE VOTE WITH COMMENT".

STEP 2.5.B.1 APPROVED BALLOT WITH "NEGATIVE VOTE WITH COMMENT"

Following the conclusion of the NPCC ballot period, the NPCC Manager of Reliability Standards will assemble the comments on the posted regional standard and provide all comments to the drafting team for consideration. The drafting team shall review all negative votes with comments and elect to:

- Recommend to the RSC to accept the regional standard "as is" and seek RSC endorsement to move forward through the remainder of the process. Upon receiving RSC endorsement to proceed, the regional standard and associated documents, approved by the NPCC ballot body, shall be forwarded by the Assistant Vice President Standards to the NPCC Board of Directors for final Regional approval. If comments that were received during balloting should be considered in future revisions to the regional standard then the NPCC Manager of Reliability Standards should log comments in an issues database.
- Return- to STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD AND ASSOCIATED DOCUMENTS to revise the regional standard to address the comments received.
- Respond to ballot comments and recommend to the RSC endorse the return to STEP 2.5: POSTING FOR BALLOT PERIOD IN THE OPEN PROCESS to re-ballot the regional standard. The NPCC Manager of Reliability Standards should include the consideration of comments from the prior ballot with the re-posting.

STEP 2.5.B.2 APPROVED BALLOT WITHOUT "NEGATIVE VOTE WITH COMMENT"

Regional standard and associated documents, approved by the NPCC ballot body, shall be forwarded by the Assistant Vice President Standards to the NPCC Board of Directors for final Regional approval.

STEP 2.6: NPCC BOARD OF DIRECTORS APPROVAL

Following approval by the NPCC Members, regional standards require review and approval by the NPCC Board of Directors. The NPCC Board of Directors may take the following actions:

- Approve the regional standard as presented.
- Approve the regional standard with comments to incorporate non-substantive revisions. [The NPCC Board of Directors may not make substantive revisions to the standard.]
- Remand the regional standard back to the RSC and the drafting team to address their concerns. The RSC / drafting team can address the BOD comments and re-submit for BOD

approval or return to STEP 2.3: DEVELOPMENT OF A REGIONAL STANDARD AND ASSOCIATED DOCUMENTS to revise the regional standard to address the comments received.

STEP 2.7: NERC BOARD OF TRUSTEES SUBMITTAL

Upon approval by the NPCC Board of Directors, the NPCC Manager of Reliability Standards shall submit the regional standard to NERC, as the Electric Reliability Organization, for approval and subsequent filing with FERC and the applicable Canadian Provincial regulatory and/or governmental authorities for adoption.

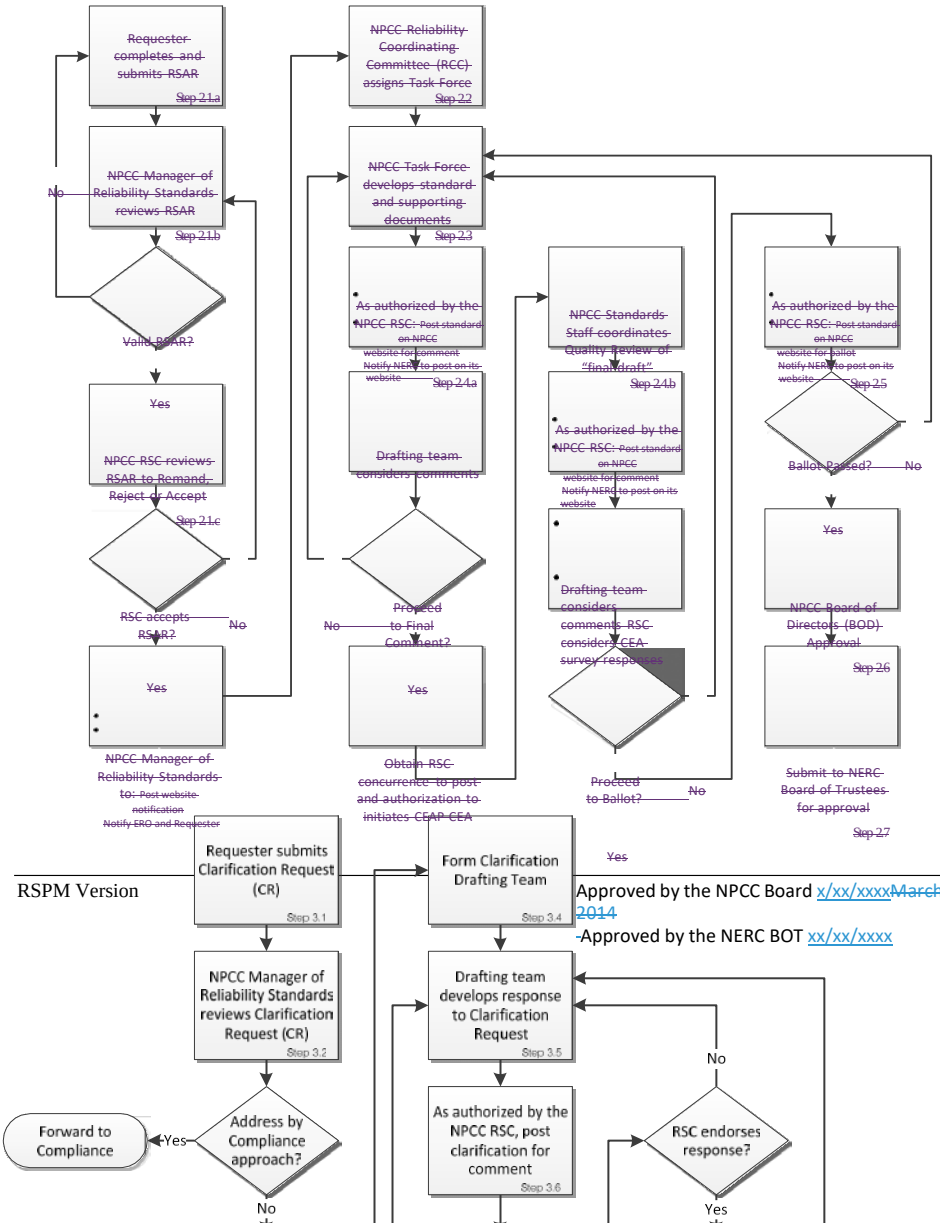
STEP 2.8: IMPLEMENTATION OF AN NPCC REGIONAL STANDARD

Following the approval of an NPCC regional standard by FERC and the applicable Canadian Provincial regulatory and/or governmental authorities, all applicable Registered Entities ~~users, owners, and operators of the Bulk Electric System~~ in the NPCC geographic area are required to comply with the standard as of its enforcement date.

~~ERO approved Reliability Standards (both continent-wide and regional) are included in both the NERC and NPCC Compliance Monitoring and Enforcement Programs (CMEPs).~~

Commented [JMW(16]: Compliance related. Not Standards Process Manual related. Also, Regional standards are not automatically included in the annual risk-based CMEP Implementation Plan.

FIGURE 1: FLOWCHART OF REGIONAL STANDARDS DEVELOPMENT PROCESS OVERVIEW



3. STANDARD CLARIFICATION PROCESS STEPS

This section applies to NPCC regional standards that have been approved[1] and are currently enforceable or have a future enforcement date. A clarification request is not permitted for regional standards under development. For regional standards under development, an explanation of a requirement or its meaning can be sought during a comment period. Refer to Step 2, STANDARD DEVELOPMENT PROCESS STEPS of this manual for details on the comment process for a standard under development.

STEP 3.1: REGIONAL STANDARDS CLARIFICATION REQUEST (CR)

Any member of NPCC or group within the NPCC region shall be allowed to submit a Clarification Request (CR) for an NPCC regional standard.

Additionally, any person (organization, company, government agency, individual, etc.) who is directly and materially affected by the reliability of the NPCC Bulk Electric System shall be allowed to submit a Clarification Request (CR) for an NPCC regional standard.

Note: A valid Clarification Request is one that seeks additional clarity about one or more requirements in an approved regional standard, but does not request approval as to how to comply with any requirements of the standard.

The Requester should submit a Clarification Request[2] (CR) for an NPCC regional standard directly to the NPCC Manager of Reliability Standards, via npccstandard@npcc.org, for processing. Alternatively, the Requester can submit a Request for Interpretation (RFI) of an NPCC regional standard under the NERC process for developing an interpretation[3] to the NERC Reliability Standards Staff explaining the clarification required, the specific circumstances surrounding the request, and the impact of not having the clarification provided. A copy of the completed RFI form should also be sent to the NPCC Manager of Reliability Standards.

NERC Reliability Standards Staff will refer the RFI to NPCC and delegate its resolution to NPCC. NPCC will process the NERC delegation pursuant with the NPCC Clarification Request (CR) process described herein.

STEP 3.2: REVIEW AND VALIDATION OF CLARIFICATION REQUEST (CR)

Upon receipt of a Clarification Request (CR) for an NPCC regional standard, the NPCC Manager of Reliability Standards shall review the CR to determine whether:

- It meets the requirements for a valid Clarification Request
- A compliance process or approach could be used in lieu of a clarification

The NPCC Manager of Reliability Standards will utilize, as necessary, the NPCC Standards Staff, NPCC Compliance and Legal Staffs when determining the validity of the CR. Based on this review, the NPCC Manager of Reliability Standards will recommend to the RSC whether to accept or reject the CR. The recommendation to the RSC should be made within thirty (30) calendar days of the receipt of the CR.

[1] Approval is granted by FERC and the Canadian Provincial regulatory and/or governmental authorities, as applicable.
[2] The NPCC Clarification Request form is included as Appendix D
[3] The *Request for Interpretation* form is posted under Resource Documents on the NERC Standards webpage.

The following examples identify situations that may warrant a recommendation from the NPCC Manager of Reliability Standards to reject the CR:

- Requests approval of a particular compliance approach
- Identifies a gap or perceived weakness in the approved regional standard (Requester should be redirected to initiate an RSAR rather than a CR)
- Where an issue can be addressed by an active (regional or continent-wide) standard drafting team
- Where an issue can be better addressed by a compliance process or approach
- Where it requests clarification of any element of a regional standard other than a requirement
- Where a question has already been addressed in the record
- Where the clarification identifies an issue and proposes the development of a new or modified regional or continent-wide standard (such issues should be addressed via submission of an RSAR or a SAR)
- Where a clarification seeks to expand the scope of a regional standard
- Where the requirement of the regional standard is clear

STEP 3.3: NPCC REGIONAL STANDARDS COMMITTEE (RSC) ACTIONS

The RSC shall review the CR along with the recommendation from the NPCC Manager of Reliability Standards and take one of the following actions:

- Reject the CR. In this case, the RSC will provide its determination to the NPCC Manager of Reliability Standards, who will then provide a written explanation for rejection to the CR to the entity requesting the clarification within ten (10) calendar days of the decision to reject.
- Accept the CR. In this case, the RSC will provide its determination to the NPCC Manager of Reliability Standards, who will then: 1) post notification on the NPCC website of the intent to develop a clarification; 2) notify the NPCC Reliability Coordinating Committee (RCC) of the need to assign the resolution of the CR to one or more Task Forces (if more than one Task Force is assigned, one of them shall be assigned the lead role); and 3) notify the Requester of the acceptance of the CR. The notifications shall be made within ten (10) calendar days of the acceptance of the CR.

STEP 3.4: FORMATION OF DRAFTING TEAM FOR RESPONSE TO CR

A CR that has been accepted by the RSC shall be assigned by the RCC to the responsible NPCC Task Force to make up the clarification drafting team (CDT) and develop the CR response.

STEP 3.5: DEVELOPMENT OF RESPONSE TO CR

> *Note: A valid clarification 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.*

Within sixty (60) calendar days from the receipt of being assigned to respond to a CR, the CDT shall submit a proposed clarification response to the NPCC Manager of Reliability Standards. Upon receipt of the proposed clarification response from the CDT, the NPCC Manager of

Reliability Standards shall present the response to the RSC to obtain concurrence to post the proposed response for comment.

Along with the proposed clarification response, the drafting team shall also develop and submit a set of questions to be included in the comment form, for approval by the RSC.

If the RSC concurrence is not received, the drafting team will continue to refine the clarification response.

Note: There are no limits to the number of public comment periods that can be conducted to result in a clear and concise clarification of a regional standard requirement.

STEP 3.6: POSTING CR FOR COMMENT PERIOD AND RESOLUTION OF COMMENTS

As authorized by the RSC, the NPCC Manager of Reliability Standards shall post the proposed clarification response on the NPCC website for a forty-five (45) calendar day comment period.

Following the conclusion of the NPCC comment period, the NPCC Manager of Reliability Standards will assemble the comments on the proposed clarification response and provide all comments to the drafting team for consideration.

Within thirty (30) calendar days of the conclusion of the comment period the drafting team shall convene and consider changes to the proposed clarification response based upon comments received. All submitted comments shall be addressed, which may be in the form of a summary response addressing each of the issues raised in comments received. The NPCC Manager of Reliability Standards shall publicly post all of the drafting team's responses to stakeholder comments on the NPCC website.

Based on the comments received, the drafting team may elect to:

- Return to STEP 3.5: DEVELOPMENT OF RESPONSE TO CR to revise the proposed clarification response.
- Accept the proposed clarification response "as is" to move forward through the remainder of the process.

Upon acceptance of the proposed clarification response "as is," the drafting team shall submit the proposed clarification response to the NPCC Manager of Reliability Standards to obtain RSC endorsement to the submitted CR response.

STEP 3.7: REGIONAL STANDARDS COMMITTEE APPROVAL OF CR

Upon receipt of the CR response from the NPCC Manager of Reliability Standards, the RSC shall elect to:

- Endorse the proposed clarification response and direct the NPCC Assistant Vice President Standards to forward the CR to the NPCC Board of Directors for final Regional approval; or
- Direct the drafting team to return to STEP 3.5: DEVELOPMENT OF RESPONSE TO CR to revise the proposed clarification response

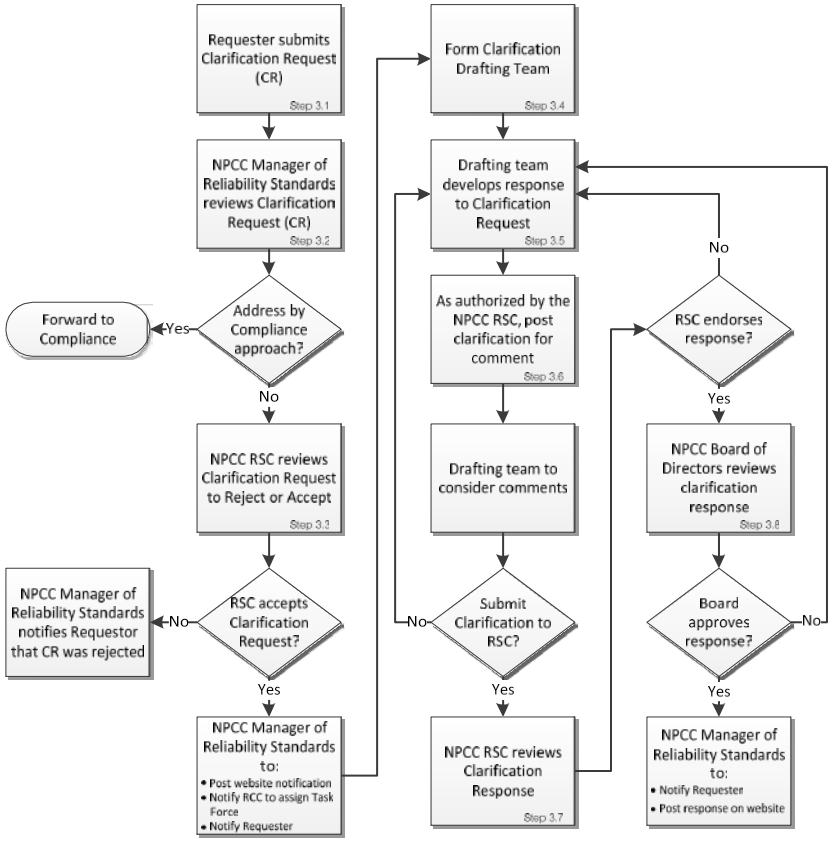
STEP 3.8: NPCC BOARD OF DIRECTORS APPROVAL OF CR

Following endorsement by the RSC, clarification responses require review and approval by the NPCC Board of Directors. The NPCC Board of Directors may take the following actions:

- Approve the clarification response as presented
- Approve the clarification response with comments to incorporate non-substantive revisions. [The NPCC Board of Directors may not make substantive revisions to the clarification response.]
- Remand the clarification response back to the RSC and the drafting team to address their concerns

Upon receipt of Board approval, the NPCC Manager of Reliability Standards shall notify the Requestor and post the approved clarification on the NPCC website.

FIGURE 2: FLOWCHART OF REGIONAL STANDARDS CLARIFICATION PROCESS OVERVIEW



4. DISCONTINUANCE OF REGIONAL STANDARD DEVELOPMENT

The term "discontinuance" as used herein refers to terminating the standard development process after RSAR approval but prior to posting a regional standard for industry ballot. From time to time the need or rationale for a regional standard may change thereby necessitating the curtailment

of the regional standard development. Upon notification or determination that a regional standard under development should be considered for discontinuance due to a perceived change in the need for the standard, the NPCC Manager of Reliability Standards will submit the recommendation for discontinuance to the RSC for approval.

5. WITHDRAWAL OF A REGIONAL STANDARD PENDING APPROVAL

The term "withdrawal" as used herein, refers to the revocation of a request for approval of a regional standard, variance, clarification or definition that has been approved by the NPCC Board of Directors and has not been filed with Applicable Governmental Authorities or has been filed but not yet approved by Applicable Governmental Authorities. The RSC may withdraw a regional standard, variance, clarification or definition for good cause subject to approval by the NPCC Board of Directors. Upon approval by the NPCC Board of Directors, the NPCC Manager of Reliability Standards will notify NERC Staff to petition the Applicable Governmental Authorities, as necessary, to allow for withdrawal in the case that the regional standard has been filed.

6. RETIREMENT OF AN APPROVED NPCC REGIONAL STANDARD

The term "retirement" refers to the discontinuation of a regional standard in whole, certain requirements within a regional standard, a variance, clarification or definition that: 1) has been approved by Applicable Governmental Authorities and 2) is not being superseded by or merged into a new or revised regional standard, clarification or definition.

Upon identification of a need for retirement, an RSAR containing the proposal of the retirement will be handled in accordance with the STEP 2.1: REGIONAL STANDARDS AUTHORIZATION REQUEST TO DEVELOP, MODIFY OR RETIRE. The proposal shall include the rationale for the retirement and a statement regarding the impact of retirement on the reliability of the Bulk Electric System. Upon approval by the NPCC Members and the NPCC Board of Directors, the NPCC Manager of Reliability Standards shall submit the request for retirement to NERC, as the Electric Reliability Organization, for approval and to subsequently petition the Applicable Governmental Authorities to allow for retirement.

7. APPROVAL OF PROCESS WAIVER

While it is NPCC's intent to adhere to this manual under normal circumstances, NPCC may need to develop a new or modified regional standard, implementation plan, variance, clarification or definition under extenuating circumstances. Extenuating circumstances may include, but not be limited to, specific time constraint imposed by a regulatory body and urgent reliability issue that requires expedited handling outside of the normal regional Reliability Standards process.

The RSC, by two-thirds (2/3) majority vote, may waive any of the provisions contained in this manual for good cause shown, but limited to the following circumstances:

- Where necessary to meet regulatory deadlines
- Where necessary to address an urgent reliability issue identified by regulatory and/or governmental authorities, including response to 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 deadlines imposed by the NPCC Board of Directors

- Where the RSC determines that a revision to a proposed regional standard, implementation plan, variance, clarification or definition has already been vetted by the industry through the standards development process or is so insubstantial that developing the revision through the processes contained in this manual will add significant time delay without any corresponding benefit.

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 RSC by any entity or individual, including NPCC committees or subgroups and NPCC Standards Staff. Prior to consideration of any waiver request, the NPCC Manager of Reliability Standards must provide notification to stakeholders at least five (5) business days prior to RSC consideration and action. Posting the waiver request on the NPCC website satisfies the notification provision.

Action on the waiver request will be included in the minutes of the RSC. Following the approval of the RSC to waive any provision of the regional Reliability Standards process, the Assistant Vice President Standards shall report the exercise of this waiver provision to the NPCC Board of Directors prior to adoption of the related Reliability Standard, clarification, definition or variance. Actions taken pursuant to an approved waiver request will be posted on the NPCC Standards webpage.

8. PROCESS FOR CORRECTING ERRATA

Commented [HS17]: I think we need to discuss what constitutor's Errata.

errors in printing or writing, such as misspellings, omissions, and other typographical errors.

From time to time, an error in printing or writing, such as misspellings, omissions, and other typographical errors. may be discovered in a regional standard after it has received final ballot approval by the NPCC ballot body. Such errors may be corrected by the RSC without re-balloting if the RSC as a whole by ballot agrees that the correction of the error does not change the scope, applicability or intent of the associated regional standard, and agrees that the correction has no material impact on the compliance obligations of registered entities.~~end users of the regional standard~~.

If the regional standard containing errata is pending approval by the NPCC Board of Directors, the corrected regional standard shall be presented to the NPCC Board for approval in lieu of the regional standard approved by the NPCC ballot body.

If a regional standard containing errata had received prior approval by the NPCC Board of Directors, the corrected regional standard shall be presented to the NPCC Board for approval. Upon approval by the Board, the corrected regional standard will be filed for approval by NERC.

The NPCC Board of Directors has resolved to concurrently approve any errata approved by the RSC associated with a regional standard that has received prior approval by the NPCC Board.

9. APPEALS

Persons who have directly and materially affected interests and who have been or will be adversely affected by any substantive or procedural action or inaction related to the approval, revision, reaffirmation, or withdrawal of a regional standard (appellant) shall have the right to appeal. This appeals process applies only to the regional standards process as defined in this manual.

The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made within thirty (30) calendar days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. In all cases, the request for appeal must be made prior to the next step in the process.

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:

LEVEL 1 APPEAL

Level 1 is the required first step in the appeals process. The appellant submits a complaint in writing to the NPCC Manager of Reliability Standards that describes the substantive or procedural action or inaction associated with a Reliability Standard or the standards process. The appellant describes in the complaint the actual or potential adverse impact to the appellant. Assisted by any necessary NPCC Standards Staff and Committee resources, the NPCC Manager of Reliability Standards shall prepare a written response addressed to the appellant as soon as practical, but not more than forty-five (45) calendar days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response will be made a part of the public record associated with the standard and posted with the standard.

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 NPCC Manager of Reliability Standards, the NPCC Board of Directors shall appoint a five member panel to serve as a Level 2 Appeals Panel.

In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The NPCC Manager of Reliability Standards shall post the complaint and other relevant materials and provide at least a thirty (30) calendar day notice of the meeting of the Level 2 Appeals Panel.

In addition to the appellant, any person that is directly and materially affected by the substantive or 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 RSC with a statement of the issues and facts in regard to which unfair and/or inequitable action was taken, or which fair and/or equitable action was not taken. The panel may find for or 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. The actions of the Level 2 Appeals Panel shall be publicly posted.

In addition to the foregoing, a procedural objection that has not been resolved may be submitted to the NPCC Board of Directors for consideration at the time the Board decides whether to adopt a particular Reliability Standard. The objection must 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 must be filed no later than thirty (30) calendar days after the announcement of the vote on the standard in question.

APPENDIX A: RSAR COMPLETION GUIDELINES

Commented [JMW(18]: Suggestion to modify the RSAR form to mirror the NERC SAR

The Requester shall complete an RSAR form in accordance with the guidance provided below.

The RSAR, at a minimum, shall contain information in the required fields in order to be qualified for consideration. The NPCC Manager of Reliability Standards will assist the Requester to ensure all required information is submitted on the RSAR.

Information in a Regional Standard Authorization Request (RSAR)

The tables below identify information to be submitted in a Regional Standard Authorization Request to the NPCC Manager of Reliability Standards, at npccstandard@npcc.org. The NPCC Manager of Reliability Standards shall be responsible for implementing and maintaining this form as needed to support the information requirements of the standards process.

Regional Standard Authorization Request Form

Title of Proposed Standard:	***[Required Field]***
Request Date:	***[Required Field]***

RSAR Requester Information

Name:	***[Required Field]***	**RSAR Type (Check box for one of these selections.)**	
Company:	***[Required Field]***	☐	New Standard
Telephone:	***[Required Field]***	☐	Revision to Existing Standard
Fax:		☐	Withdrawal of Existing Standard
Email:	***[Required Field]***	☐	Urgent Action

Purpose: (Describe the purpose of the proposed standard – what the standard will achieve in support of reliability.)

[Required Field]

Industry Need: (Provide a detailed statement justifying the need for the proposed standard, along with a technical justification and any supporting documentation.)

[Required Field -- must include technical justification (relevant studies, documentation, etc.) for a new standard or revision to an existing standard.]

Brief Description: (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

[Required Field]

Reliability Functions *[Required Field]*

The Standard will Apply to the Following Functions (Check all applicable boxes.)		
☐	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
☐	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☐	Planning Coordinator~~A~~	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
☐	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
☐	Transmission Owner	The entity that owns and maintains transmission facilities.
☐	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
☐	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
☐	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
☐	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☐	Generator Owner	Entity that owns and maintains generating units.

☐	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
☐	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer.
☐	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check all boxes that apply.)*	
☐	1. Interconnected Bulk Electric System 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 Electric System 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 Electric System 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 Electric System 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 Electric System.
☐	6. Personnel responsible for planning and operating interconnected Bulk Electric System shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected Bulk Electric System shall be assessed, monitored, and maintained on a wide-area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*	
Recognizing that reliability is ~~an~~a Common Attribute of a robust North American economy:	
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes	

4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description: (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.) ***[Required Field – Provide: 1) Necessary information to assist the drafting team (which is to include relevant study results and documentation), to the extent feasible, to allow them to draft the standard, 2) Any existing known cross references to NPCC or NERC documents and 3) Technical background for the RSAR to properly address the need for the standard.]***

Related Standards *[Required Field, to extent known]*

Standard No.	Explanation

Related SARs or RSARs *[Required Field, to extent known]*

SAR ID	Explanation

APPENDIX B: SELECTION OF DRAFTING TEAM MEMBERS

A regional standard drafting team shall be comprised of Subject Matter Experts (SMEs) from NPCC Task Forces and Working Groups as determined by the RCC, and from industry. The guidelines provided herein primarily address overall team requirements and more specifically those of a SME.

Formal membership on a drafting team should be reserved only for those individuals who intend to work consistently, diligently, and professionally on what is required to be done for a regional standard. Drafting team members are expected to contribute meaningfully to the ongoing development of the standard.

Drafting Team members must be:

- Committed to participating in scheduled drafting team meetings, teleconferences, as well as industry outreach (e.g., workshops and webinars)
- Willing to lead teams / sub-teams, as necessary
- ~~Champions for standard development and promoters of the approval of the standard~~
- Open to consider the comments of others and provide constructive feedback

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Subject Matter Experts should possess the necessary expertise and knowledge regarding the topic of the standard. The SMEs should represent a cross section of the registered entities applicable to the standard under development as well as geographical areas within the NPCC footprint.

Industry stakeholders may nominate themselves for consideration by the NPCC Regional Standards Committee (RSC) for the specific drafting team vacancies by completing the following drafting team Self Nomination form and submitting it to NPCC Manager of Reliability Standards, at npccstandard@npcc.org.

Nomination Form for NPCC [Name of drafting team] Drafting Team

Please return this form as soon as possible. If you have any questions, please contact the NPCC Standards Staff at npccstandard@npcc.org.

By submitting the following information you are indicating your willingness and agreement to actively participate in the drafting team meetings if appointed to the drafting team by the NPCC Regional Standards Committee (RSC). This means that if you are appointed to the DT you are expected to attend all (or at least the vast majority) of the face-to-face DT meetings as well as participate in all the DT meetings held via conference calls. Failure to do so shall result in your removal from the DT.

Name:	
Organization:	
Address:	
Telephone:	

E-mail:	

Please briefly describe your experience and qualifications to serve on the requested drafting team.

If you are currently a member of any NERC or Regional drafting teams, please list each team here.

☐ Not currently on any active SAR or standard drafting team.

☐ Currently a member of the following SAR or standard drafting team(s):

If you previously worked on any drafting team please identify the team(s).

☐ No prior NERC or Regional SAR or standard drafting team experience.

☐ Prior experience on the following team(s):

Select each Industry Segment that you represent:

☐ ~~ERCO~~ ☐ ~~T~~ ☐ ~~FRCC~~ ☐ ~~MRO~~ ☐ ~~NPCC~~ ☐ ~~RFC~~ ☐ ~~SERC~~ ☐ ~~SPP~~ ☐ ~~WEC~~ ~~C~~ ~~NA – Not Applicable~~	☐	1 — Transmission Owners
	☐	2 — RTOs, ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities
	☐	NA – Not Applicable

Select each Function[~~2019~~1920] in which you have current or prior expertise:

☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

[~~2019~~1920] These functions are defined in the NERC Functional Model, which is downloadable from the NERC website.

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Commented [HS21]: We may want to add distributed Energy Resources as one of the check boxes

Commented [JMW(22R21]: I think we may want to stay with what is in the NERC functional model.

Commented [HS19]: This part of the form seems wrong. They should be from entities with interests in the NPCC region but have knowledge of the ERO framework as a whole.

What if we decide we need a storage standard for example.

Commented [JMW(20R19]: I suggest deleting the NERC Regions section.

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	

APPENDIX C: MAINTENANCE OF REGIONAL STANDARDS AND PROCESS

NPCC regional standards and the Regional Standard Processes Manual are living documents that will be updated periodically to remain current and viable (e.g., respond to changing conditions, as well as to incorporate lessons learned and process improvements).

MAINTENANCE OF REGIONAL STANDARDS

NPCC regional standards will be posted for open process review by the RSC for possible revision at least once every five (5) years[2~~01~~] after the first regulatory approval and follow the same process as in the case of a new standard. If no changes are warranted, the Regional Standards Committee (RSC) shall recommend to the NPCC Board that the standard be reaffirmed. If the review indicates a need to revise or retire a regional standard, a Regional Standard Authorization Request shall be prepared by the RSC and submitted in accordance with the NPCC regional standards process. The existing, approved standard subject to revision will remain in effect until such time as the revised version has received FERC or applicable Provincial Governmental Authorities approvals, as appropriate, at which time it will be retired in accordance with any applicable implementation plan associated with the newly approved regional standard.

MAINTENANCE OF THE REGIONAL STANDARDS PROCESS

This NPCC Regional Standards Process will be reviewed for possible revision at least once every five (5) years, or more frequently if needed, and subject to the same procedure as applies to the development of a Regional Standard. All such revisions shall be subject to approval by the NPCC Board of Directors, NERC Board of Trustees, FERC, and may be subject to approval, if required, by Applicable Governmental Authorities in Canada.

[2~~01~~] More frequent reviews of NPCC regional standards may be required to promptly evaluate new or revised NERC reliability standards to ensure NPCC regional standards remain consistent and more stringent than continent-wide reliability standards.

~~A~~APPENDIX D: NPCC CLARIFICATION REQUEST



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

Note: A valid clarification request is one that requests additional clarity about one or more requirements in approved NPCC regional standards, but does not request approval as to how to comply with one or more requirements.

When completed, email this form to: npccstandard@npcc.org
For questions about this form or for assistance in completing the form, call ~~Lee Pedowicz~~Guy Zito at 212-840-1070.

Request for an Clarification of a Regional Standard	
Date submitted:	
Contact information for person requesting the clarification:	
Name:	
Organization:	
Telephone:	E-mail:
Identify the standard that needs clarification:	
Standard Number (include version number, e.g. PRC-006-NPCC-1):	
Standard Title:	
Identify specifically what requirement needs clarification:	
Requirement Number and Text of Requirement:	
Identify the nature of clarification that is requested: (Check as many as applicable)	
☐ Clarify the required performance ☐ Clarify the conditions under which the performance is required ☐ Clarify which functional entity is responsible for performing an action in a requirement ☐ Clarify the reliability outcome the requirement is intended to produce Please explain the clarification needed:	
Identify the material impact associated with this clarification:	

Identify the material impact to your organization or others, if known, caused by the lack of clarity or an incorrect clarification of this standard.

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Northeast Power Coordinating Council, Inc. Regional Standards Committee

TPL-001-5, Transmission Planning Reliability Standard FERC Notice of Proposed Rulemaking (NOPR)

Guy V. Zito

NPCC AVP - Standards

FERC – TPL-001-5 Notice of Proposed Rulemakings (NOPR):

- **NOPR released June 20, 2019, Comments due back to FERC August 26, 2019**
- **NERC developed, adopted and filed version 5 of the TPL-001 in December of 2018**
- **TPL-001-5 addressed FERC Directives in two FERC Orders:**
  - FERC Order 754 -System Single Points of Failure Based on the Section 1600 Data Request, specifically Category P5 event Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System.
  - FERC Order 786- Outages of significant facilities less than six months could be overlooked for planning purposes (P3 and P6 events from Table), and stability analysis for spare equipment strategy

FERC – TPL-001-5 Notice of Proposed Rulemakings (NOPR):

- **Revisions in TPL-001-5 include;**
  - Revisions to both the Table 1 planning event (Category P5) and extreme events (Stability 2.a-h)
  - Footnote 13 to provide for more comprehensive study of the potential impacts of protection system single points of failure, and provides a description of what non-redundant components of a Protection System are considered to be.

FERC – TPL-001-5 Notice of Proposed Rulemakings (NOPR):

- **FERC's Concern**
  - A protection system single point of failure for a SLG fault Category P5 faulted element such as a generator, transmission circuit or transformer along with a failure to operate of a non-redundant component of the protection system (i.e., a single point of failure) results in cascading, a corrective action plan is required. However and in contrast, revisions to Table 1 include the study of a protection system single point of failure in combination with a three-phase fault as an extreme event, which does not require a corrective action plan and may result in cascading.

FERC – TPL-001-5 Notice of Proposed Rulemakings (NOPR):

- **FERC's Proposed Directive:**
  - NERC to develop modifications to the Reliability Standard to require corrective action plans for protection system single points of failure in combination with three-phase faults if planning studies indicate potential cascading.
  - FERC proposes that NERC address the directive within one year of the final Order and seeks comment on its proposals

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



Questions or Comments ?

TPL-001-5, Transmission Planning Reliability Standard Notice of Proposed Rulemaking (NOPR)

- Version 5 addressed;
  - FERC Order 754 -System Single Points of Failure Based on the Section 1600 Data Request, specifically Category P5 event Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System.
  - FERC Order 786- 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 the 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. NERC Filed TPL-001-5 with FERC on December 2018
- Revisions in TPL-001-5 include;
  - Revisions to both the Table 1 planning event (Category P5) and extreme events (Stability 2.a-h) and the associated footnote 13 to provide for more comprehensive study of the potential impacts of protection system single points of failure.
- FERC's Issue;
  A protection system single point of failure for a single-line-to-ground fault Category P5 event-which is a single-line-to-ground faulted element such as a generator, transmission circuit or transformer along with a failure to operate of a non-redundant component of the protection system (i.e., a single point of failure) results in cascading, a corrective action plan is required.
  However and in contrast, revisions to Table 1 include the study of a protection system single point of failure in combination with a three-phase fault as an extreme event, which does not require a corrective action plan. NERC's petition stated that the three-phase fault scenario is much rarer (compared to the single-line-to-ground fault) but also that this scenario could result in more significant impacts to an entity's system. Therefore, if an entity determines that its system will experience cascading as a result of a three-phase fault scenario, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event will be conducted but a corrective action plan is not required.

- NERC Data;
  NERC's petition stated that only 28 out of 12,000 protection system misoperations involved a three phase fault (Data from NERC MIDAS- years 2011 through 2018) and judged that this situation is rare. FERC counters that this is one event every eight months for the time period of data and cites statements in NERC's petition that this scenario has a more severe impact.
- NORP Proposes to approve TPL-001-5
- Comments due to FERC August 26, 2019
- Proposed Directive- NERC to develop modifications to the Reliability Standard to require corrective action plans for protection system single points of failure in combination with three-phase faults if planning studies indicate potential cascading.
- NPCC's Directory 1 planning criteria requirements for a Protection System Single Point of Failure in Combination with a Three Phase Fault if Planning Studies for potential cascading are very similarly worded to the proposed standard and only require an evaluation of potential actions and no corrective actions.
- NPCC led an effort and wrote a report on cost effectiveness for this project. The report appears to have been removed from the NERC website however no analysis was done for cost effectiveness on what was not proposed for the standard. Therefore, no information regarding cost effectiveness or cost benefit appears to be readily available for the three phase fault with a single point of failure or breaker failure.
- Do we have evidence of any situations within NPCC where the scenario would result in possible cascading? If so would this result in development of a CAP and expenditures as proposed under the FERC Directive to NERC?

167 FERC ¶ 61,249
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM19-10-000]

Transmission Planning Reliability Standard TPL-001-5

(June 20, 2019)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to approve Reliability Standard TPL-001-5 (Transmission System Planning Performance Requirements). The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, submitted the proposed Reliability Standard for Commission approval to address: (1) reliability issues concerning the study of single points of failure of protection systems; and (2) Commission directives regarding planned maintenance outages and stability analysis for spare equipment strategy. In addition, the Commission proposes to direct NERC to modify the Reliability Standards to require corrective action plans for protection system single points of failure in combination with a three-phase fault if planning studies indicate potential cascading.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER].**

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

Eugene Blick (Technical Information)
Office of Electric Reliability
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(301) 665-1759
eugene.blick@ferc.gov

Bob Stroh (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8473
robert.stroh@ferc.gov

SUPPLEMENTARY INFORMATION:

167 FERC ¶ 61,249
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning Reliability Standard TPL-001-5 Docket No. RM19-10-000

NOTICE OF PROPOSED RULEMAKING

(June 20, 2019)

1. Pursuant to section 215(d)(2) of the Federal Power Act (FPA), the Commission proposes to approve Reliability Standard TPL-001-5 (Transmission System Planning Performance Requirements).[1] The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted proposed Reliability Standard TPL-001-5 for Commission approval to address: reliability issues concerning the study of single points of failure of protection systems discussed in Order No. 754; and directives from Order No. 786 regarding planned maintenance outages and stability analysis for spare equipment strategy.[2]

2. Proposed Reliability Standard TPL-001-5 is one of two transmission planning Reliability Standards containing requirements for planning authorities and transmission planners to develop studies of their portions of the bulk electric system. Proposed Reliability Standard TPL-001-5 establishes transmission system planning performance

[1] 16 U.S.C. 824o(d)(2) (2012).

[2] *Interpretation of Transmission Planning Reliability Standard*, Order No. 754, 136 FERC ¶ 61,186, at P 19 (2011); *Transmission Planning Reliability Standards*, Order No. 786, 145 FERC ¶ 61,051, at PP 40, 89 (2013)

requirements within the planning horizon to promote a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. NERC states that the revisions in the proposed Reliability Standard are intended to enhance requirements for the study of protection system single points of failure.[3]

3. Proposed Reliability Standard TPL-001-5 requires each planning authority and transmission planner to perform an annual planning assessment of its portion of the bulk electric system considering a number of system conditions and contingencies. The proposed Reliability Standard employs a risk-based approach to the study of contingencies and the types of corrective action that are required if the entity's system cannot meet the specified performance requirements.[4] For scenarios considered to be more commonplace (i.e., planning events), the planning entity must develop a corrective action plan if it determines through studies that its system would experience performance issues. For the scenarios considered to be less commonplace, but which could result in potentially severe impacts such as cascading (i.e., extreme events), the planning entity

[3] A protection system "single point of failure" refers to a non-redundant component of a protection system that, if it failed, would affect normal clearing of faults. NERC Petition at 4.

[4] NERC defines "Corrective Action Plan" as, "A list of actions and an associated timetable for implementation to remedy a specific problem." Glossary of Terms Used in NERC Reliability Standards (May 13, 2019) (NERC Glossary).

(continued…)

must conduct a comprehensive analysis to understand both the potential impacts on its system and the types of actions that could reduce or mitigate those impacts.[5]

4. Proposed Reliability Standard TPL-001-5 contains revisions to both the planning event (Category P5) and extreme events (Stability 2.a-h) - identified in Table 1 (Steady State and Stability Performance Planning Events and Steady State and Stability Performance Extreme Events) and the associated footnote 13 - to provide for more comprehensive study of the potential impacts of protection system single points of failure.[6] Planning entities would be required to take action, consistent with currently-effective Reliability Standard TPL-001-4 requirements, to address system performance issues identified as a result of these studies. Additionally, the proposed Reliability Standard addresses the two Commission directives in Order No. 786. Accordingly, pursuant to section 215(d)(2) of the FPA, the Commission proposes to approve proposed Reliability Standard TPL-001-5 because it is responsive to the Commission's directives

[5] NERC defines "Cascading" as, "The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies." NERC Glossary.

[6] Proposed Reliability Standard TPL-001-5 includes an expanded list of protection system components for single points of failure studies. The selected list of components account for: (1) those failed non-redundant components of a protection system that may impact one or more protection systems; (2) the duration that faults remain energized until delayed fault clearing; and (3) the additional system equipment removed from service following fault clearing depending on the specific failed non-redundant component of a protection system. NERC Petition at 16.

(continued…)

and improves upon the currently-effective Reliability Standard by enhancing requirements for the study of protection system single points of failure.

5. Non-redundant protection systems can also misoperate when faced with a three-phase fault. Because three-phase faults are more serious than single-phase-to-ground faults, the consequences can be more severe, including cascading. However, rather than require a corrective action plan to address such events, proposed Reliability Standard TPL-001-5 only requires an evaluation of possible actions designed to reduce the likelihood or mitigate their consequences and adverse impacts.[7] NERC has not adequately justified categorizing protection system single points of failure in combination with a three-phase fault as an "extreme event" that only requires study, but not a corrective action plan, when there is the potential for cascading. We are not persuaded that such events do not necessitate corrective action plans because of their alleged rarity, particularly because their potential impacts may result in cascading. Thus, pursuant to section 215(d)(5) of the FPA, we also propose to direct that NERC develop modifications to the Reliability Standards to require corrective action plans for protection system single points of failure in combination with three-phase faults if planning studies indicate potential cascading.[8]

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[7] NERC, Informational Filing, Docket No. RM10-06-000, at 10 (filed March 15, 2012) (2012 Informational Filing). A three-phase fault can originate as a single-line-to-ground (SLG) fault as "it is not uncommon for a SLG fault to evolve to a multi-phase fault." *Id.*

[8] 16 U.S.C. 824o(d)(5).

I. Background

A. Section 215 and Mandatory Reliability Standards

6. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[9] Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[10] and subsequently certified NERC.[11]

B. Order No. 754

7. In Order No. 754, which approved an interpretation of Reliability Standard TPL-002-0, Requirement R1.3.10, the Commission determined that "there may be a system protection issue that merits further exploration by technical experts" and that there is "an issue concerning the study of the non-operation of non-redundant primary protection systems; e.g., the study of a single point of failure on protection systems."[12]

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

[10] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006).

[11] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[12] Order No. 754, 136 FERC ¶ 61,186 at P 19.

(continued…)

To address this concern, the Commission directed "Commission staff to meet with NERC and its appropriate subject matter experts to explore the reliability concern, including where it can best be addressed, and identify any additional actions necessary to address the matter."[13] The Commission also directed NERC "to make an informational filing . . . 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."[14]

8. In October 2011, Commission staff hosted a technical conference on single points of failure, which resulted in four consensus points and the following problem statement: "The group perceives a reliability concern regarding the comprehensive assessment of potential protection system failures by registered entities. The group agrees on the need to study if a [reliability] gap exists regarding the study and resolution of a single point of failure on protection systems."[15] One outcome of the 2011 technical conference, as described in the 2012 Informational Filing, was that NERC would issue a data request to aid in assessing whether single points of failure in protection systems pose a reliability concern. To that end, the NERC Board of Trustees subsequently approved a request for

[13] *Id.* P 20.

[14] *Id*.

[15] NERC, Order No. 754 Single Point of Failure Technical Meeting Notes at 8 (October 24-25, 2011).

(continued…)

data under the NERC Rules of Procedure.[16] Over the next two years, NERC collected data from transmission planners. Using the collected data, two subcommittees of the NERC Planning Committee, the System Protection and Control Subcommittee (SPCS) and the System Analysis and Modeling Subcommittee (SAMS), conducted an assessment of protection system single points of failure. The study examined in detail the protection systems related to nearly 4,000 buses. The findings were presented in a September 2015 report that concluded that single points of failure on protection systems posed a reliability risk that warranted further action.[17] The SPCS/SAMS Report recommended, after considering a variety of alternatives, that NERC modify Reliability Standard TPL-001-4 to best align with the Order No. 754 directives and maximize reliability of protection system performance. In particular, the SPCS/SAMS Report recommended that three-phase faults involving protection system failures be assessed as an extreme event in Reliability Standard TPL-001-4, as follows:

> Additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure. This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in TPL-001-4 Part 4.5. From TPL-001-4, 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 and adverse impacts of the event(s) shall be conducted.[18]

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[16] 2012 NERC Informational Filing at 7 (stating that the data request "is based on an approach that utilizes . . . a three-phase (3Ø) fault and assesses simulated system performance against performance measures").

[17] NERC, Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request at 11 (September 2015) (SPCS/SAMS Report).

[18] *Id.*

C. Order No. 786

9. In Order No. 786, the Commission approved the currently-effective version of the transmission system planning standard, Reliability Standard TPL-001-4. In that Order, the Commission also issued several directives to NERC, including two relating to future standard modifications that are addressed in proposed Reliability Standard TPL-001-5. First, the Commission expressed concern that the six-month outage duration threshold in Reliability Standard TPL-001-4, Requirement R1 could exclude planned maintenance outages of significant facilities from future planning assessments.[19] The Commission determined 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, and that 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. The Commission further determined that 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 nonconsequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding. The Commission directed NERC to modify the Reliability Standards to address this concern.

[19] Order No. 786, 145 FERC ¶ 61,051 at PP 40-45.

10. Second, while stating that NERC had met the Commission's Order No. 693 directive to include a spare equipment strategy for steady state analysis in Reliability Standard TPL-001-4, the Commission determined that a spare equipment strategy for stability analysis was not addressed in the standard. The Commission stated 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. Rather than direct a change at that time, however, the Commission directed NERC to consider the issue during the next review cycle of Reliability Standard TPL-001-4.[20]

D. NERC Petition and Proposed Reliability Standard TPL-001-5

11. On December 7, 2018, NERC submitted proposed Reliability Standard TPL-001-5 for Commission approval.[21] NERC maintains that the proposed Reliability Standard addresses potential system contingencies including the protection system single point of failure issue and Order No. 786 directives. With regard to protection system single points of failure, NERC indicates that Table 1 of the proposed Reliability Standard describes system performance requirements for a range of potential system contingencies required to be evaluated by the planner. Table 1 includes three parts: (1) Steady State & Stability

[20] *Id.* PP 88-89.

[21] Proposed Reliability Standard TPL-001-5 is not attached to this notice of proposed rulemaking (NOPR). The proposed Reliability Standard is available on the Commission's eLibrary document retrieval system in Docket No. RM19-10-000 and on the NERC website, www.nerc.com.

Performance Planning Events, (2) Steady State & Stability Performance Extreme Events, and (3) Steady State & Stability Performance Footnotes. Table 1 describes system performance requirements for a range of potential system contingencies required to be evaluated by the planner. The table categorizes the events as either "planning events" or "extreme events." The table lists seven contingency planning events (P1 through P7) that require steady-state and stability analysis as well as five extreme event contingencies: three for steady-state and two for stability. NERC asserts that proposed Reliability Standard TPL-001-5 also includes certain modifications to better ensure that planning entities are performing a more complete analysis of potential protection system single points of failure on their systems and taking appropriate action to address these concerns. NERC explains that the proposed Reliability Standard contains revisions to both the Table 1 planning event (Category P5) and extreme events (Stability 2.a-h) and the associated footnote 13 to provide for more comprehensive study of the potential impacts of protection system single points of failure.

12. NERC states that if the study of a protection system single point of failure for a single-line-to-ground fault (i.e., Category P5 event) results in cascading, a corrective action plan is required.[22] NERC considers this a relatively commonplace scenario, and it

[22] Proposed TPL-001-5 Reliability Standard, Table 1 (Steady State and Stability Performance Planning Events), Category P5 requires the study of a single-line-to-ground faulted element (e.g., generator, transmission circuit or transformer) along with a failure to operate of a non-redundant component of the protection system (i.e., a single point of failure) protecting the faulted element.

explains that an entity would be required to develop a corrective action plan if it determines that its system would be unable to meet the performance requirements of Table 1 for the Category P5 event.

13. In contrast, NERC proposes revisions to Table 1 to include the study of a protection system single point of failure in combination with a three-phase fault as an extreme event, which does not require a corrective action plan. NERC avers in its petition that the three-phase fault scenario is much rarer (compared to the single-line-to-ground fault). According to NERC, like the other extreme events in the proposed Reliability Standard, this scenario, while rare, could result in more significant impacts to an entity's system.[23] Under this approach, NERC asserts that, if an entity determines that its system will experience cascading as a result of a three-phase fault scenario, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event will be conducted but a corrective action plan is not required.

14. Based on a historical analysis of NERC data on protection system misoperations, NERC asserts that the expected likelihood of a three-phase fault event occurring and resulting in the most severe impacts would be small. NERC states that it reviewed over 12,000 protection system misoperations in its Misoperation Information Data Analysis

[23] *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218, at P 1826, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007) (describing extreme events as "events resulting in loss of two or more elements or Cascading" that do not require a corrective action plan rather than assigning a quantitative probability to the event).

(continued…)

System (MIDAS) database reported since 2011, of which only 28 involved three-phase faults. Of those, NERC states that 10 involved breakers that failed to operate, and the remaining 18 involved breakers that were slow to operate.[24] NERC explains that a failure to operate potentially indicates instances of a protection system single point of failure. While the potential for severe impacts from such events remains, NERC states that none of the 10 failure to trip scenarios reported since 2011 resulted in events that reached the threshold for reporting under Reliability Standard EOP-004 (Event Reporting).[25] With regard to the Order No. 786 directives, NERC states that proposed Reliability Standard TPL-001-5 provides for a more complete consideration of factors for selecting which known outages will be included in near-term transmission planning horizon studies.

[24] NERC Petition at 26, n.55 ("The ERO began to collect misoperations data in a common format beginning in 2011. Applicable entities are currently required to report information on Protection System misoperations to NERC pursuant to a request for data or information under Section 1600 of the NERC Rules of Procedure approved by the NERC Board of Trustees on August 14, 2014. Previously, the PRC-004 standard contained requirements for misoperation reporting."); *see also North American Electric Reliability Corp*., 151 FERC ¶ 61,129, at P 6 (2015) ("PRC-004-3, and the parallel Section 1600 Data Request provides means to accomplish this systematic analysis and correction").

[25] Reliability Standard EOP-004-3 (Event Reporting), Attachment 1: Reportable Events, contains a list of various thresholds for reporting certain events to NERC. Examples of reporting thresholds include: loss of firm load for 15 minutes or more if 300 MW or greater for entities with a previous year's demand of at least 3,000 MW, or 200 MW or greater for all other entities, and total generation loss within one minute 2,000 MW or greater for entities in the Eastern or Western Interconnection, or 1,000 MW for entities in the ERCOT or Quebec Interconnection.

II. Discussion

15. Pursuant to section 215(d)(2) of the FPA, the Commission proposes to approve proposed Reliability Standard TPL-001-5 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The proposed Reliability Standard will improve Bulk-Power System reliability by requiring enhanced transmission system planning with regard to the study of protection system single points of failure in combination with a single-line-to-ground fault, as discussed in Order No. 754. The Commission also proposes to approve the associated violation risk factors, violation severity levels and implementation plan.

16. With respect to the Order No. 786 directives, regarding planned maintenance outages and stability analysis for spare equipment strategy, the Commission proposes to determine that the revisions satisfy the directives. First, proposed Reliability Standard TPL-001-5 provides for a more complete consideration of factors for selecting which known outages will be included in near-term transmission planning horizon studies. In particular, the modifications reflected in proposed Reliability Standard TPL-001-5 address the Commission's concern that the exclusion of known outages of less than six months in currently-effective Reliability Standard TPL-001-4 could result in outages of significant facilities not being studied. Second, the proposed Reliability Standard modifies requirements for stability analysis to require an entity to assess the impact of the possible unavailability of long lead time equipment, consistent with the entity's spare equipment strategy.

17. In addition, the Commission, pursuant to section 215(d)(5) of the FPA, proposes to direct that NERC develop modifications to the Reliability Standards because certain protection system single points of failure may not be fully addressed even with the implementation of proposed Reliability Standard TPL-001-5. As discussed below, the Commission is concerned that the proposed Reliability Standard does not require responsible entities to develop corrective action plans to address protection system single points of failure in combination with a three-phase fault if planning studies indicate potential cascading. Accordingly, the Commission proposes to direct that NERC develop modifications to the Reliability Standards to require corrective action plans for protection system single points of failure in combination with three-phase faults if planning studies indicate potential cascading.

A. The Record Indicates There is a Reliability Gap for a Protection System Single Point of Failure in Combination with a Three-Phase Fault

18. While protection system single points of failure in combination with a three-phase fault must be studied under the proposed Reliability Standard to determine the impact of failure, the Commission believes that the record may not support NERC's contention that corrective action plans should not be required even when studies of the event indicate the potential for cascading. Specifically, NERC asserts that protection system single points of failure in combination with a three-phase fault is an extreme event that does not require a corrective action plan, even in cases where the study results indicate potential cascading. NERC claims that protection system single points of failure in combination with a three-phase fault are rare and, "[l]ike all of the 'extreme events' scenarios in this

[TPL-001 Standard risk-based] framework, the impacts of a protection system single point of failure in combination with a three phase fault could be severe in some cases, but are very unlikely."[26] Based on the present record, it is unclear whether such contingencies are as rare as NERC maintains.

19. A 2009 NERC Industry Advisory reported three system disturbances that occurred during a five-year period that were initiated by a protection system single point of failure in combination with a single-line-to-ground fault.[27] According to the Industry Advisory and supporting documentation, all three events evolved into either a multi-phase fault or a three-phase fault with cascading.[28] Moreover, in the 2012 Informational Filing, NERC reported that it is not uncommon for a single-line-to-ground fault to evolve into a multi-phase fault, and NERC stated that studies solely on single-line-to-ground faults may understate the reliability risk of single points of failure of protection systems.[29] As mentioned below, the NERC standard drafting team pointed to the likelihood of a single-line-to-ground fault evolving into a multi-phase fault when responding to stakeholder comments that a single-line-to-ground fault was a rare event.

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[26] NERC Petition at 26.

[27] NERC, Industry Advisory: Protection System Single Point of Failure (March 30, 2009) (2009 NERC Industry Advisory).

[28] *Id.* at 2 ("Three system disturbances were caused by failure of a single component (lockout or auxiliary relay) of a protection system.").

[29] 2012 NERC Informational Filing at 3, 10 ("identif[ying] five events between 2004 and 2010 in which a single point of failure on a protection system caused, in whole or in part, an event on the Bulk-Power System…").

(continued…)

20. NERC indicates that it reviewed over 12,000 protection system misoperations and determined that only 28 involved three-phase faults from 2011 through 2018. However that averages to approximately one three-phase fault event every three months. NERC, moreover, indicates that ten of those 28 misoperations involved breakers that failed to operate that could reasonably be assumed to be representative of protection system single points of failure, which averages to about one event every 8 months.[30] Although we recognize that three-phase faults constitute a relatively small subset of all protection system operations, under the following measure of one protection system single point of failure every 8 months, the occurrence of three-phase faults with misoperations could reasonably be viewed as regular occurrences. Thus, based on the information currently before us, we are not persuaded by NERC's analysis that three-phase faults are rare events that should be categorized with other extreme events in proposed Reliability Standard TPL-001-5 and should be studied but not have corrective action plans.

21. The record of development for proposed Reliability Standard TPL-001-5 also supports our concerns with the absence of a corrective action plan requirement. The development record evidences a standard drafting team repeatedly expressing concerns regarding the reliability risks of three-phase faults involving protection system single points of failure. Indeed, the standard drafting team evaluated and initially adopted more

[30] NERC Petition at 26-27. NERC stated that none of the ten failure to trip scenarios reached the threshold for reporting under Reliability Standard EOP-004. Although NERC did not offer further explanation, system conditions such as off-peak load conditions could have contributed to whether Reliability Standard EOP-004 thresholds were met.

robust options to mitigate protection system single points of failure in combination with three-phase faults if studies indicated cascading, including requiring a corrective action plan or some variation of a corrective action plan.

22. In the first draft of proposed Reliability Standard TPL-001-5, the standard drafting team included a draft requirement (Requirement R4.6) that would have addressed protection system single points of failure in combination with a three-phase fault, including a specific requirement for the development of a corrective action plan.[31] After reviewing the unofficial comments on the proposal, the standard drafting team provided the following response:

> The [standard drafting team (SDT)] recognized that the industry comments . . . were particularly negative. The SDT would like to address the most common comment received: requiring Corrective Action Plans as part of Requirement R4.6 goes beyond the scope of the SAR, was not part of the recommendations from the SPCS/SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request", and/or is not justifiable given the low likelihood of occurrence. . . . While it is clear that a [single point of failure (SPF)] for a Protection System component may lead to significantly longer Delayed Clearing and notably worse system response than typically analyzed breaker failure conditions, the industry has indicated that the probability of simultaneous SPF occurrence with a bolted three-phase fault is low. Therefore the SDT has restored the assessment of SPF for a Protection System component with a three-phase fault to language consistent with TPL-001-4 Requirement 4.5.[32]

[31] NERC Petition, Ex. G (Summary of Development and Complete Record of Development) at page 372-373 of pdf ("If the analysis concludes there is Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h, a Corrective Action Plan shall be developed.").

[32] *Id.* at page 810 of pdf.

While the standard drafting team agreed to remove the corrective action plan provision in response to the stakeholder comments, the following language from the standard drafting team's response stressed the reliability concerns posed by protection system single points of failure in combination with a three-phase fault, and suggested that the related risks are "underappreciated":

> The SPF for a Protection System component is an important topic that, the SDT believes, may involve risks that are underappreciated. The SDT considered using Corrective Action Plan changes in proposed Requirement 4.6 or a new Table 1 Planning Events Category P8 to emphasize the importance of this issue, but given the industry comments and lack of a FERC directive did not "raise the bar" at this time. The SDT would like to document an important considerations (sic) it considered, that the fault conditions and system performance requirement, referred to as Performance Measure, of the Order 754 data request were very similar to those of Extreme Events of TPL-001-4 Table 1, namely three-phase fault application and conditions that can indicate Cascading. The primary conclusive finding of the SPCS/SAMS report was: "analysis of the data demonstrates the existence of a reliability risk associated with single points of failure in protection systems that warrants further action." Further, the SPCS/SAMS report concluded that: "additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure."[33]

The standard drafting team's above response acknowledged the importance of a corrective action plan and noted conclusive findings of the SPCS/SAMS report that the reliability risk associated with protection system single points of failure warrants further action. The standard drafting team, nonetheless, indicated that "lacking a FERC directive" it would remove the corrective action plan provision.

[33] *Id.*

23. The standard drafting team then developed a second draft of proposed Reliability Standard TPL-001-5. The second draft did not require a corrective action plan by name. Rather, the standard drafting team developed and submitted for ballot a new provision requiring that, when system studies show that a protection system single points of failure in combination with a three-phase fault results in system cascading, the entity must take specific actions, namely "listing system deficiencies, the associated actions needed to prevent the system from Cascading and the associated timetable for implementation."[34] Further, the proposed provision would require follow-up in annual planning assessments for "continued validity and implementation status."

24. The standard drafting team developed a technical rationale document that accompanied the second draft of the proposed Reliability Standard.[35] In the draft technical rationale document, the standard drafting team explained the technical basis for draft Requirement R4.2.2:

> Given the risk to BES reliability, additional emphasis in planning studies should be placed on assessment of three-phase faults involving Protection System SPF. This concern (the study of Protection System SPF) is appropriately addressed as an extreme event in TPL-001-4, Requirement R4, Part 4.2. While less probable than single-phase-to-ground faults, *three-phase faults typically initiate as single-phase-to-ground and often evolve into three-phase faults*, leading to Delayed Fault Clearing scenarios more severe than the Table 1 P5 event. Therefore, TPL-001-4, Requirement R4, Part 4.5, which specifies that an evaluation of possible mitigating actions

[34] *Id*. at page 824 of pdf (proposed Requirement 4.2.2).

[35] *Id.* at page 942 of pdf.

(continued…)

> be conducted if analysis concludes there is cascading caused by the occurrence of this extreme event, *is inadequate to address the risk of Protection System component SPF to the reliability of the BES*.[36]

Again, the standard drafting team expressed its concerns regarding the reliability risks associated with a protection system single point of failure in combination with a three-phase fault. The standard drafting team addressed the stakeholder comments regarding the perceived low risk of such conditions by pointing out that "[w]hile less probable than single-phase-to-ground faults, three-phase faults typically initiate as single-phase-to-ground and often evolve into three-phase faults, leading to Delayed Fault Clearing scenarios more severe than the Table 1 P5 event."[37] Further, the standard drafting team noted the inadequacy of simply conducting an "evaluation" as set forth in the relevant provision of the current Reliability Standard.[38]

25. The standard drafting team developed a third draft of the proposed Reliability Standard. This third draft removed the more robust provision (proposed Requirement R4.2.2) in favor of the currently proposed language in Requirement 4.2, which requires that "[i]f 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

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[36] *Id.* at page 950-951 of pdf (emphasis added).

[37] *Id*.

[38] The second draft of Reliability Standard TPL-001-5, was voted down by stakeholders, with stakeholders suggesting the removal of Requirement R4.2.2 again suggesting that three-phase fault followed by a protection failure is a low probability event. *Id*. at page 1327 of pdf.

consequences of the event (s) shall be conducted." Significantly, however, in the draft technical rationale document associated with the second draft of the proposed Reliability Standard, the standard drafting team stated that merely requiring that "an evaluation of possible mitigating actions be conducted if analysis concludes there is cascading caused by the occurrence of this extreme event, *is inadequate to address the risk of Protection System component SPF to the reliability of the BES*."[39]

26. The standard development history discussed above therefore supports our concern that there is a potential reliability gap with respect to the proposed Reliability Standard's treatment of protection system single points of failure in combination with a three-phase fault.[40]

B. Commission Proposal

27. The Commission, pursuant to section 215(d)(5) of the FPA, proposes to direct that NERC develop modifications to require corrective action plans for protection system single points of failure in combination with three-phase faults if planning studies indicate potential cascading. While we do not propose to prescribe how NERC should respond to the proposed directive, we discuss below certain possible alternatives.

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[39] *Id.* at page 951 of pdf (emphasis added).

[40] The standard development record indicates several stakeholder comments in support of a corrective action plan requirement for protection system single points of failure in combination with a three-phase fault that was proposed in the third draft. For example, one commenter suggested "the best way to achieve this [corrective action plan] requirement is through the creation of a P8 [new category planning event] contingency rather than extreme events." Another commenter stated it "does not believe though that the language . . . goes far enough . . . and believes a corrective action plan should be required." *Id.* at pages 2283, 2291, 2415, and 2424 of pdf.

28. NERC could address the proposed directive by modifying the current Category P5 proposal for single-line-to-ground faults (that already includes a P5 corrective action plan) to include language, such as, a footnote stating that the simulation of Delayed Fault Clearing must consider that a single-line-to-ground faulted condition may evolve to all three-phases before protection system action operates to clear the fault. Alternatively, NERC could modify the Reliability Standard to have a new Category planning event that would require a corrective action plan for the study of a protection system single point of failure in combination with a three-phase fault if the study indicates cascading.[41]

29. In addition, we recognize that during the standard drafting process for proposed Reliability Standard TPL-001-5 some stakeholders were concerned with incurring significant costs to mitigate protection system single points of failure in combination with a three-phase fault, while others stated that such actions do not usually incur significant costs.[42] While we are aware of the potential for increased cost under this proposal, we understand that there are likely cost-effective actions that could be taken to mitigate a protection system single point of failure in combination with a three-phase fault. For example, a corrective action plan to eliminate a single point of failure of protection system could add a redundant lockout relay in the control circuitry of a protection system,

[41] *See id.* at page 1506 and 1746 of pdf.

[42] *See*, *e.g.*, *id.* at page 1016 (Seattle City Light), 1019 (Arizona Public Service), 1044 (Northeast Power Coordinating Council), 1048 (Eversource Energy), 1331 and 1333 (Standard Drafting Team Response to Commenters) of pdf.

(continued…)

which would eliminate occurrence of those events reported in the 2009 NERC Industry Advisory.[43] As another option, an entity could add control center monitoring and reporting functions to a DC battery bank or to a communication system of a communication-aided protection scheme so that system operators are aware of their failure.[44] To better understand the potential for increased costs and other implementation issues, the Commission seeks comment on how many corrective action plans are expected for protection system single points of failure in combination with a three-phase fault if study results indicate cascading.

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[43] NERC Petition at 20 ("most, if not all, constituent parts of the control circuitry are generally unmonitored, may fail, and may remain undetected until periodic testing is conducted. This is particularly significant for non-redundant auxiliary relays or lockout relays within the control circuitry because they may be used for multiple functions . . . ."). In addition, the standard drafting team stated that "[i]t is emphasized that Footnote 13 does not prescribe any level of redundancy . . . . If, after proper consideration and simulation, required System performance is achieved, then there may be no impetus to make non-redundant components of a Protection System redundant. On the other hand, after proper consideration and simulation it is demonstrated that required System performance is not achieved, making non-redundant components of a Protection System redundant may be but one of many alternatives for corrective actions to obtain required System performance." *Id.*, Ex. G at page 162 of pdf.

[44] NERC Petition at 18-19 (stating that "[f]ootnote 13 provides that certain non-redundant components that are both monitored and reported at a Control Center would not need to be considered as part of planning studies. This includes the communications systems identified in footnote 13.b. The standard drafting team considered that the monitoring and reporting of a non-redundant component to a centralized location (i.e., the Control Center) would facilitate prompt identification and correction of abnormal conditions to minimize the exposure to and consequence of the failed component . . . Similar to footnote 13.b, monitoring and reporting the status of the DC supply to a centralized location [i.e., footnote 13.c] can be considered 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").

(continued…)

30. To ensure no delay and to align the effective date of the proposed directive with the current implementation plan of proposed Reliability Standard TPL-001-5, the Commission proposes to direct that NERC address the directive within one year of the effective date of a final rule.[45] The Commission seeks comments on its proposals.

III. Information Collection Statement

31. The FERC-725N information collection requirements contained in this notice of proposed rulemaking are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[46] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[47] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

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[45] NERC Petition, Exhibit B (Implementation Plan) at 2.

[46] 44 U.S.C. 3507(d) (2012).

[47] 5 CFR 1320.11 (2018).

32. The Commission bases its paperwork burden estimates on the changes in paperwork burden presented by proposed Reliability Standard TPL-001-5. The NERC Compliance Registry, as of May 10, 2019, identifies approximately 144 planning coordinators and transmission planners in the United States that are subject to mandatory compliance with this proposed Regulatory Standard. Of the 144 entities 62 of the entities are registered as both transmission planners and planning coordinators. The register indicates there are seven entities registered as planning coordinators and 137 entities registered as transmission planners.

33. Burden Estimate[48]: The estimated burden and cost for the requirements contained in this proposed rule follows:

[48] "Burden" is the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the information collection burden, refer to 5 CFR § 1320.3.

RM19-10-000 NOPR FERC-725N (Mandatory Reliability Standards: Reliability Standard TPL-001-5)					
Areas of Modification	**Number of Respondents (1)**	**Annual Number of Responses [49] per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response [50] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**
Single Point of Failure (one-time)	206 (PC/TP)[51]	1	206	16 hrs. (reporting: 12 hrs.; recordkeeping: 4 hrs.); $880	3,296 hrs; $181,280
Spare Equipment Strategy (one-time)	206 (PC/TP)	1	206	4 hrs. (reporting: 2 hrs.; recordkeeping: 2 hrs.); $220	824 hrs; $45,320
Plan Maintenance Outage (one-time)	206 (PC/TP)	1	206	16 hrs. (reporting: 12 hrs.; recordkeeping: 4 hrs.) $880	3,296 hrs; $181,280
TOTAL			**618**		**7,416 hrs; $407,880**

[49] We consider the filing of an application to be a "response."

[50] Hourly costs are based on the Bureau of Labor Statistics (BLS) figures for May 2017 (Sector 22, Utilities) for wages (https://www.bls.gov/oes/current/naics2_22.htm) and benefits for December 2019 (https://www.bls.gov/news.release/ecec.nr0.htm). We estimate that an Office and Administrative Support (Occupation code: 43-0000) would perform the functions associated with recordkeeping requirements, at an average hourly cost (for wages and benefits) of $41.34. The functions associated with reporting requirements, we estimate, would be performed by an Electrical Engineer (Occupation code: 17-2051) at an average hourly cost of $68.10 including wages and benefits. These occupational categories' wage figures are averaged and weighted equally as follows: ($41.34 hour + 68.10 hour) ÷ 2 = $54.72/hour. The resulting wage figure is rounded to $55.00/hour for use in calculating wage figures in the NOPR in Docket No. RM19-10-000.

[51] Entity count based on May 10, 2019 NERC Registration: 7 entities register as Planning Coordinators (PC), 137 entities register as Transmission Planners (TP), and 62 entities register as both PCs and TPs.

This notice of proposed rulemaking will not significantly change existing burdens on an ongoing basis. The Commission estimates a one-time burden increase for Year 1 only because Year 1 represents a one-time task not repeated in subsequent years.

The one-time burden for FERC-725N information collection can be averaged over three years:

- 7,416 hours ÷ 3 = 2,472 (rounded) hours/year over three years.

34. Title: FERC-725N, Mandatory Reliability Standards: Transmission Planning (TPL) Reliability Standards

Action: Proposed revision to FERC-725N information collection.

OMB Control No.: 1902-0264.

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: One Time

Necessity of the Information: This notice of proposed rulemaking proposes to approve the requested modifications to a Reliability Standard pertaining to transmission planning. As discussed above, the Commission proposes to approve proposed Reliability Standard TPL-001-5 pursuant to section 215(d)(2) of the FPA because it improves upon the currently-effective Reliability Standard TPL-001-4.

Internal Review: The Commission has reviewed proposed Reliability Standard TPL-001-5 and made a determination that its action is necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is

specific, objective support for the burden estimates associated with the information requirements.

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

36. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission, and to the Office of Management and Budget, Office of Information and Regulatory Affairs, 725 17th Street NW, Washington, DC 20503, [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-0710, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to: oira_submission@omb.eop.gov. Comments submitted to OMB should include Docket Number RM19-10-000 and FERC-725N (OMB Control No. 1902-0264).

IV. Environmental Analysis

37. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[52] The Commission has categorically excluded certain actions

[52] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

(continued…)

from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[53] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Analysis

38. The Regulatory Flexibility Act of 1980 (RFA)[54] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities.[55] The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[56] The SBA revised its size standard for electric utilities (effective January 22, 2014) to a standard based on the number of employees, including affiliates (from the prior standard based on megawatt hour sales).[57]

39. Proposed Reliability Standard TPL-001-5 is expected to impose an additional burden on 206 entities[58] (planning coordinators and transmission planners).

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[53] 18 CFR 380.4(a)(2)(ii) (2018).

[54] 5 U.S.C. 601-612 (2012).

[55] *Id.* 601-12.

[56] 13 CFR 121.101 (2018).

[57] *Id.* 121.201.

[58] Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this NOPR, we are using a 500 employee threshold due to each affected entity falling within the role of Electric Bulk Power Transmission and Control (NAISC Code: 221121).

40. Of the 206 affected entities discussed above, we estimate that approximately 10 percent of the affected entities are small entities. We estimate that each of the 21 small entities to whom the proposed modifications to proposed Reliability Standard TPL-001-5 apply will incur one-time costs of approximately $1,980 per entity to implement the proposed Reliability Standard. We do not consider the estimated costs for these 21 small entities to be a significant economic impact. Accordingly, we propose to certify that proposed Reliability Standard TPL-001-5 will not have a significant economic impact on a substantial number of small entities.

VI. Comment Procedures

41. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 60 days after publication in the FEDERAL REGISTER**]. Comments must refer to Docket No. RM19-10-000, and must include the commenter's name, the organization they represent, if applicable, and address.

42. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

43. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

44. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

45. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

46. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.User assistance is available for eLibrary and the Commission’s website during normal business hours from the Commission’s Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or e-mail at

ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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-014-3

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 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.

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-014-3.

6. Background:

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

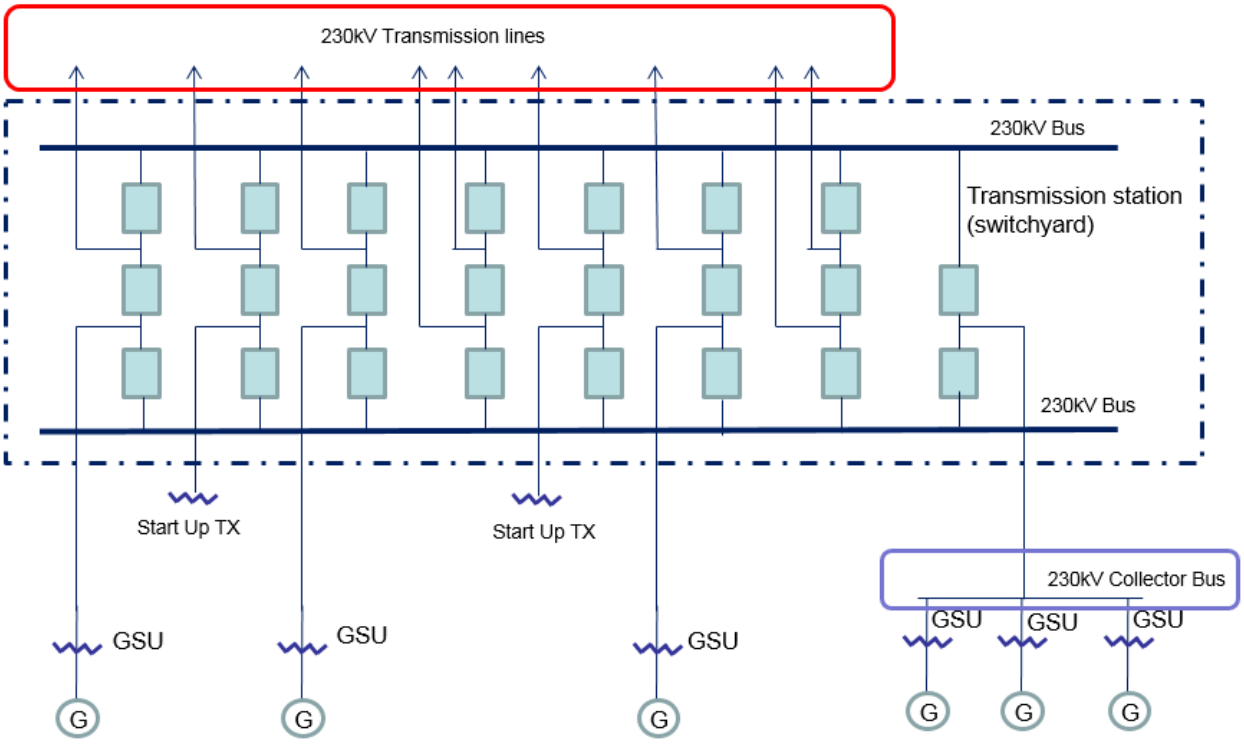
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within 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 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:

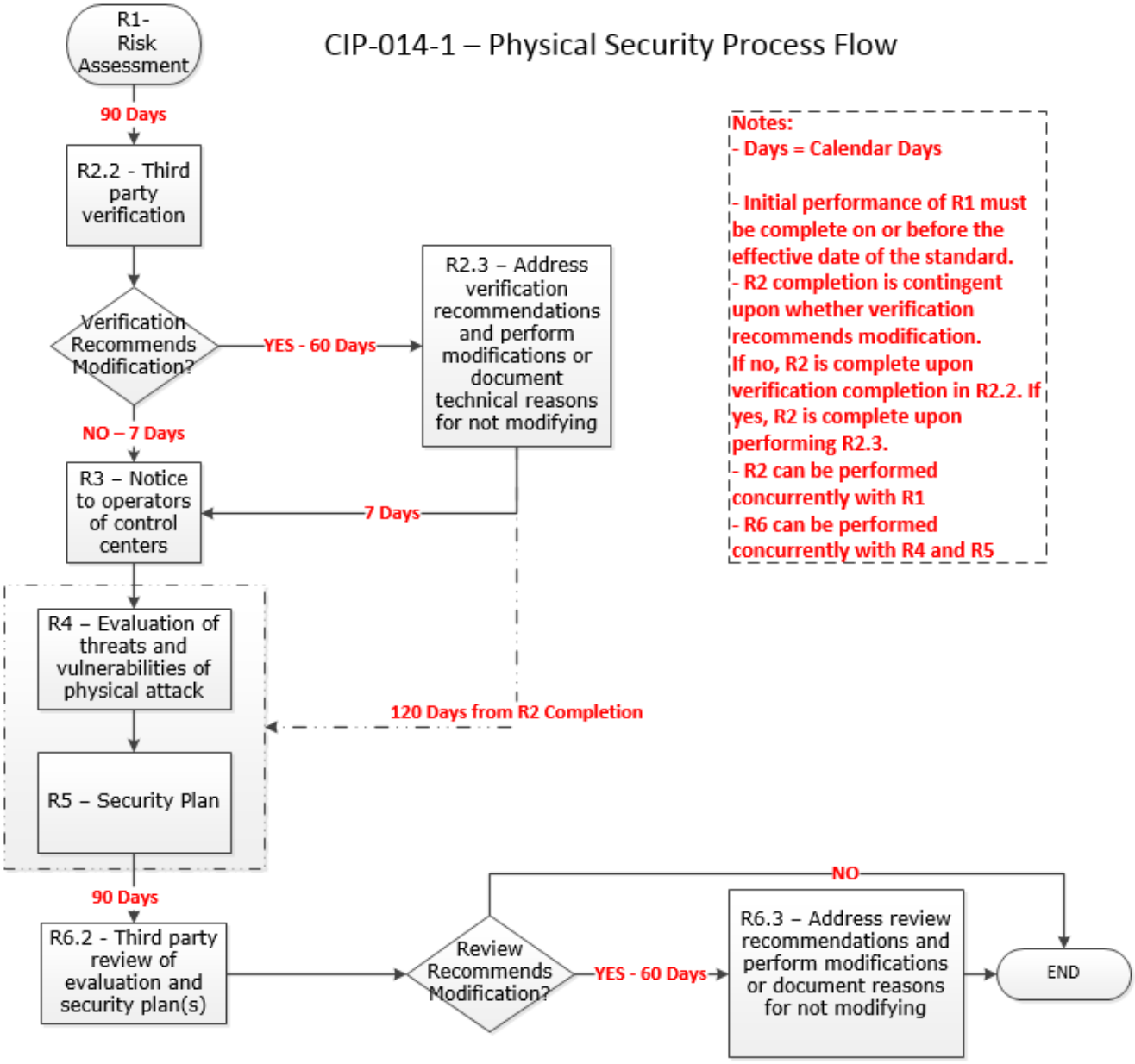
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

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

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

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

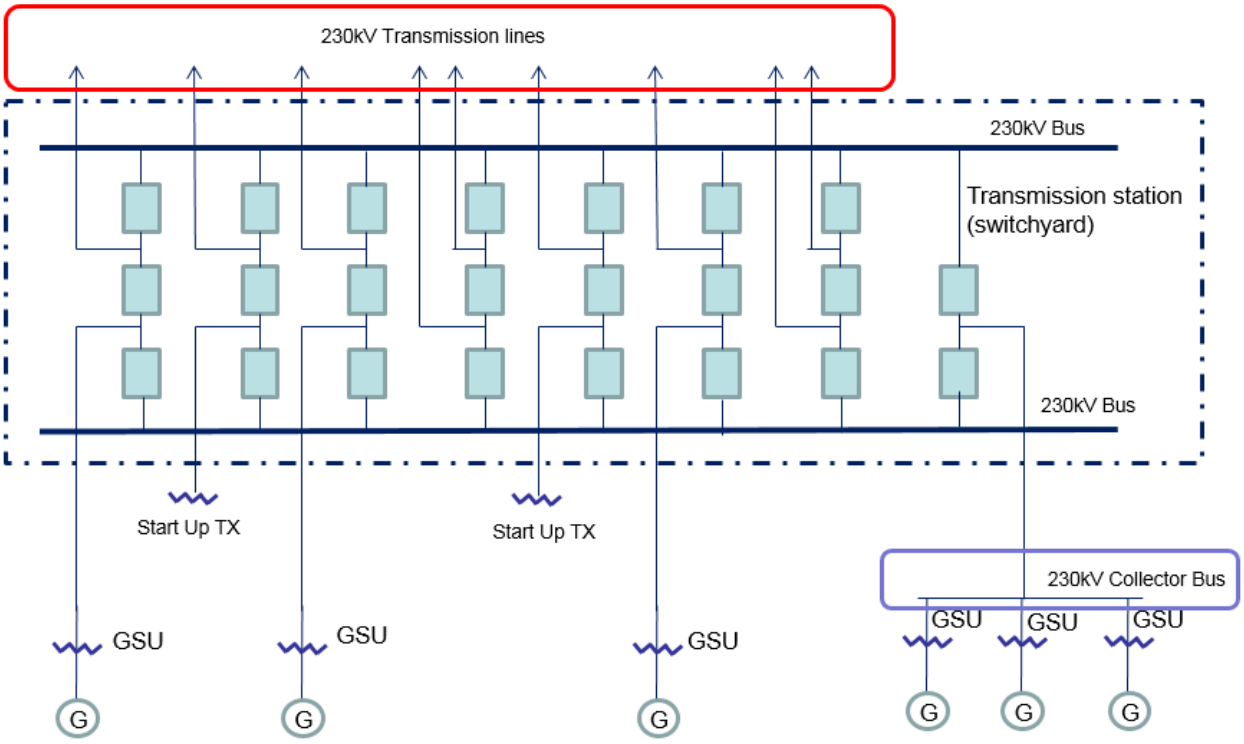
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within 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:

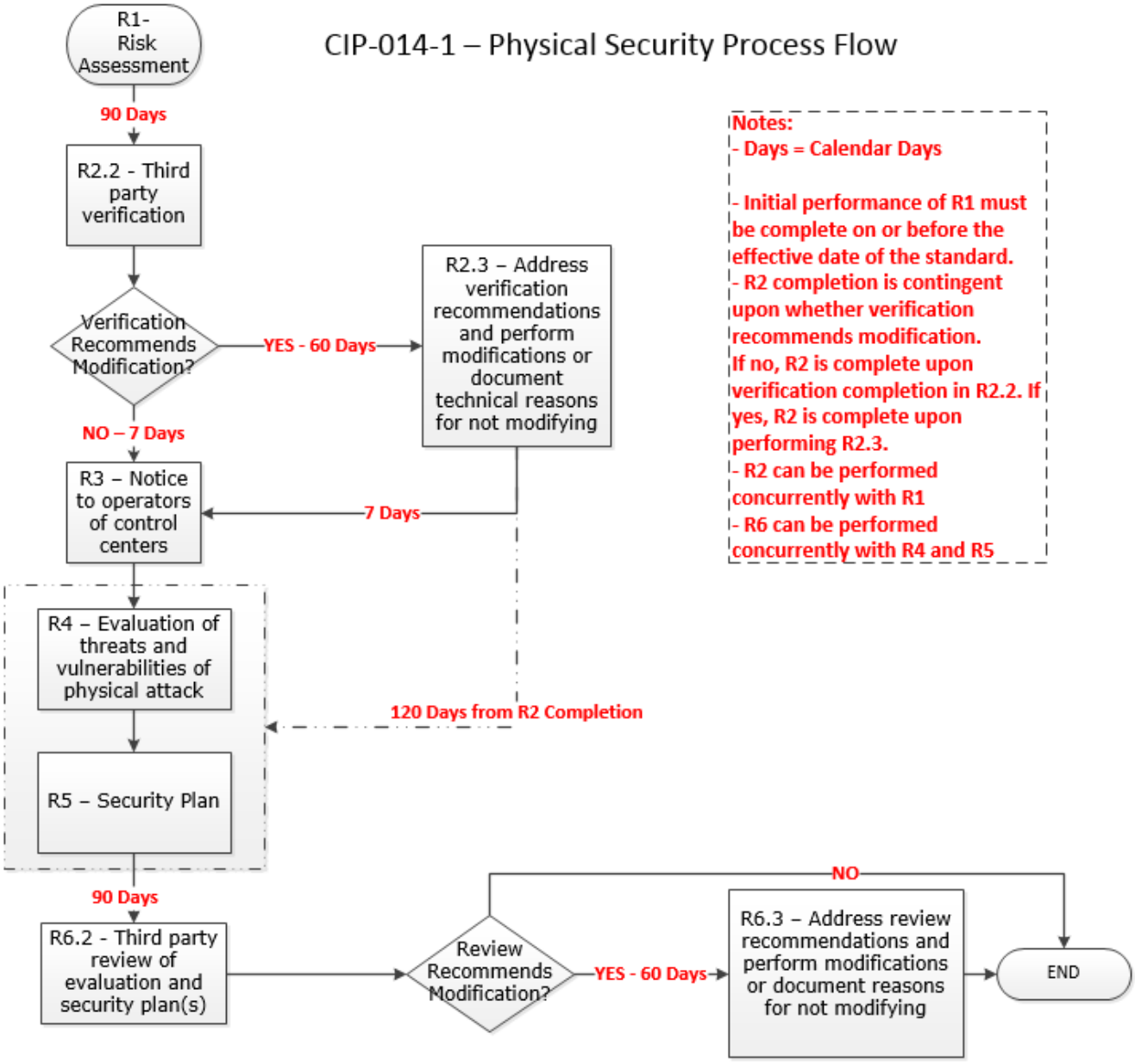
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

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

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-003-5

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.

   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.; 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 conditions (if any), shall have what capability, to achieve what particular result or*

[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.

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 Reliability Standards development recognizes that each requirement in a NERC Reliability Standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability Standards 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 Reliability Standard.

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), 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]

2.1.

M2. [Reserved for future use]

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;

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[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 Reliability Standard, 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.*

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 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[9] [*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.). 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[10]
- **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

[9] 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.

[10] 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.

(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.

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, 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, 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, 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, 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, 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, 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 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 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.				•
R3.		The responsible entity has maintenance strategies or documented procedures or 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.)	The responsible entity has maintenance strategies or documented procedures or 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.)	The responsible entity does not have any maintenance strategies or documented 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 line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - 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."[11]	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	Revisions

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

		requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	
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
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)[12]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[13]	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[14]	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)

[+] *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)*

[12] 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.

[13] 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.

[14] 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 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[15]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[16]	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 4268m up to 4572m
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[17]	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)

+ *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)*

[15] 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.

[16] 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.

[17] 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 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[18]

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)

[18] 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, 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 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 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 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 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.

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 is a greater risk to the interconnected electric transmission system than applicable lines that have not been identified as such. Applicable lines that 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.

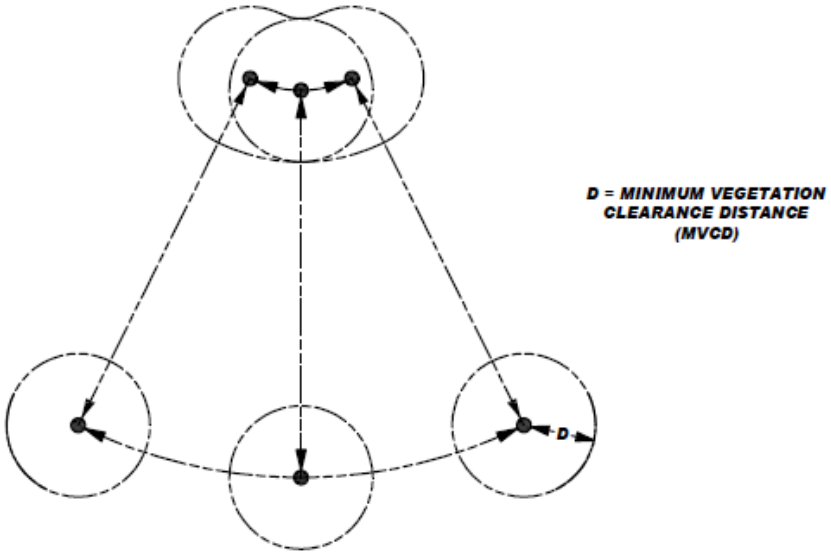


Figure 1

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:
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

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.

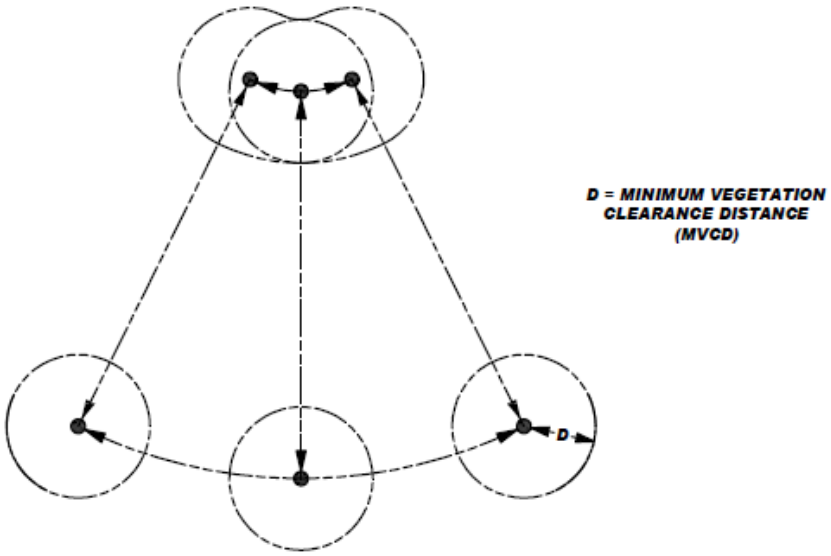


Figure 1

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 which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator 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/station have an associated System Voltage Limit, unless the Reliability Coordinators SOL Methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;

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

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

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Require the use of common System Voltage Limits between the Transmission Operator and its Reliability Coordinator 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. 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 stability limits are 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.

4.7. State that the use of underfrequency load shedding (UFLS) 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 identify in its SOL Methodology the 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 SOL Methodology shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Specify the following single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2. Identify any additional single or multiple Contingency events or types of Contingency events for use in performing Operational Planning Analysis and Real-time Assessments.

5.3. Identify any additional single or multiple Contingency events or types of Contingency events for use in determining stability limits.

5.4. 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 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.

R7. Each Reliability Coordinator shall include in its SOL Methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

7.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

7.2. Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL T_V.

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.

R8. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate their established SOLs to the Reliability Coordinator. The method shall address the periodicity for communicating established SOLs. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

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.

R9. Each Reliability Coordinator shall provide its SOL Methodology to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

9.1. 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 Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

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.

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 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.
R7.	N/A	N/A	The Reliability Coordinator failed to include Part 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 7.1 and 7.2 in its SOL Methodology.

			OR The Reliability Coordinator failed to include Part 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 7.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	
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.
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 three 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 four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date

	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 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 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in 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 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 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	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: 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 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)	
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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
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

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1	November 1, 2006	Adopted by Board ~~of Trustees~~	New
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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-013-3

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.

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's Planning Assessments.

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 1.3 • 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 1.3 • 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 1.3 • 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

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			
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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			
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	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

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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
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Rationale

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Rationale for R2:
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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

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 additional ballot	August 2018 – October 2018
10-day final ballot	October 2018
NERC Board adoption	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 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 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 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 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 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, 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 shall use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to 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, that demonstrates the Transmission Operator and Reliability Coordinator used the Bulk Electric System performance criteria specified in 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 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 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 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 failed to provide its SOLs at the periodicity at which the RC needs such information	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

			to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator 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 failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.6.
R6.	N/A	N/A	N/A	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	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: 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

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
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3		Project 2015-09 Adopt revised standard.	Revision

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Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- 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
- CIP-014-2 Physical Security
- FAC-003-4 Transmission Vegetation Management
- FAC-013-2 Assessment of Transfer Capability for the Near-term Transmission 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, 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 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, 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 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 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, FAC-015-1, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, the NERC Glossary 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 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, 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, 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.

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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-002-3

3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.

4. **Applicability:**

   Functional Entities:

   4.1 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 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 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 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 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, 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, 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator 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 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 required BES Elements included in Part 5.1.	The 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 required BES Elements included in Part 5.1.	The Reliability Coordinator 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 required BES Elements included in Part 5.1.	The Reliability Coordinator 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

			OR The 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	OR The 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 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.	OR The 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 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.	The 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 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 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	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	
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 in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

			determined in Requirement R5.	own as determined in Requirement R5.	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	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	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.

				directed by Requirement R10.	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 by the requesting authority. OR The Transmission Owner or Generator	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 was granted by the requesting authority. OR The Transmission Owner or Generator	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 was granted by the requesting authority. OR The Transmission Owner or Generator	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. OR The Transmission Owner or Generator Owner as directed by Requirement R11

			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.	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.	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.	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 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal	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 100-calendar days but less than or	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 110-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after

			to 100-calendar days after discovery of the failure.	equal to 110-calendar days after discovery of the failure.	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.	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. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> 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

High Level Requirement Overview

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

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	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:

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator 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 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 Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The 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 Reliability Coordinator. Data for each BES Element as defined by the 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 Reliability Coordinators, each 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 Reliability Coordinator will determine which entity will provide the data. The 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 Reliability Coordinators. It is intended that each 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 Reliability Coordinator 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 Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator 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 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 Reliability Coordinator 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 Reliability Coordinator 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 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:** 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-023-5

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.

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.

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.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

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	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**

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 generator or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. Elements associated with angular instability identified in Planning Assessments.
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[1] 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] 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[2] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[3] 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.

[2] 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."

[3] 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.

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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.[4] 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.

[4] 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,[5] ("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."[6] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[7] 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"[8] 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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[5] 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)

[6] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[7] Ibid. P.153.

[8] 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:[9]

> 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.

[9] 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),[10] 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 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 any generating output limitation or RAS. A stability constraint limits the output of the portion of the

[10] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

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 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 or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission lines 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[11] power swing during a simulated 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

[11] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

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[12] and PRC-025[13] 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.

[12] Transmission Relay Loadability

[13] 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.[14]

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-

[14] *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.[15] 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

[15] 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.[16]

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.

[16] "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.

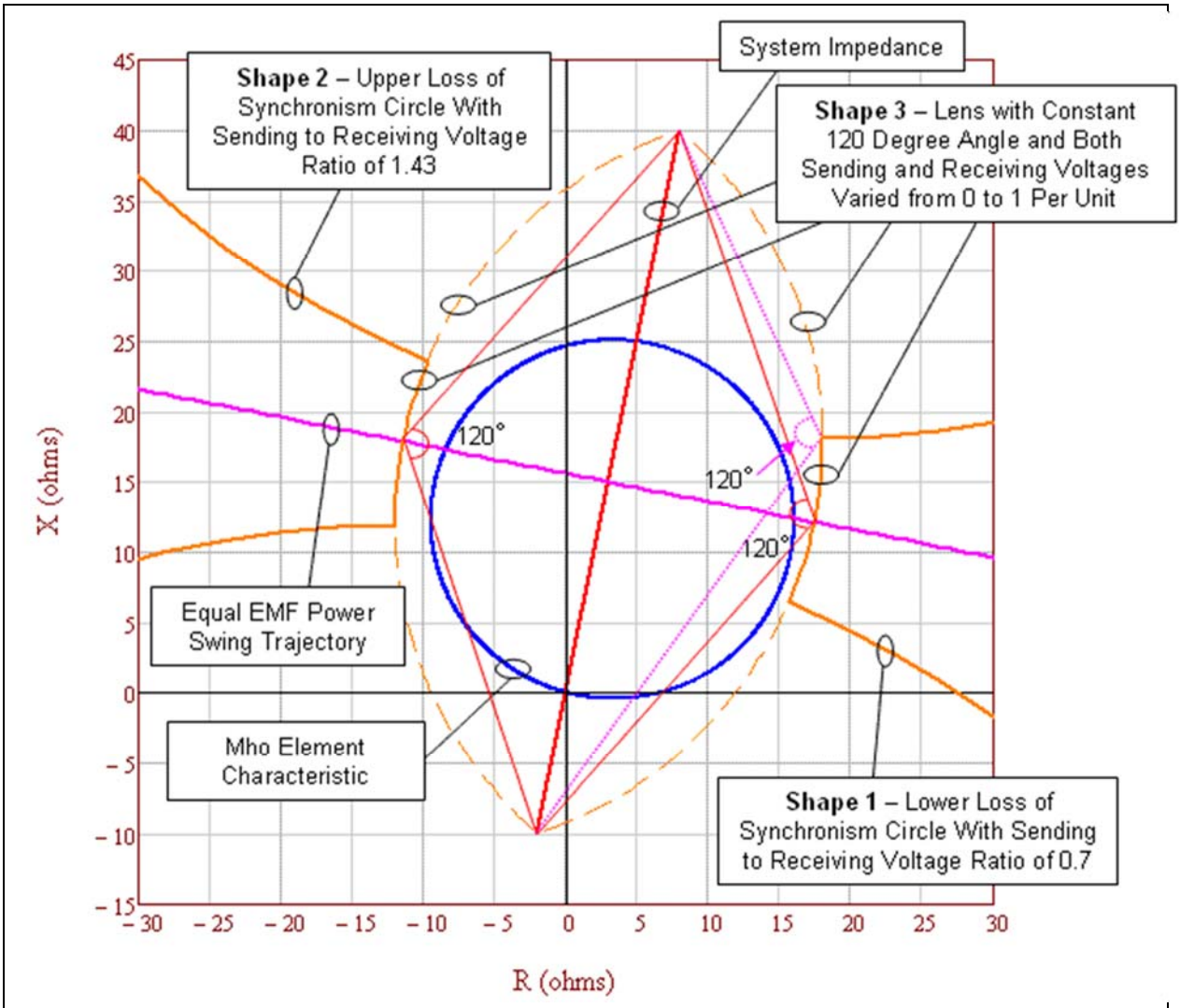


Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained 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.

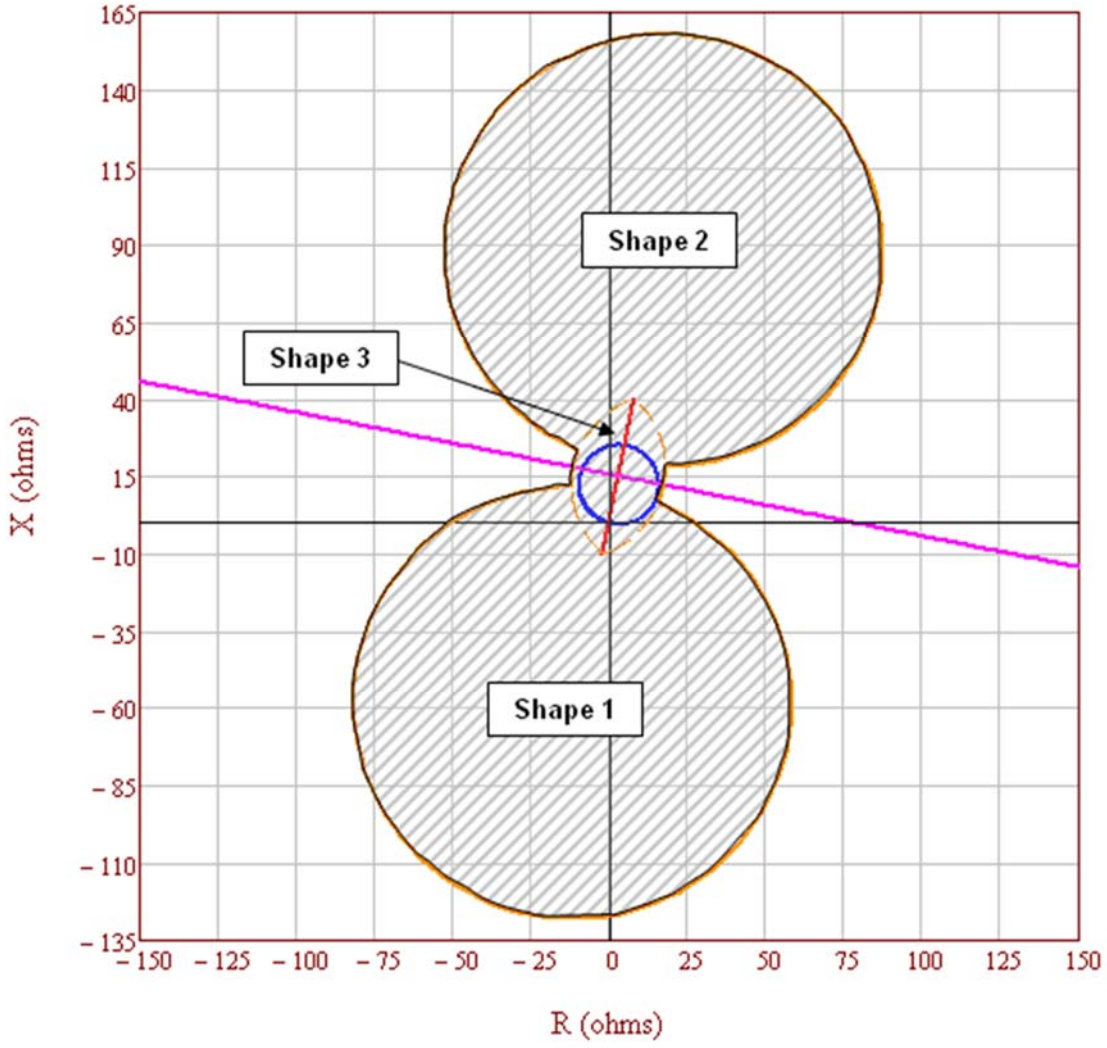


Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

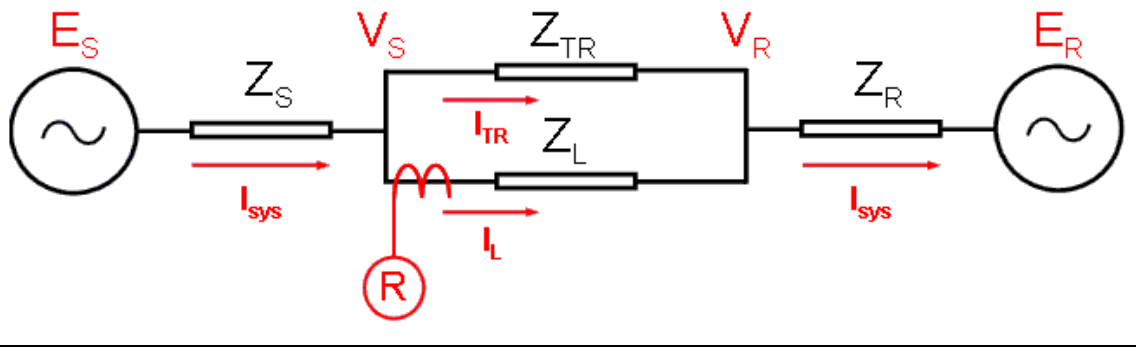


Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

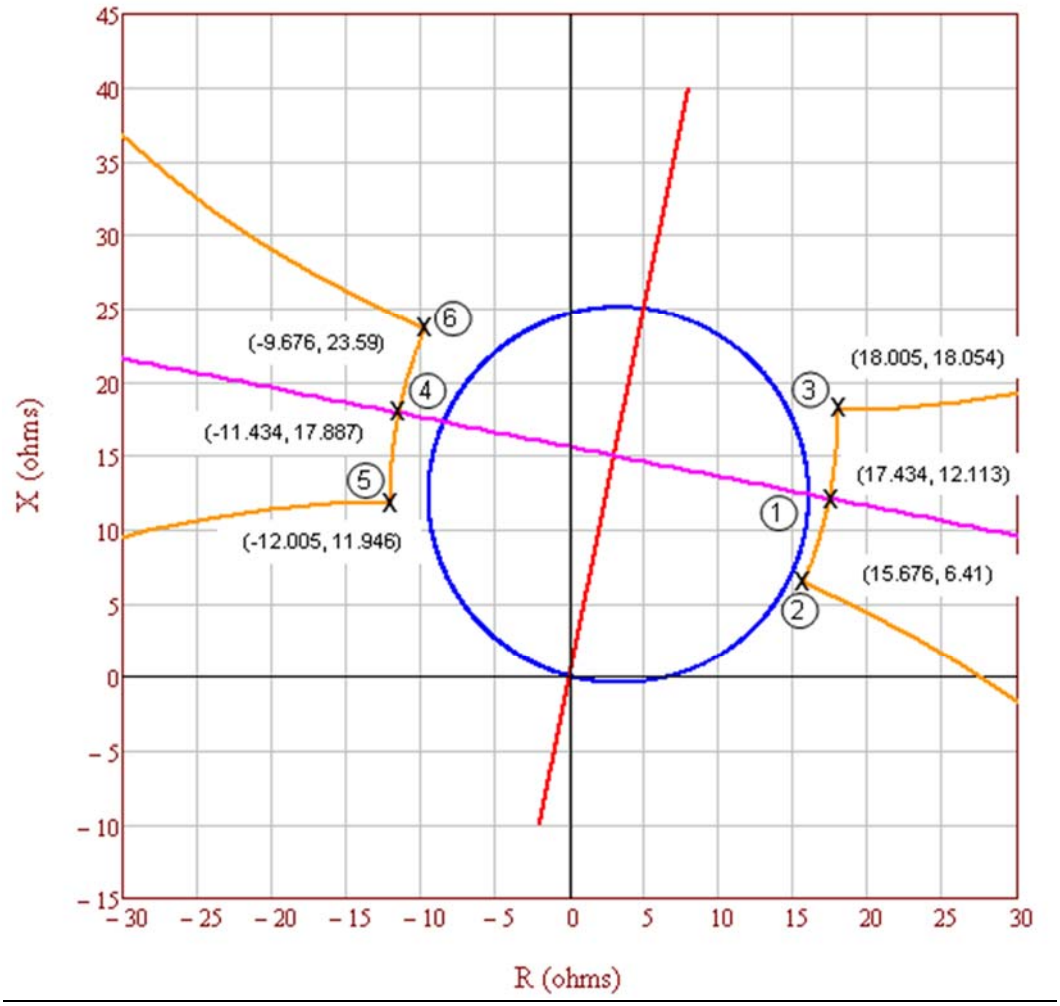


Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

E_S / E_R Voltage Ratio	Left Side Coordinates R	Left Side Coordinates + jX	Right Side Coordinates R	Right Side Coordinates + 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)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle -110.6° \, V}{3{,}854\angle 137.1° \, A}$
	$Z_{L-Relay} = -9.676 + j23.59 \, \Omega$

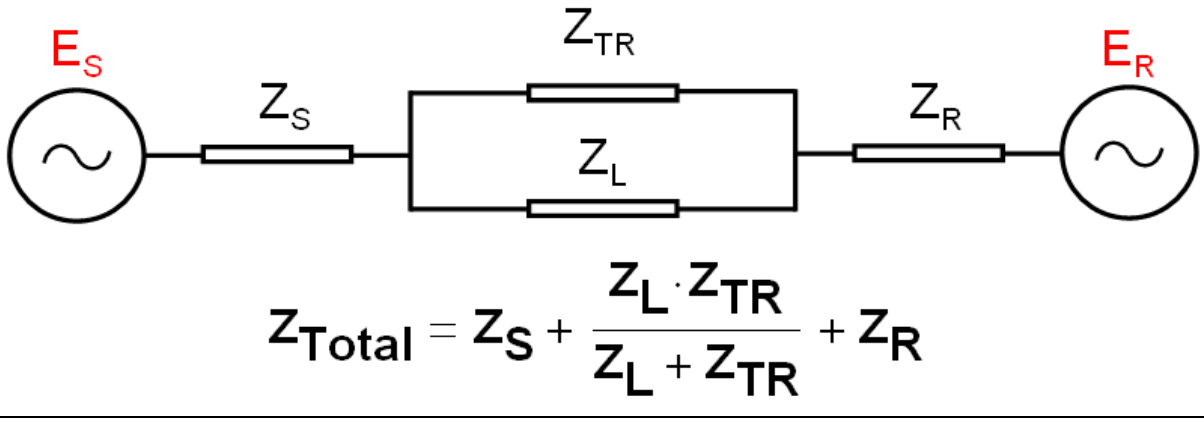


Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.

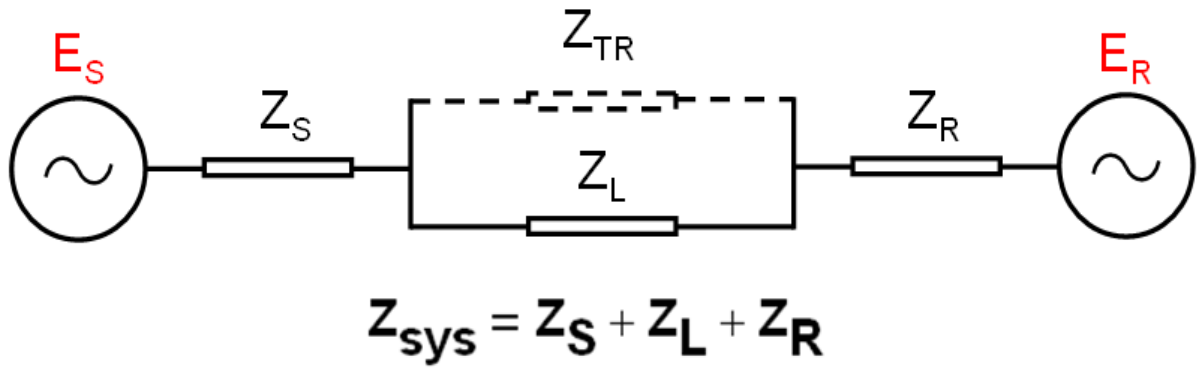


Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

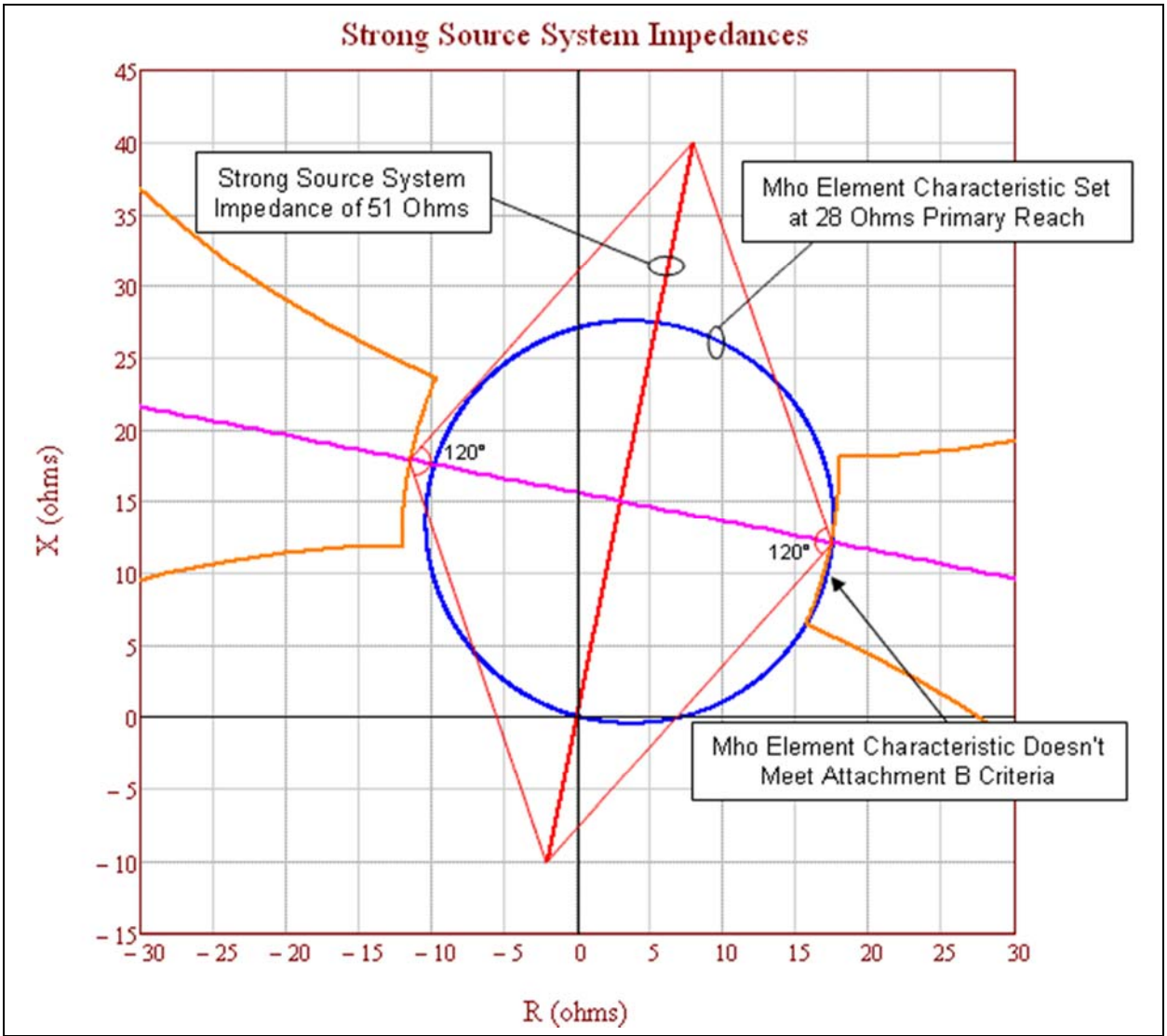


Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., 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.

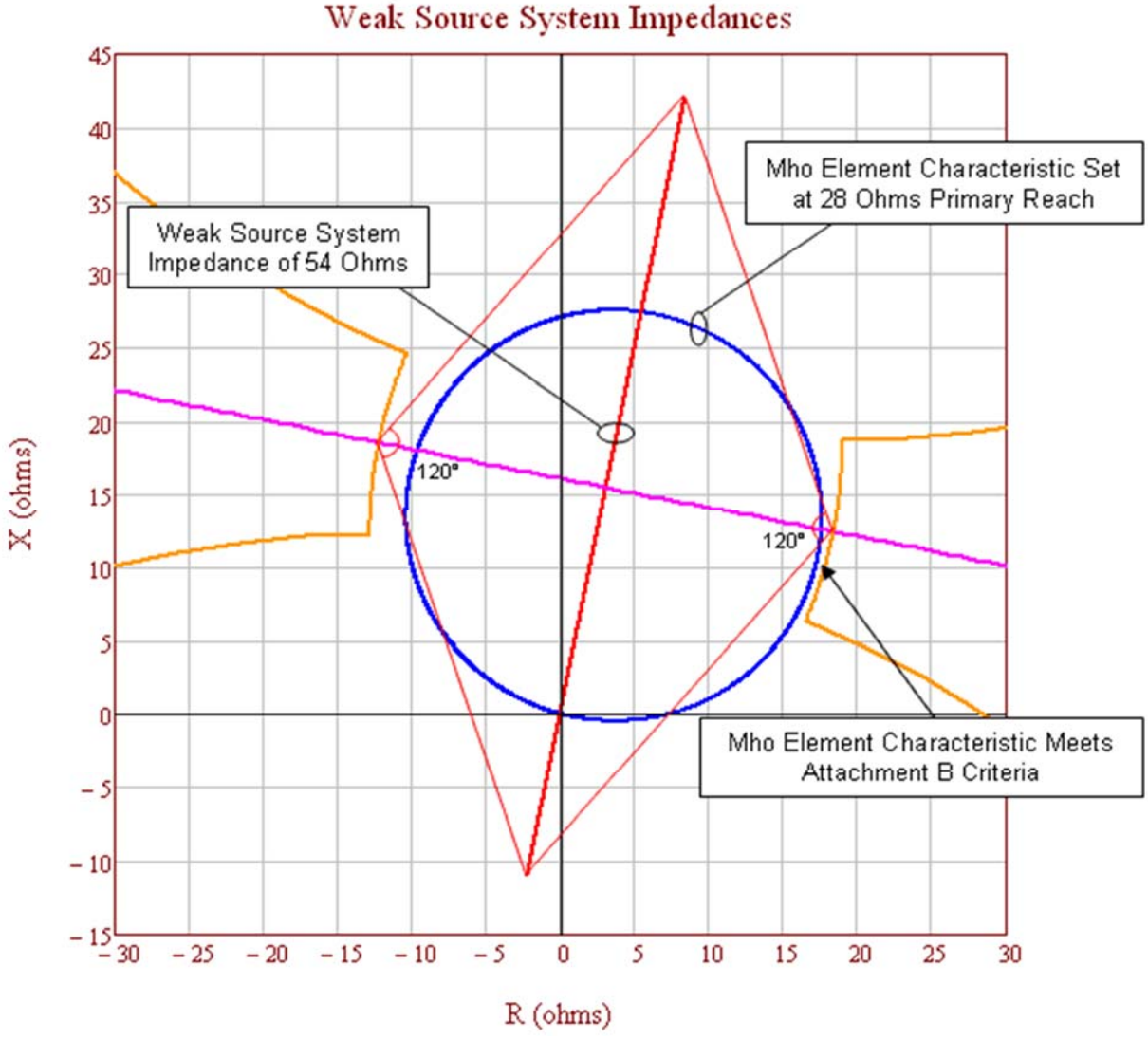


Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

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.

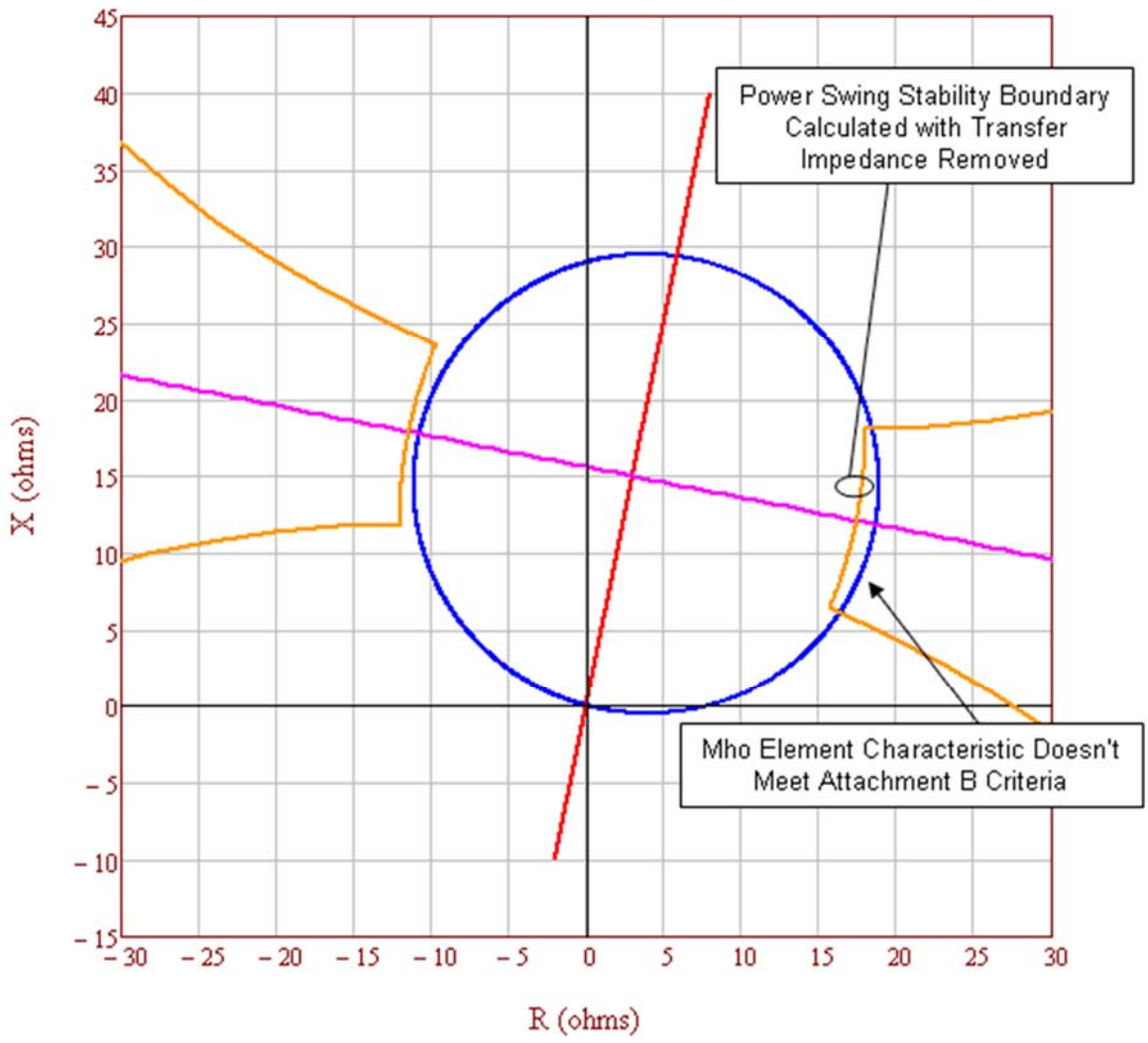


Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-1 – Attachment B, Criterion A because it is not completely contained within 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)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120° \, V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3° \, A]$
	$V_S = 95{,}757\angle 106.1° \, V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1° \, V}{4{,}511\angle 71.3° \, A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

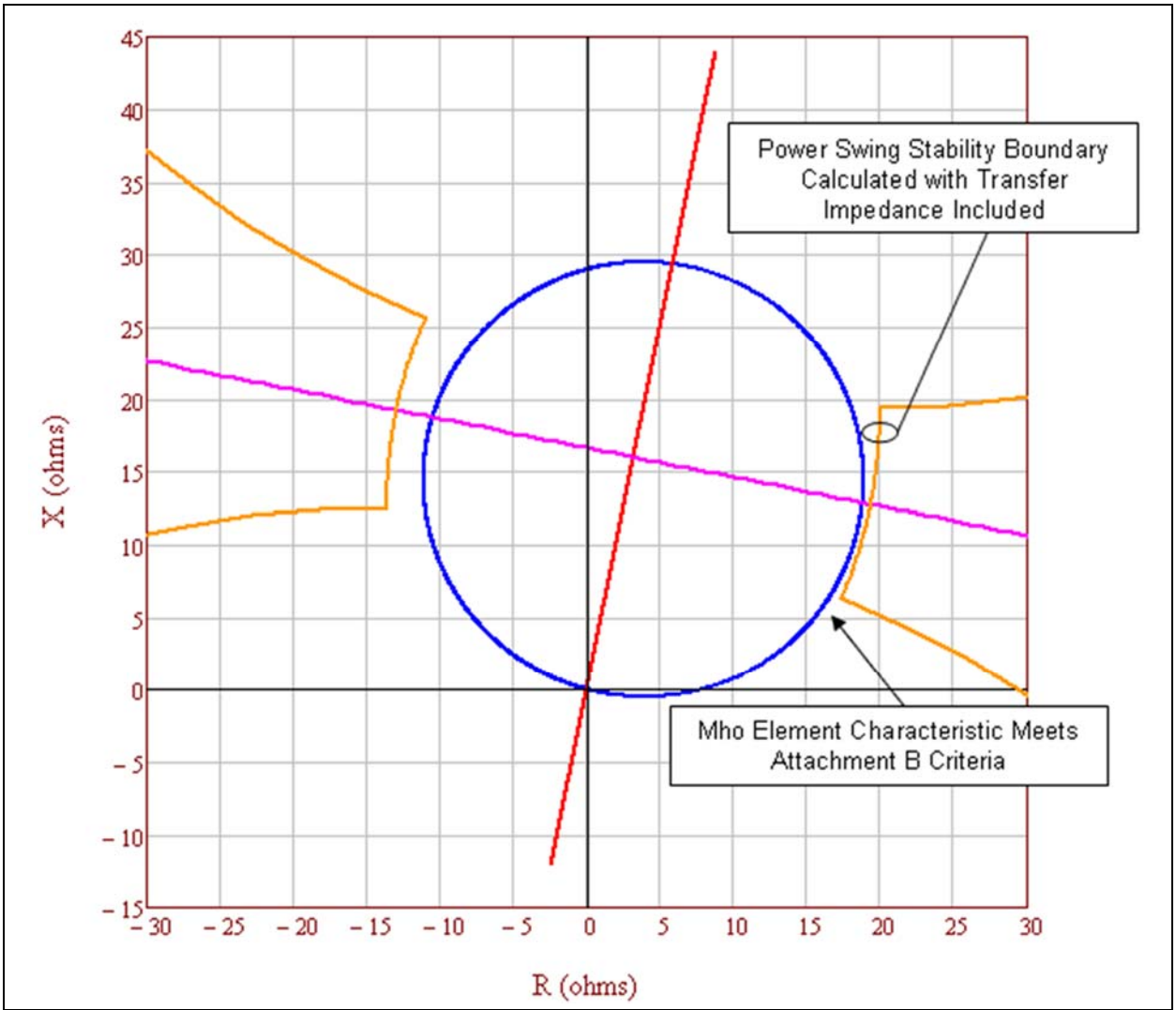


Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-1 – Attachment B, Criterion A because it is completely contained 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%

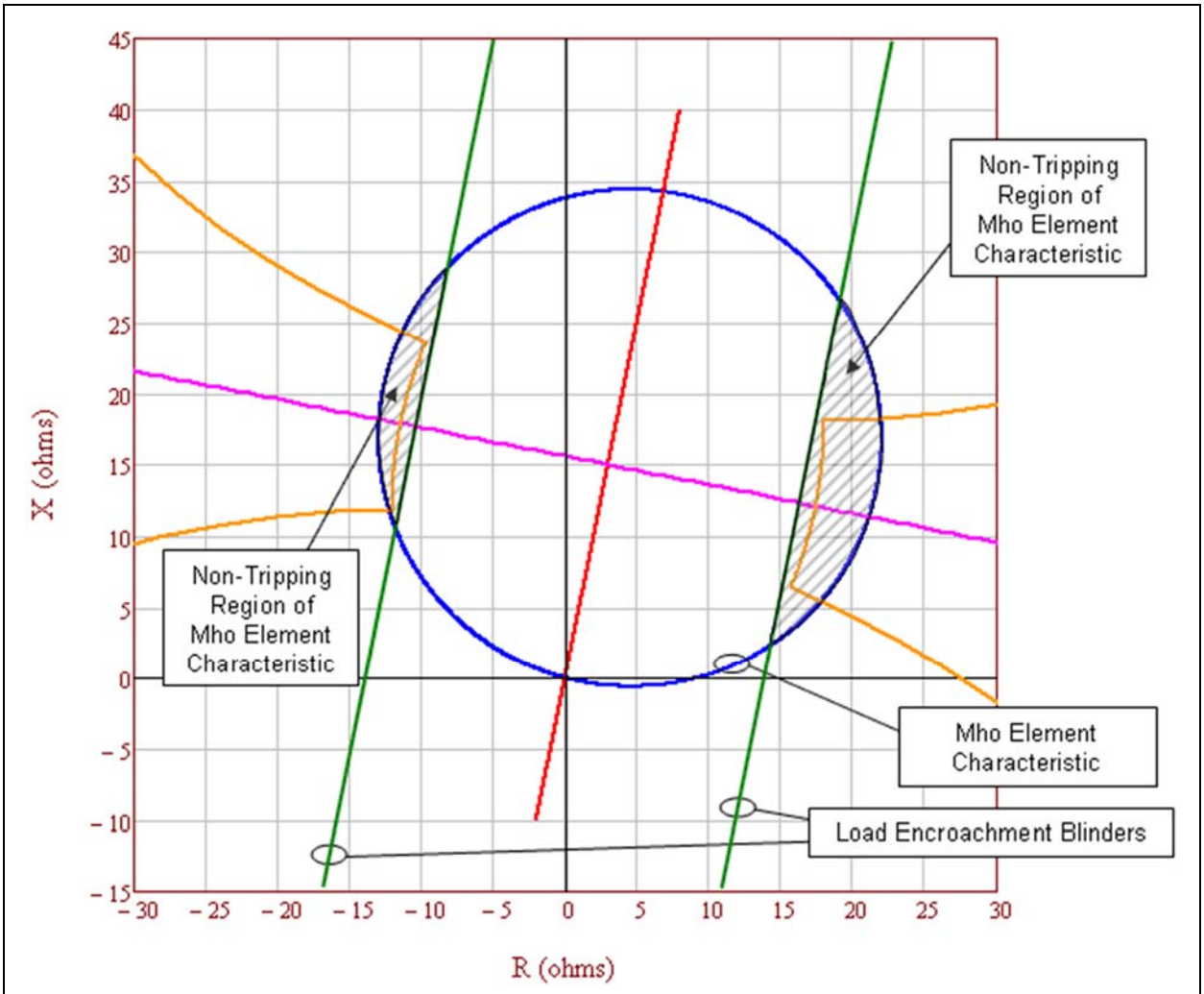


Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-1 – Attachment B, Criterion A.

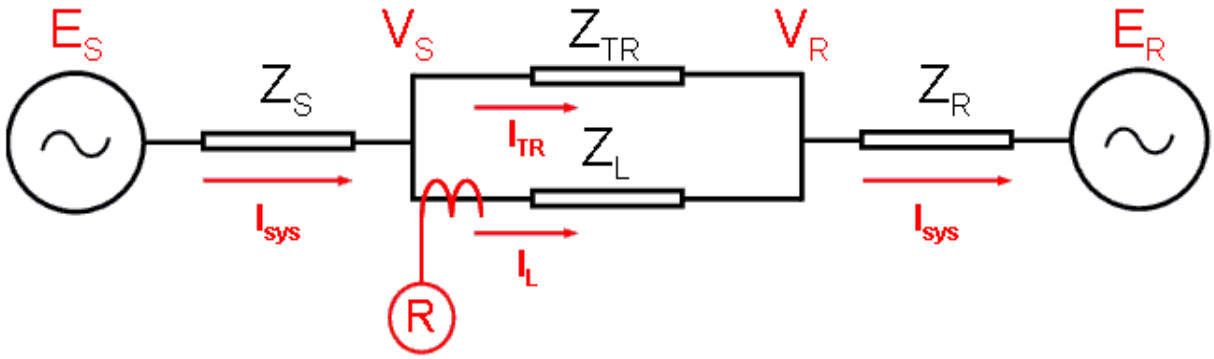


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

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)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

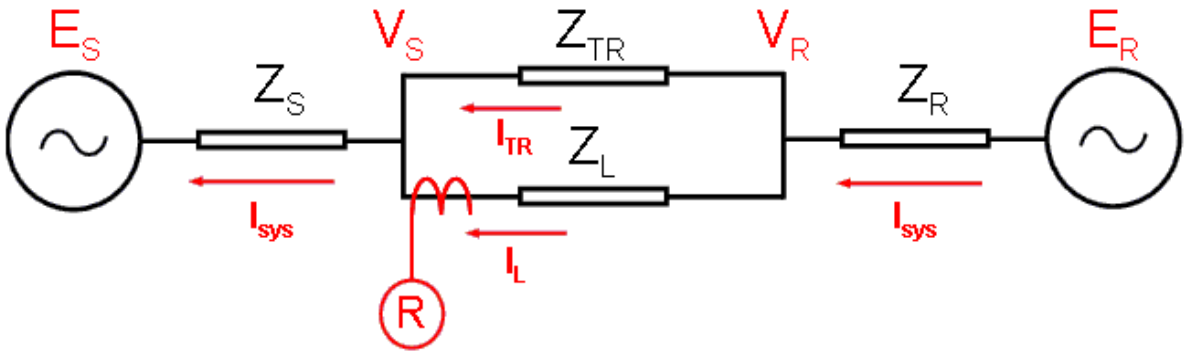


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

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.

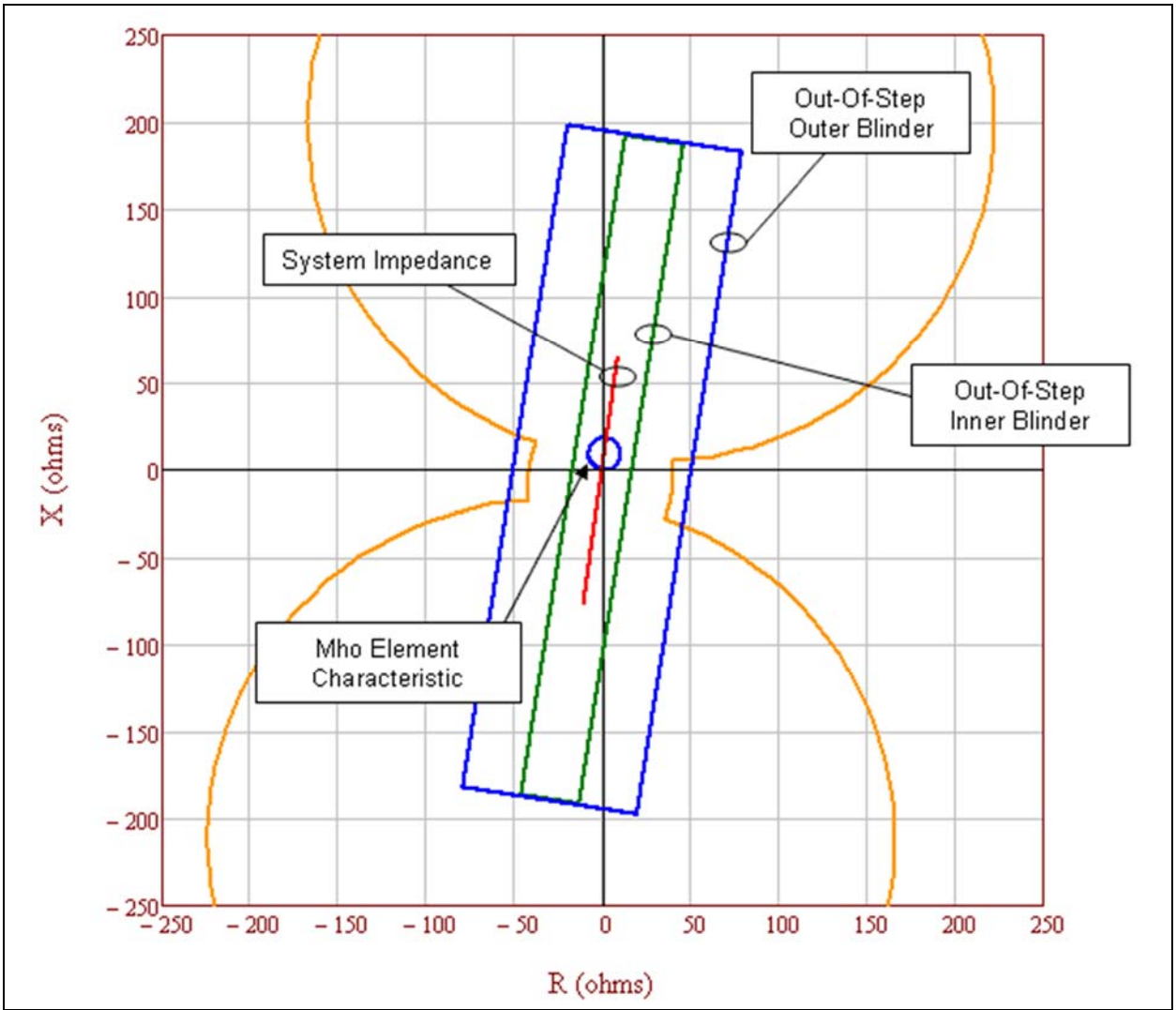


Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-1 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (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.[17] 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:	$E_S = 1.0$	$E_R = 0.7$	

[17] 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)	$r_b = \left\lvert \frac{N \times Z_{sys}}{N^2 - 1} \right\rvert$
	$r_b = \left\lvert \frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1} \right\rvert$
	$r_b = 69.987\ \Omega$

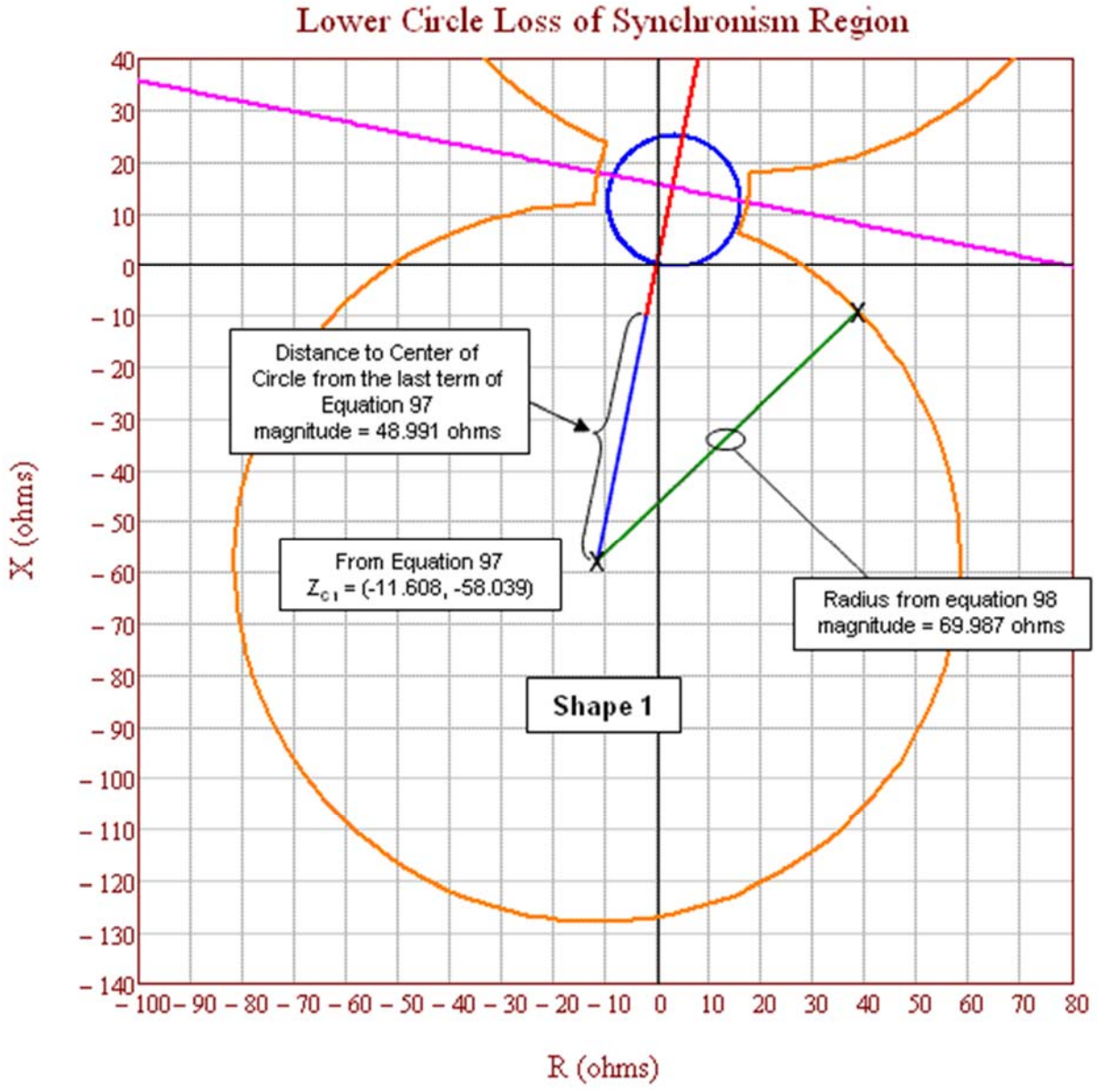


Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

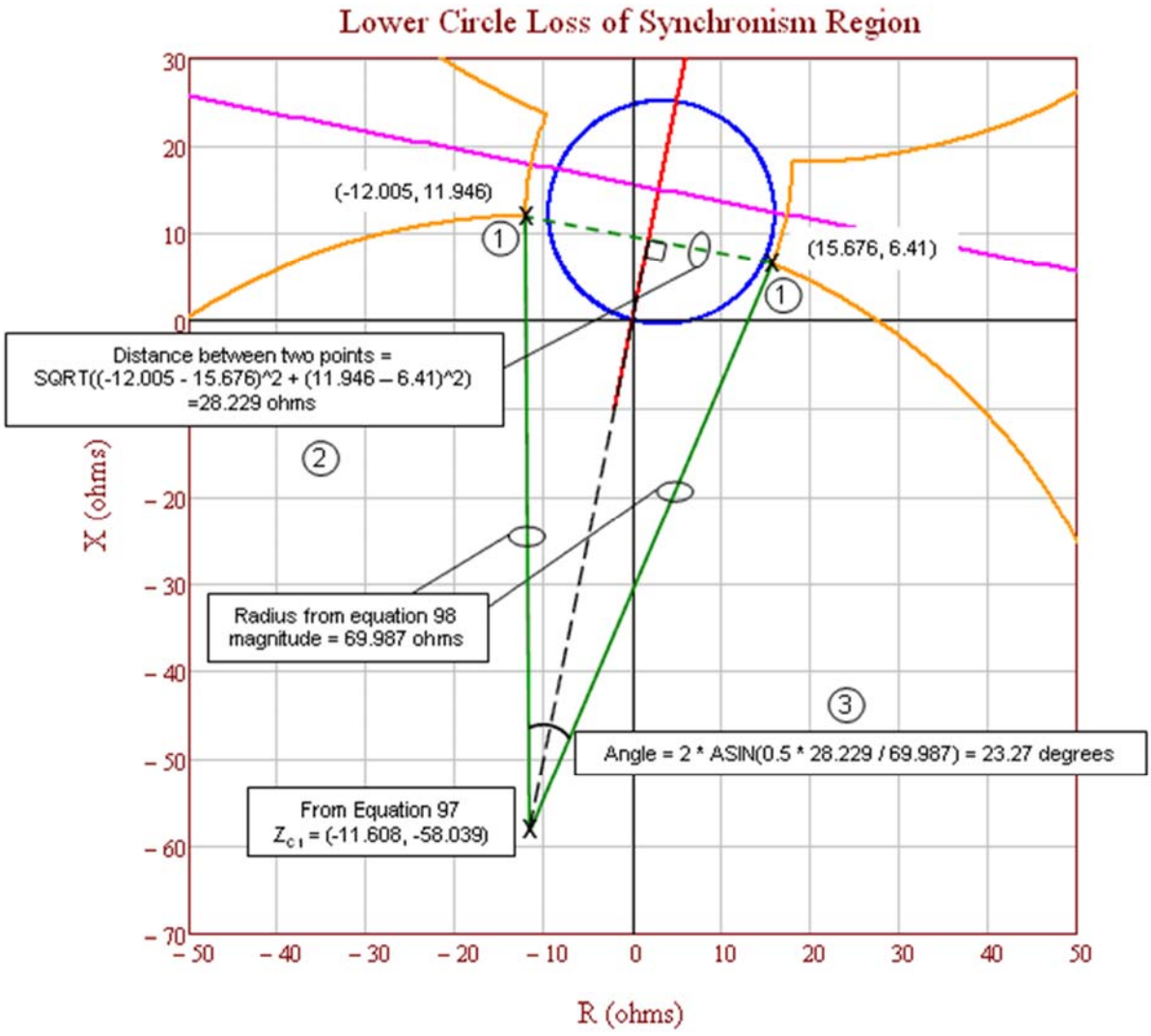


Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape 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.

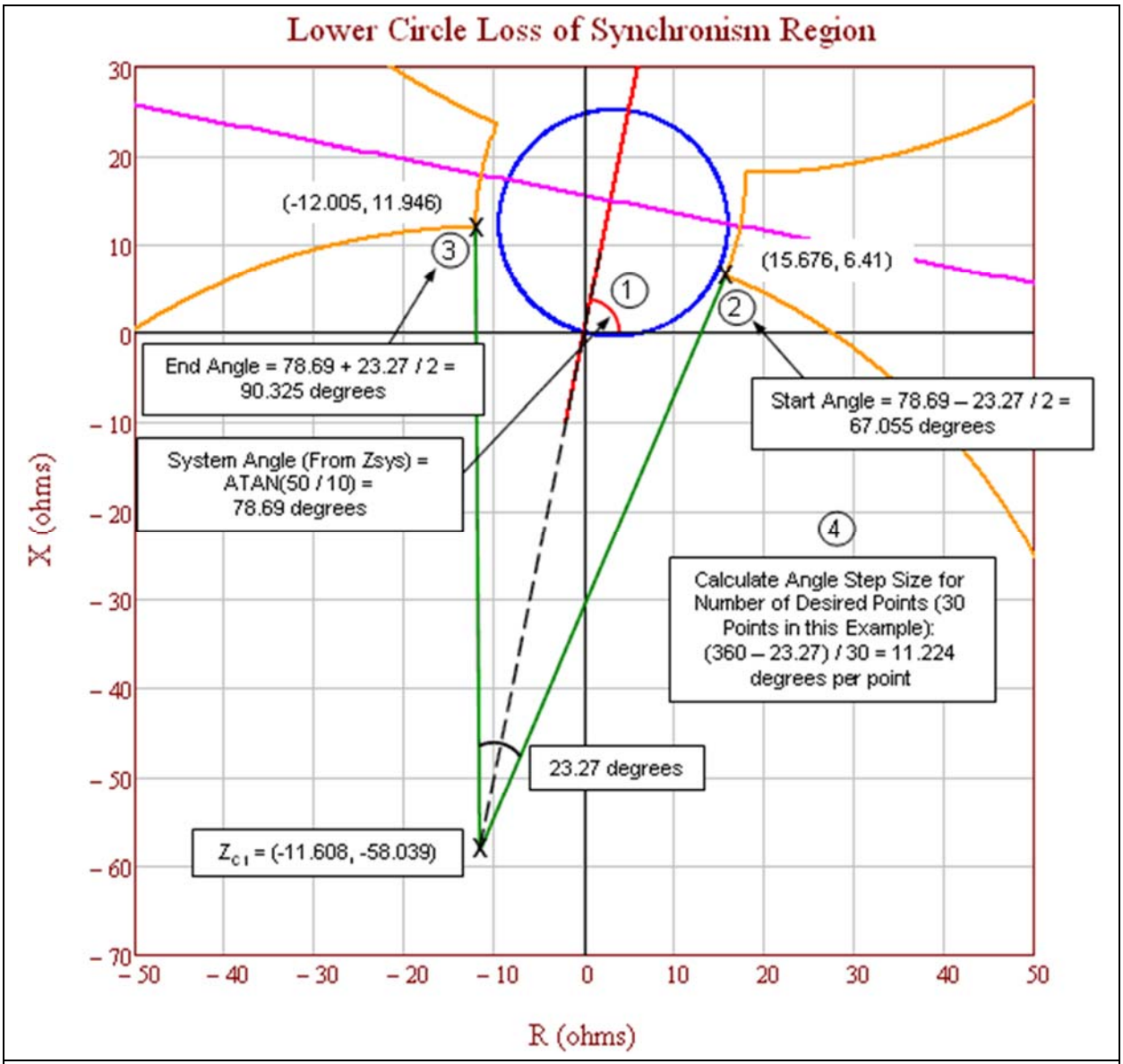


Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

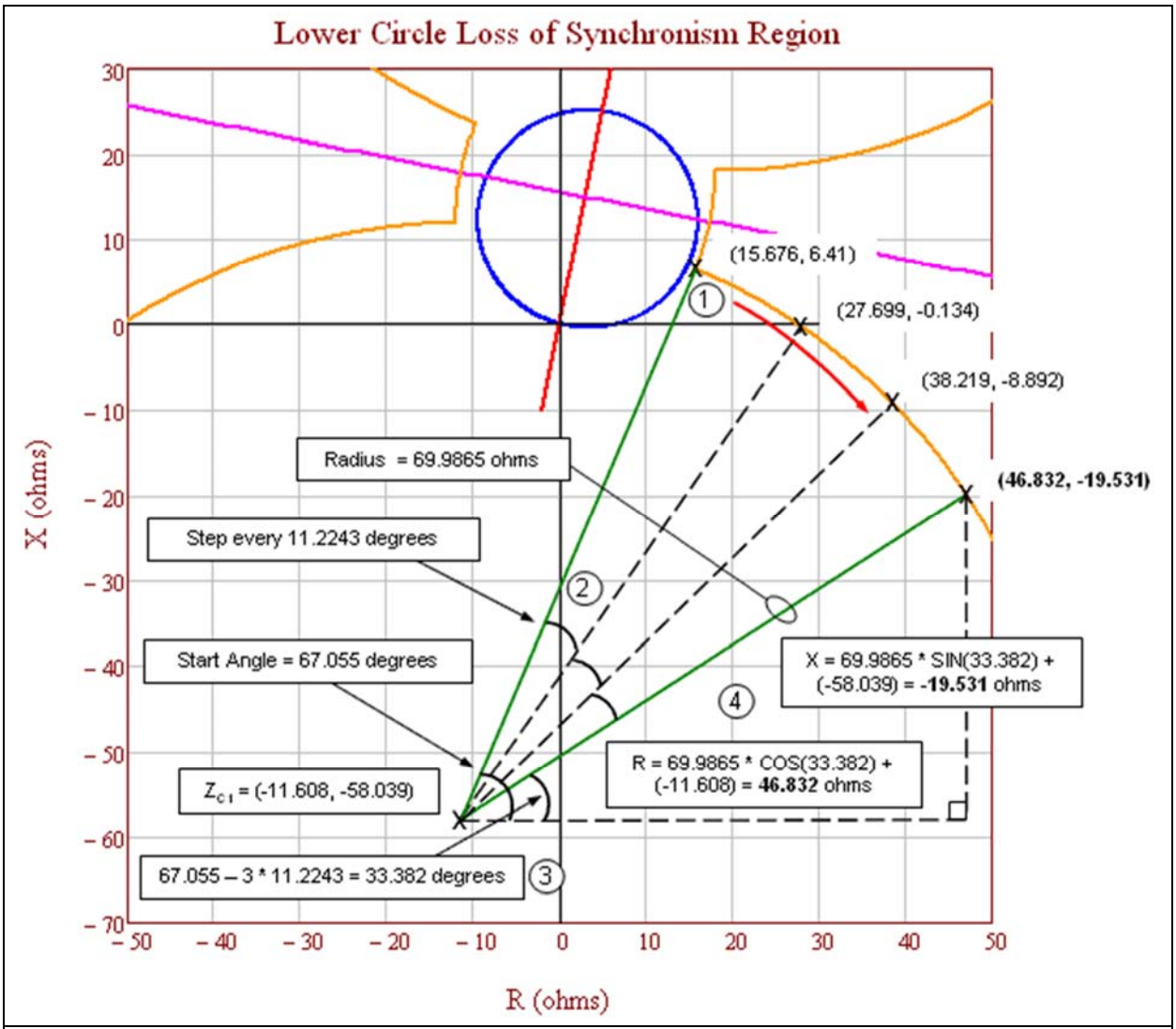


Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

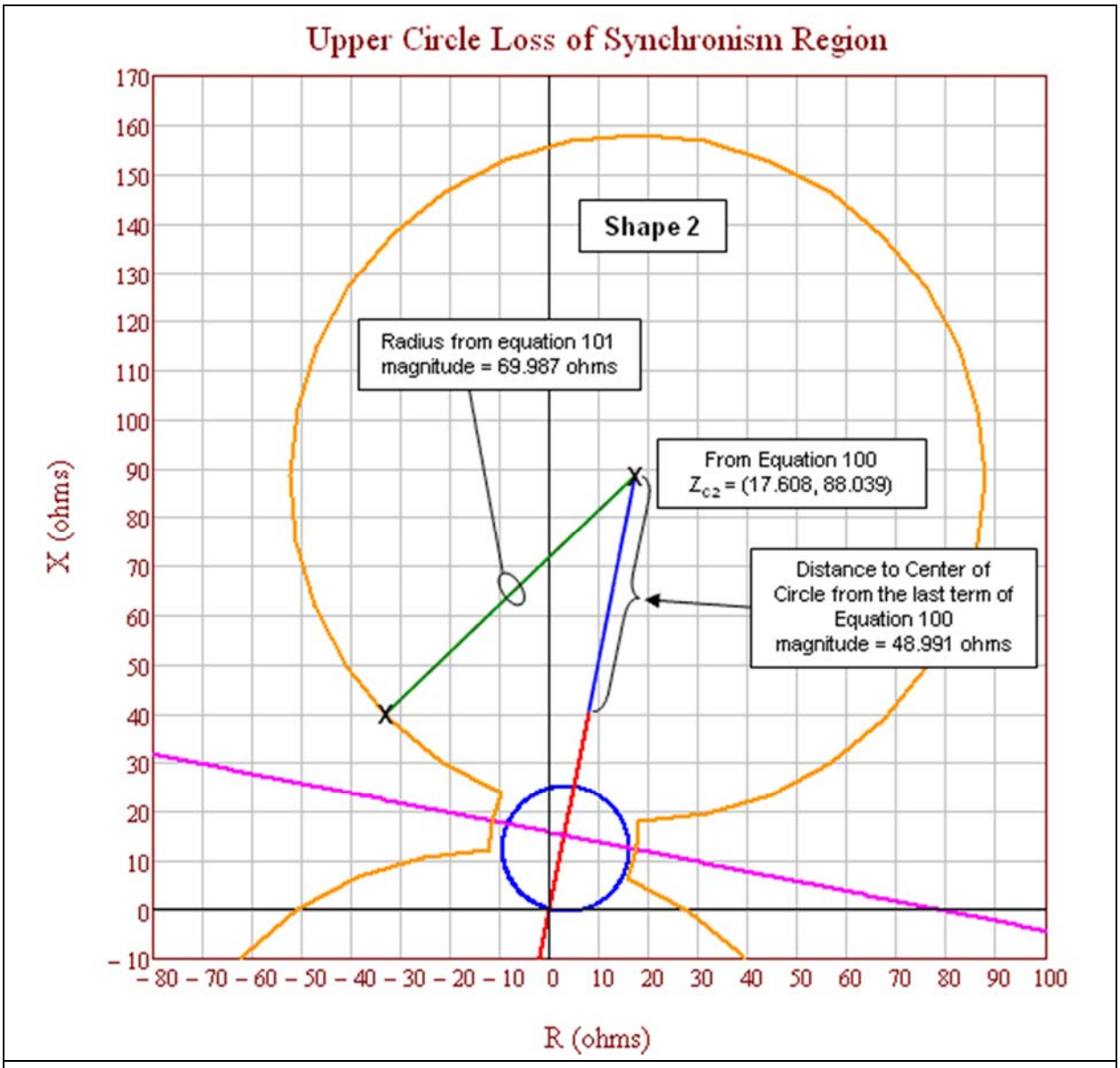


Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

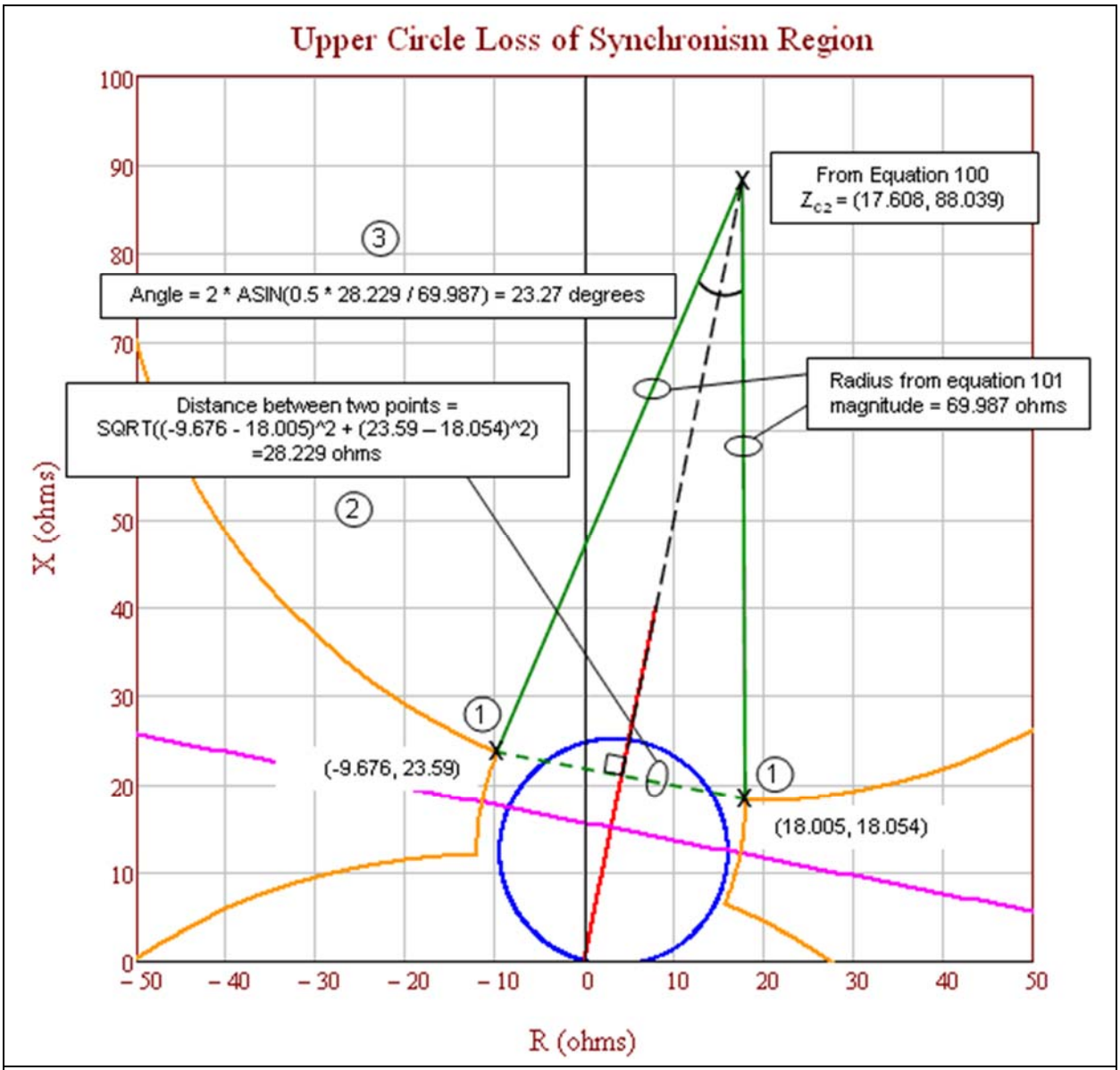


Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 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.

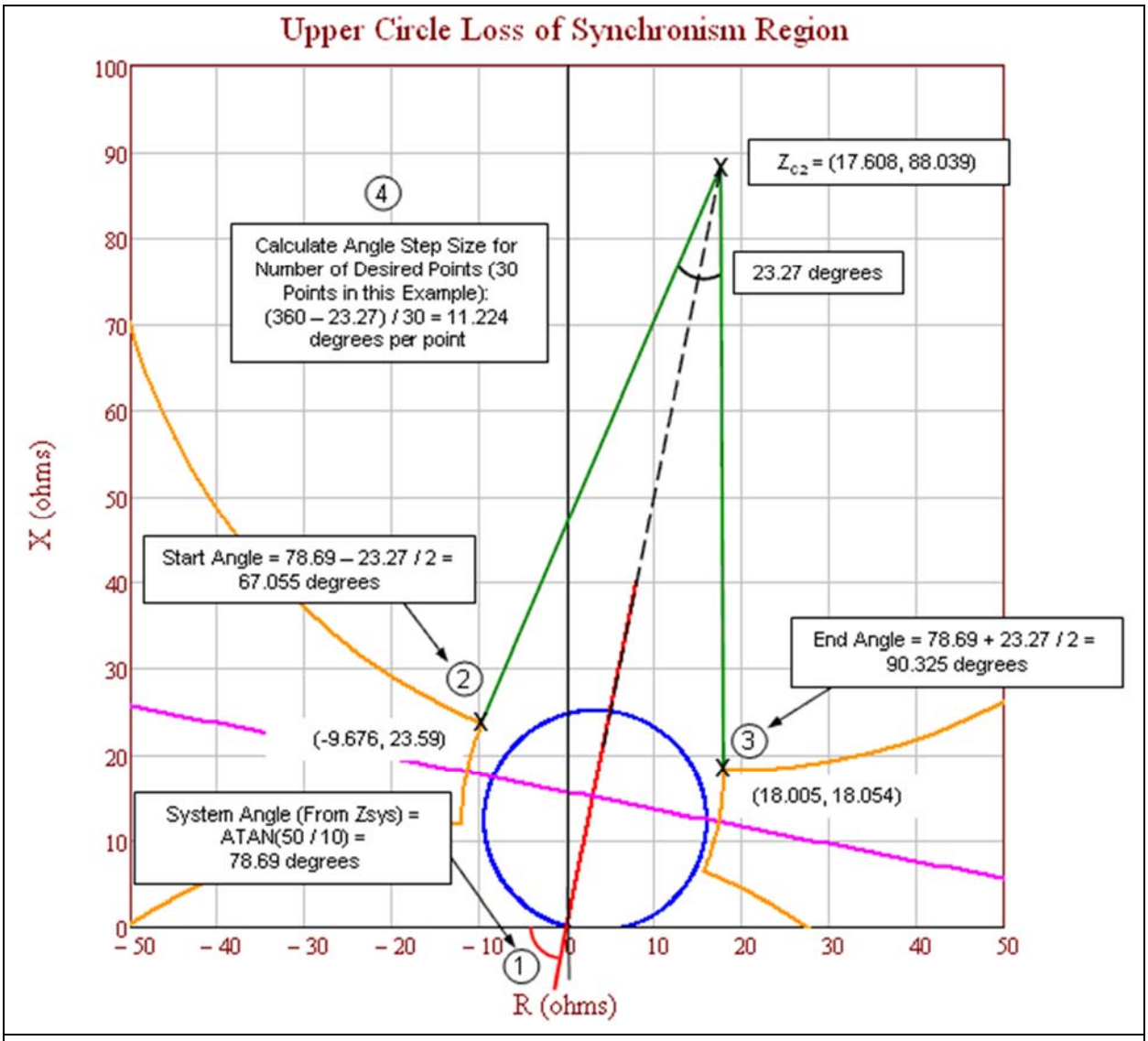


Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

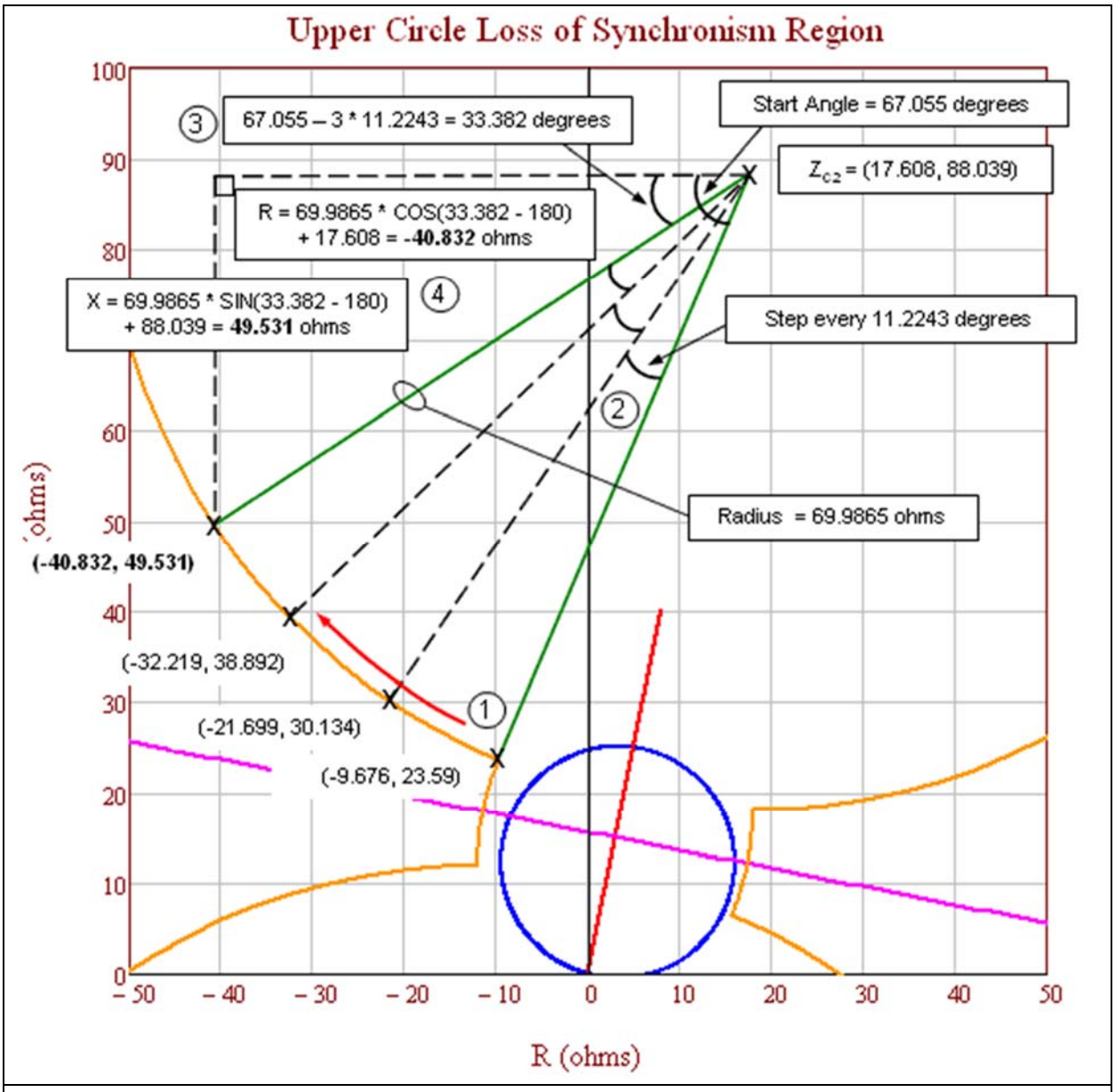


Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step 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).

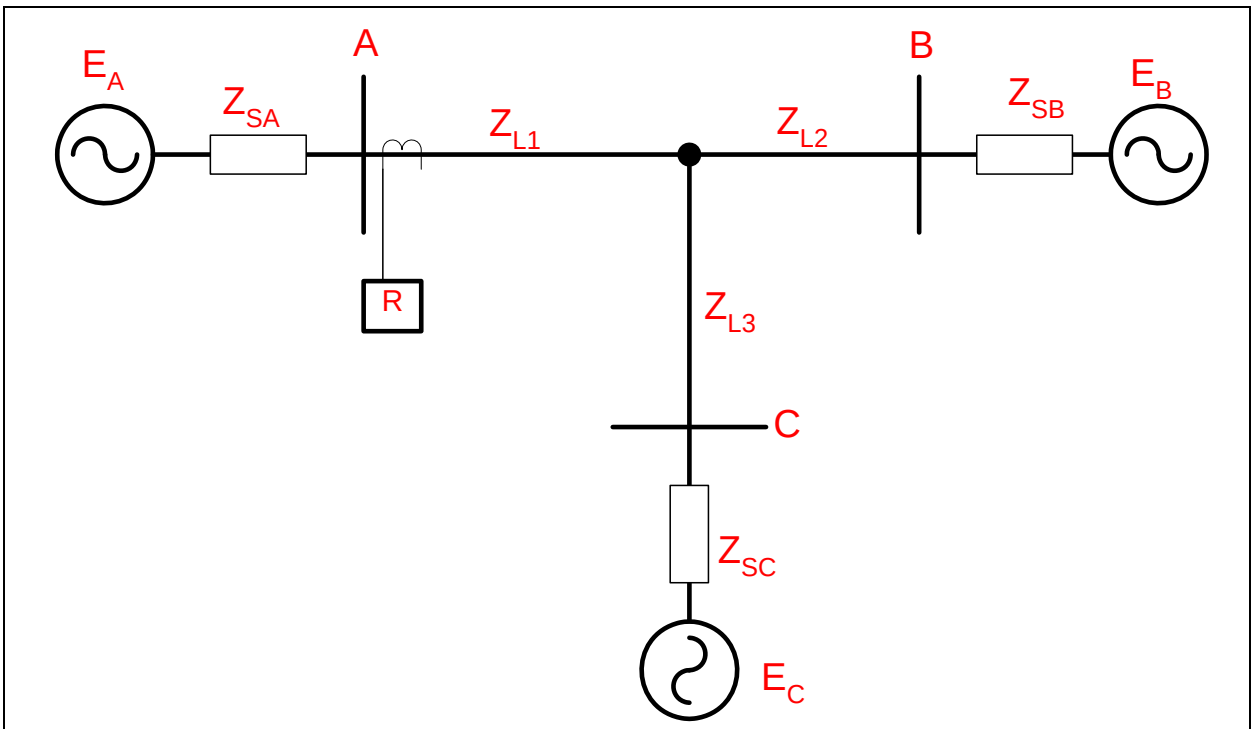


Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

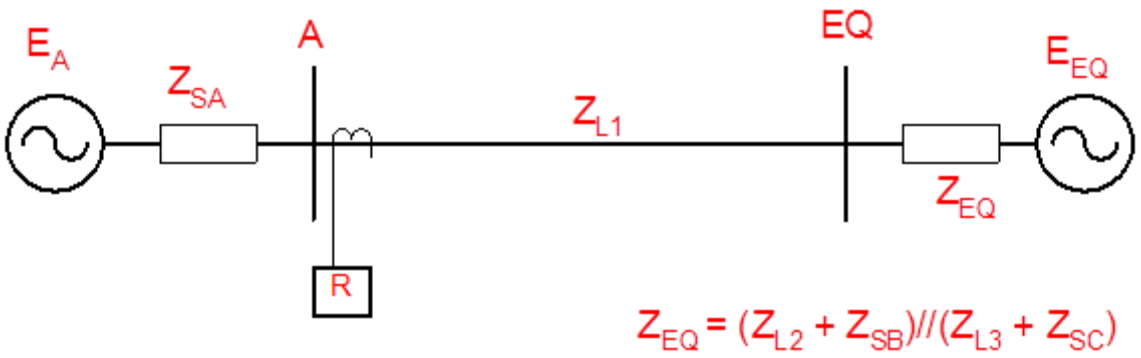


Figure 15k: Three-terminal line reduced to a two-terminal line.

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,[18,19] 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.[20] 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[21] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

[18] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[19] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[20] Ibid, Kundur.

[21] 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.[22] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

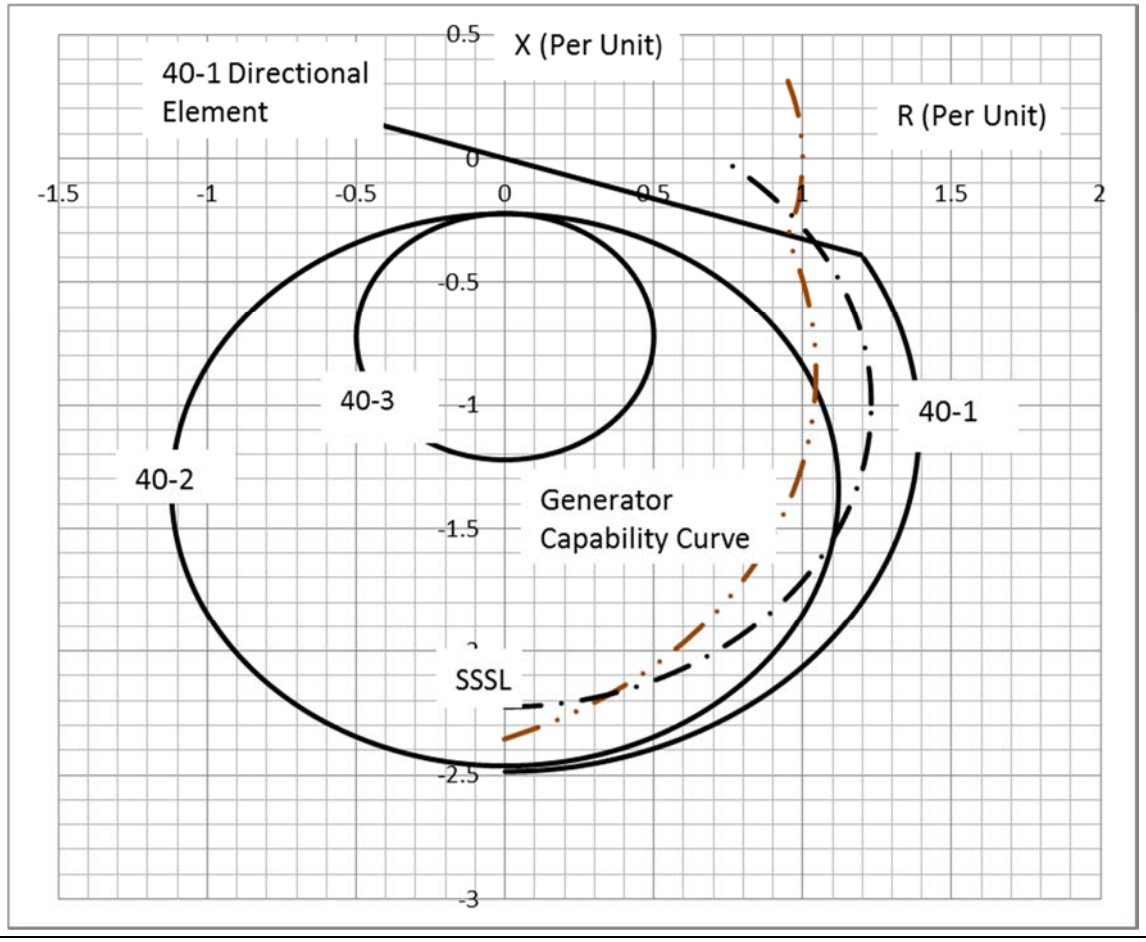


Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[22] 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[23] 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[24,25] 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.[26] 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.[27] 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.

[23] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[24] Ibid, Burdy.

[25] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[26] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[27] Ibid, Kimbark.

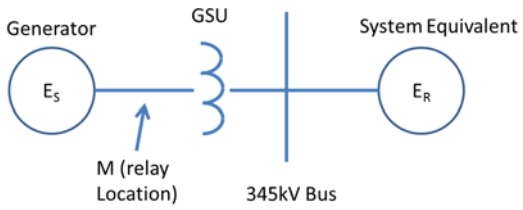


Figure 17: Simple one-line diagram of the system to be evaluated.

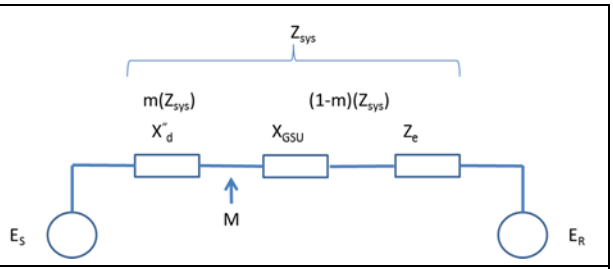


Figure 18: Simple system equivalent impedance diagram to be evaluated.[28]

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°

[28] 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:[29]

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)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163) \times (1\angle 120°) + (0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\ pu$		

[29] 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.

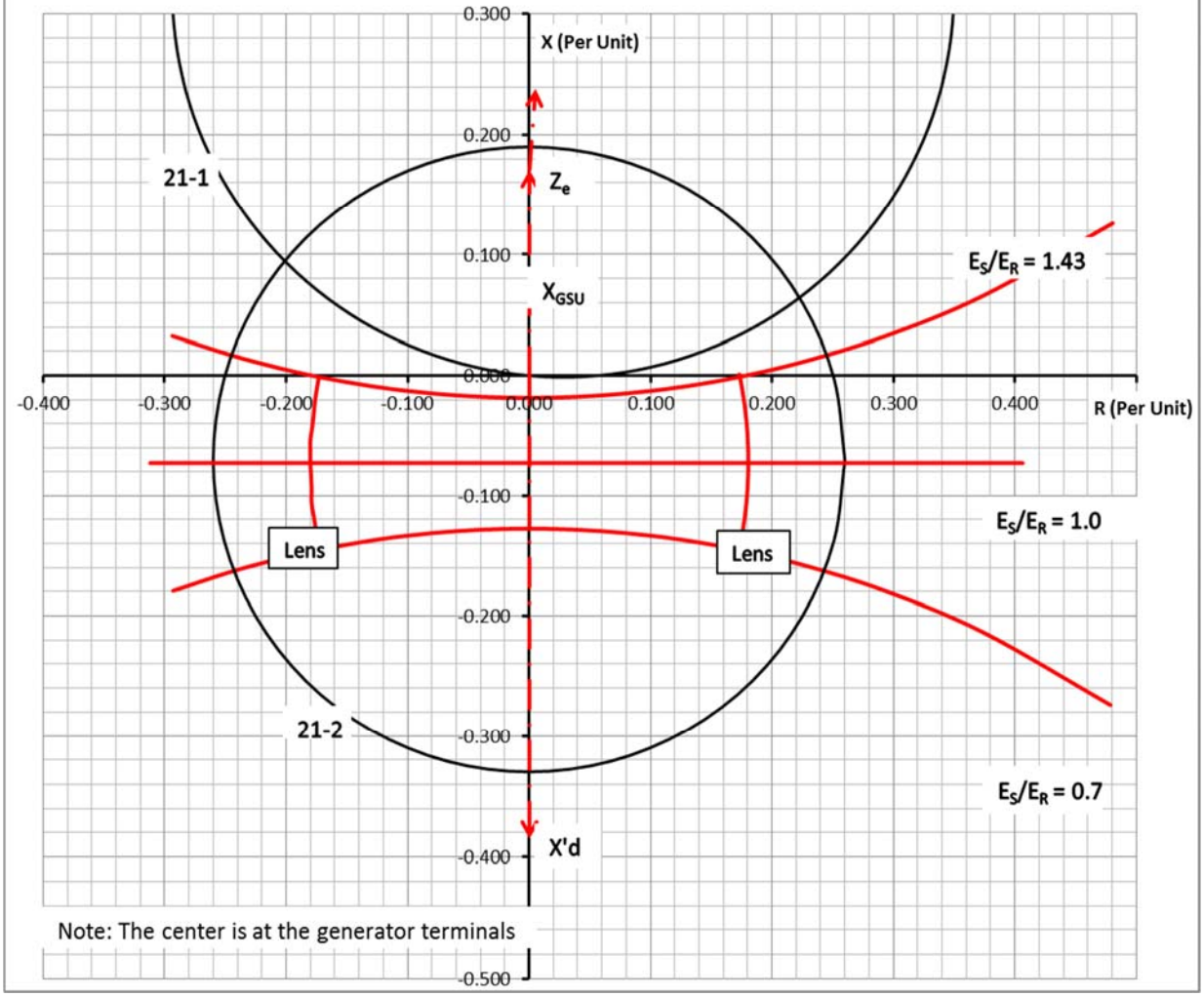


Figure 19: Swing impedance graph for impedance relays at a generating facility.

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.

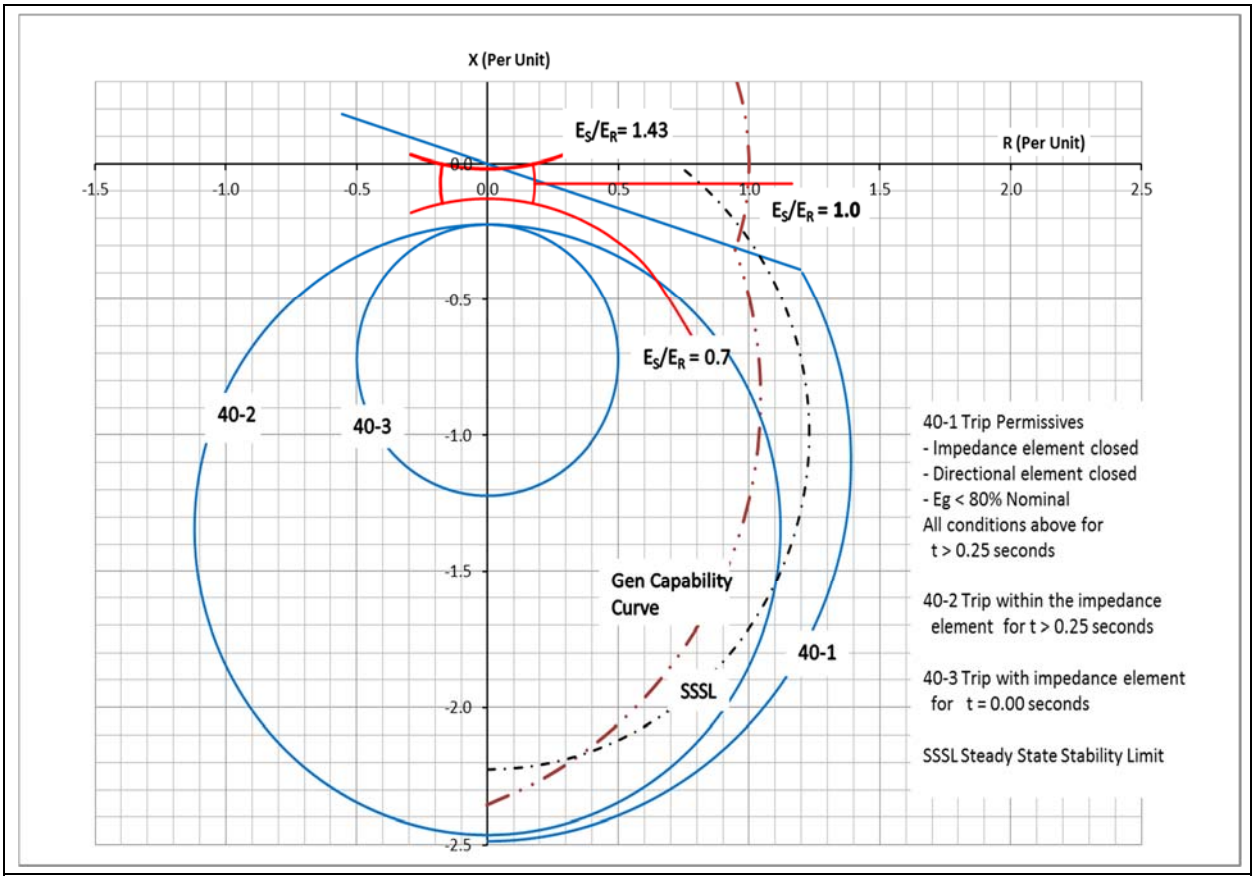


Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-1 – Attachment B, Criterion A.

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.

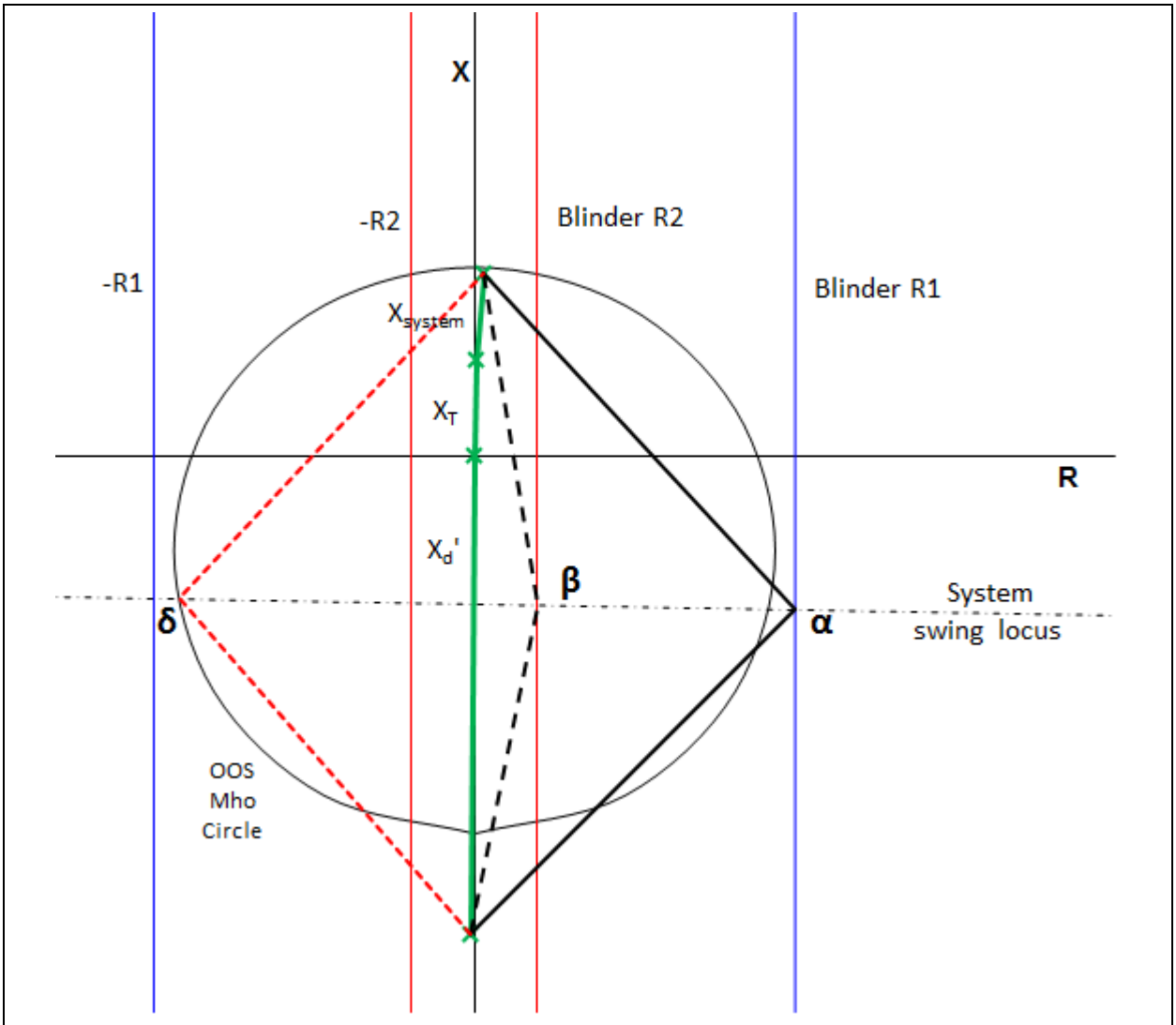


Figure 21: Double Blinder Scheme generic out of step characteristics.

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.

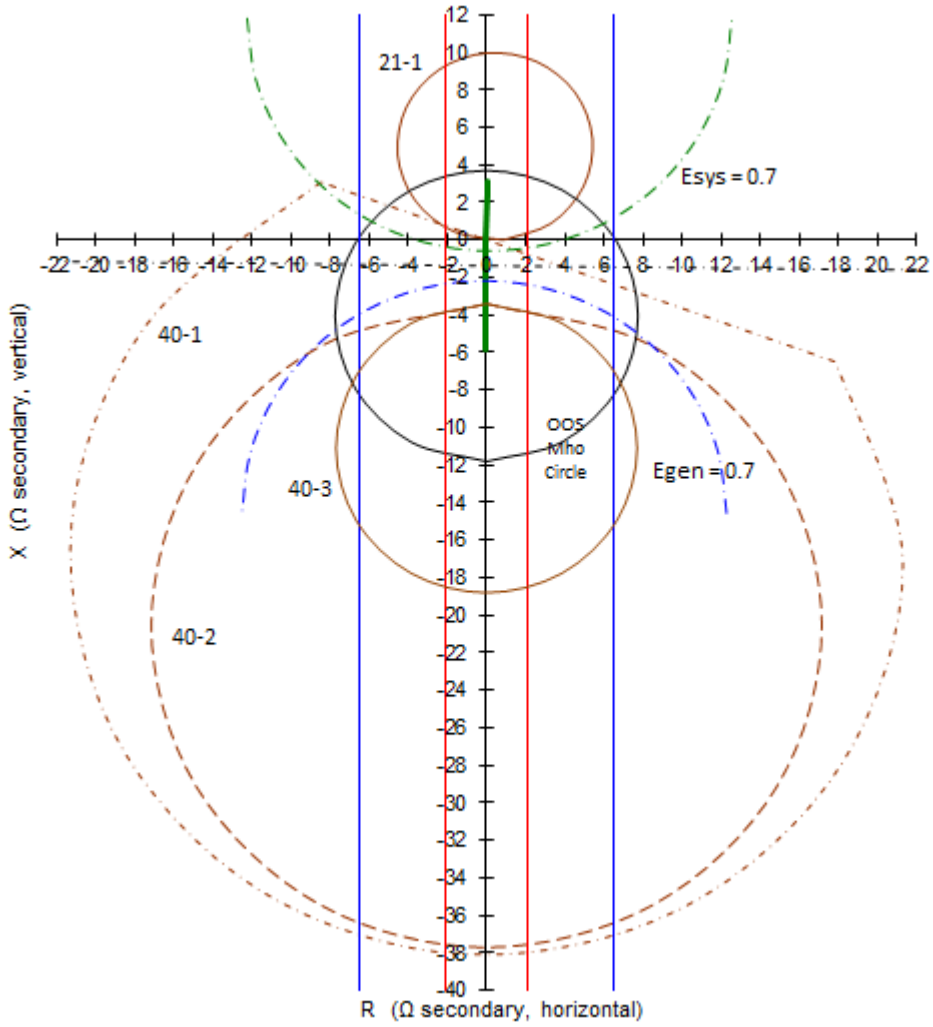


Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

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.

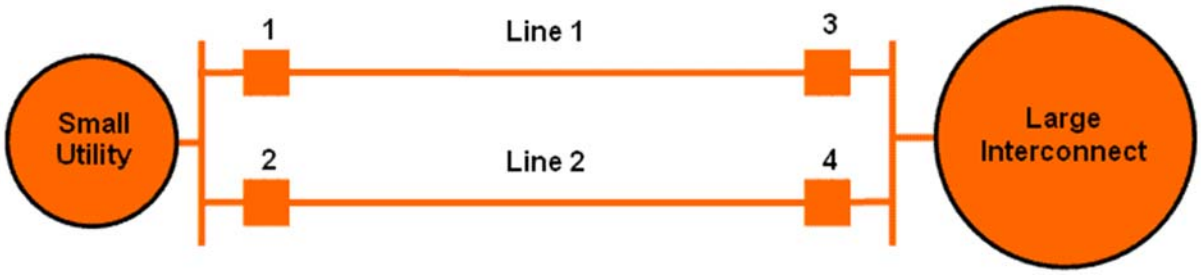


Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

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.

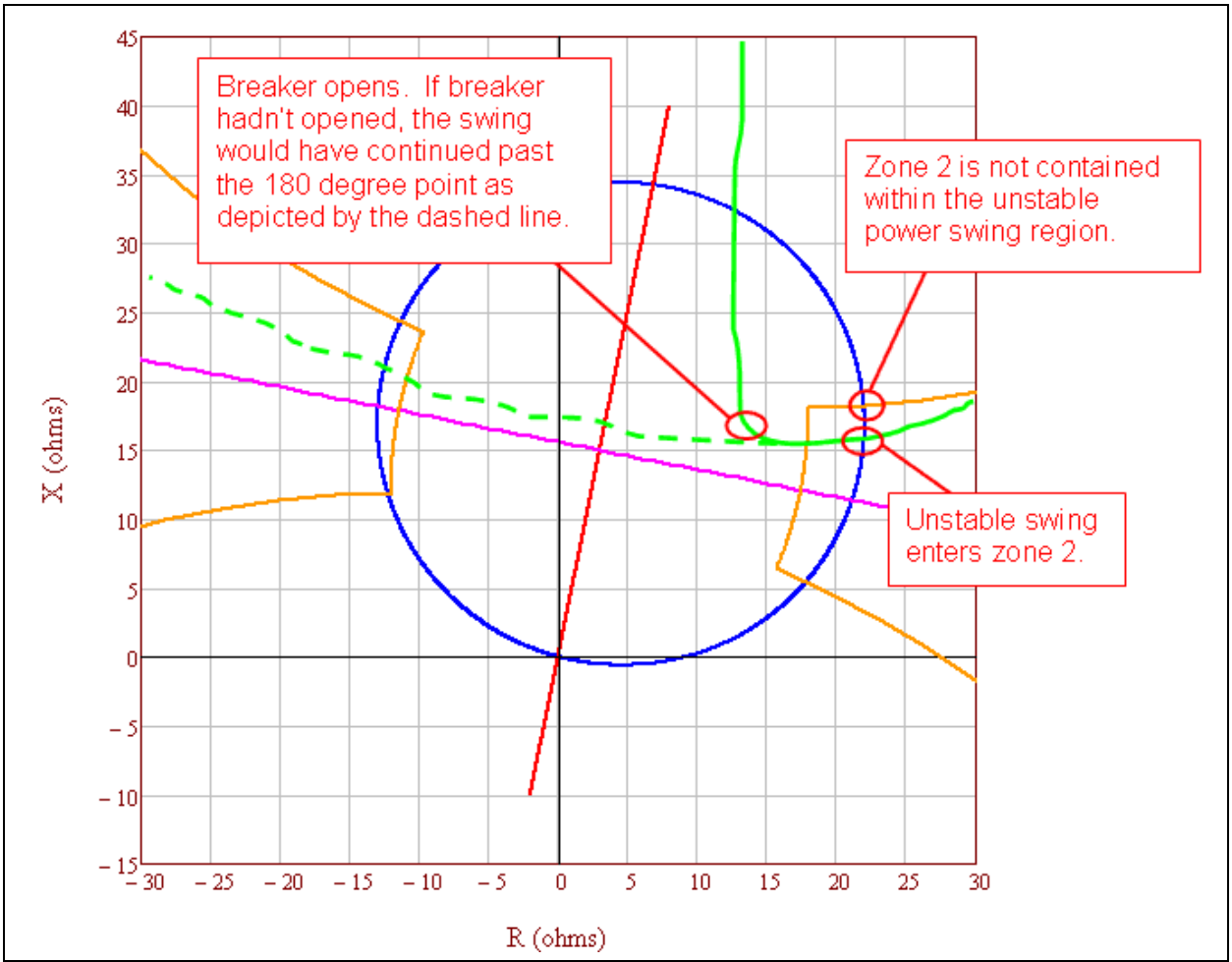


Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-1 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

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.

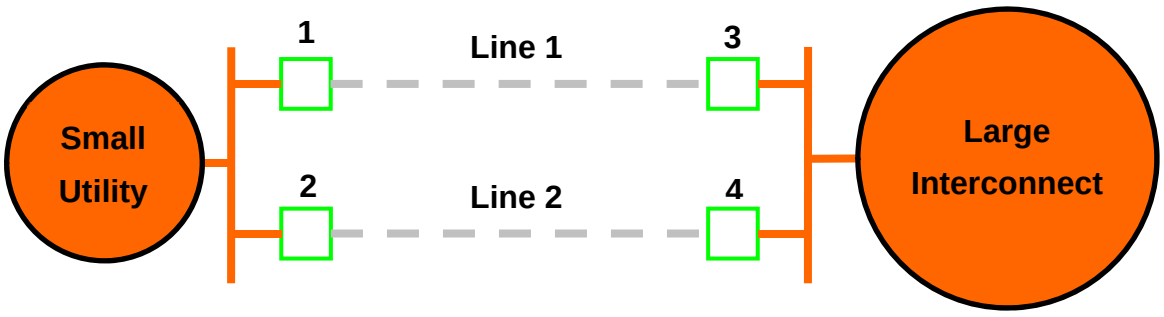


Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

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.

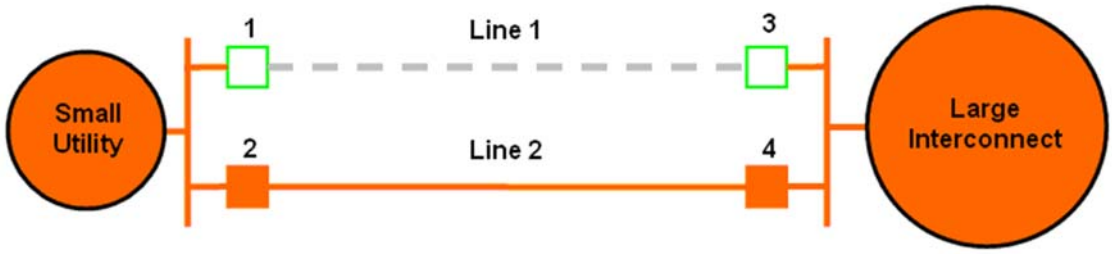


Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

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.

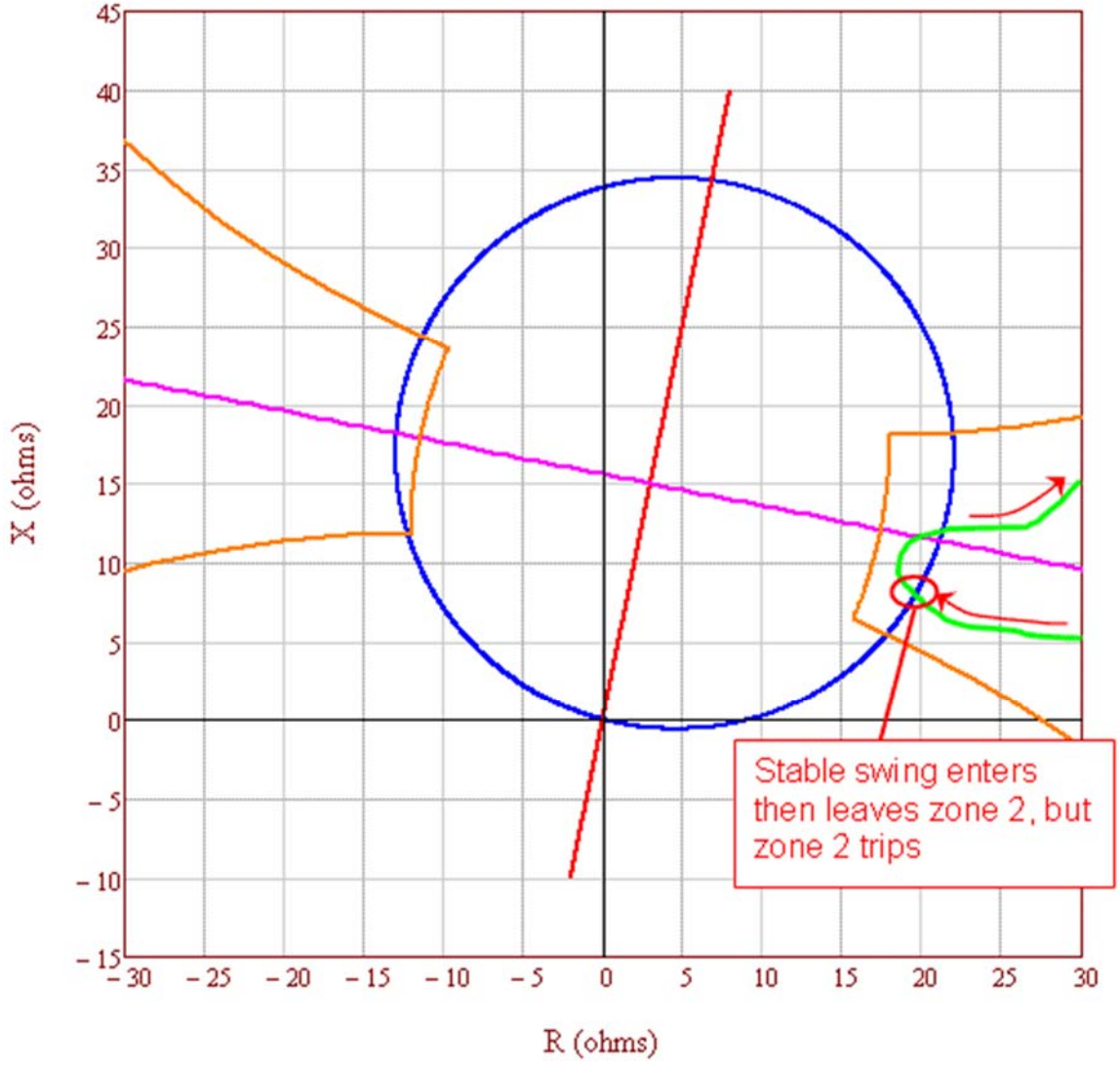


Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-1 – Attachment B criteria following the previous unstable power swing event.

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.

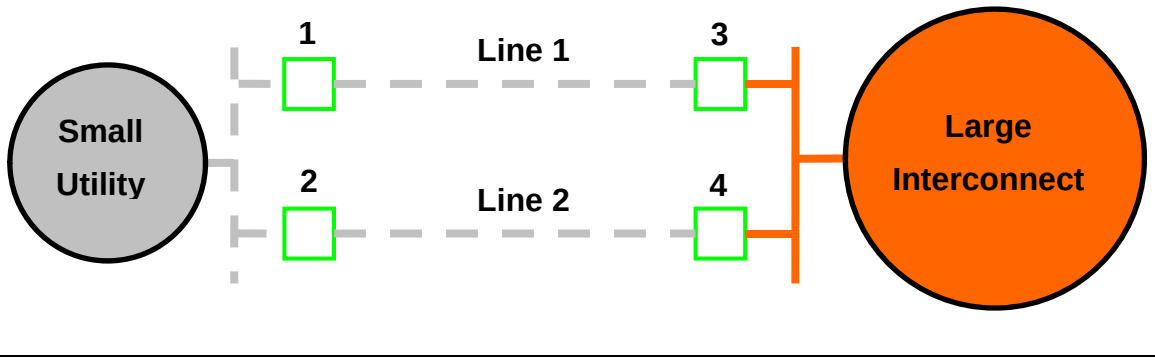


Figure 28: Possible blackout of the small utility.

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"),[30] 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

[30] 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).

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.

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Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

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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.

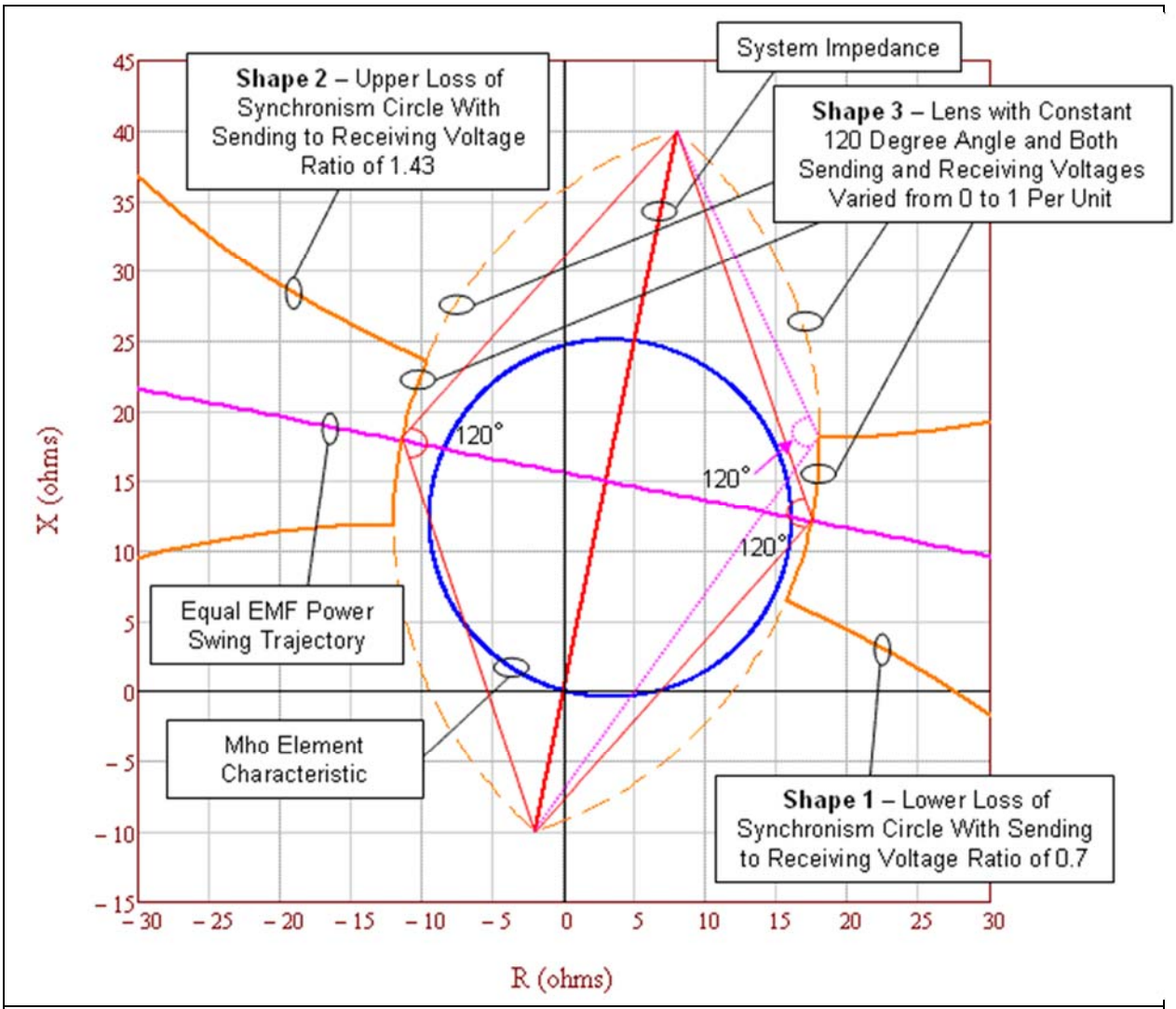


Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained 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.

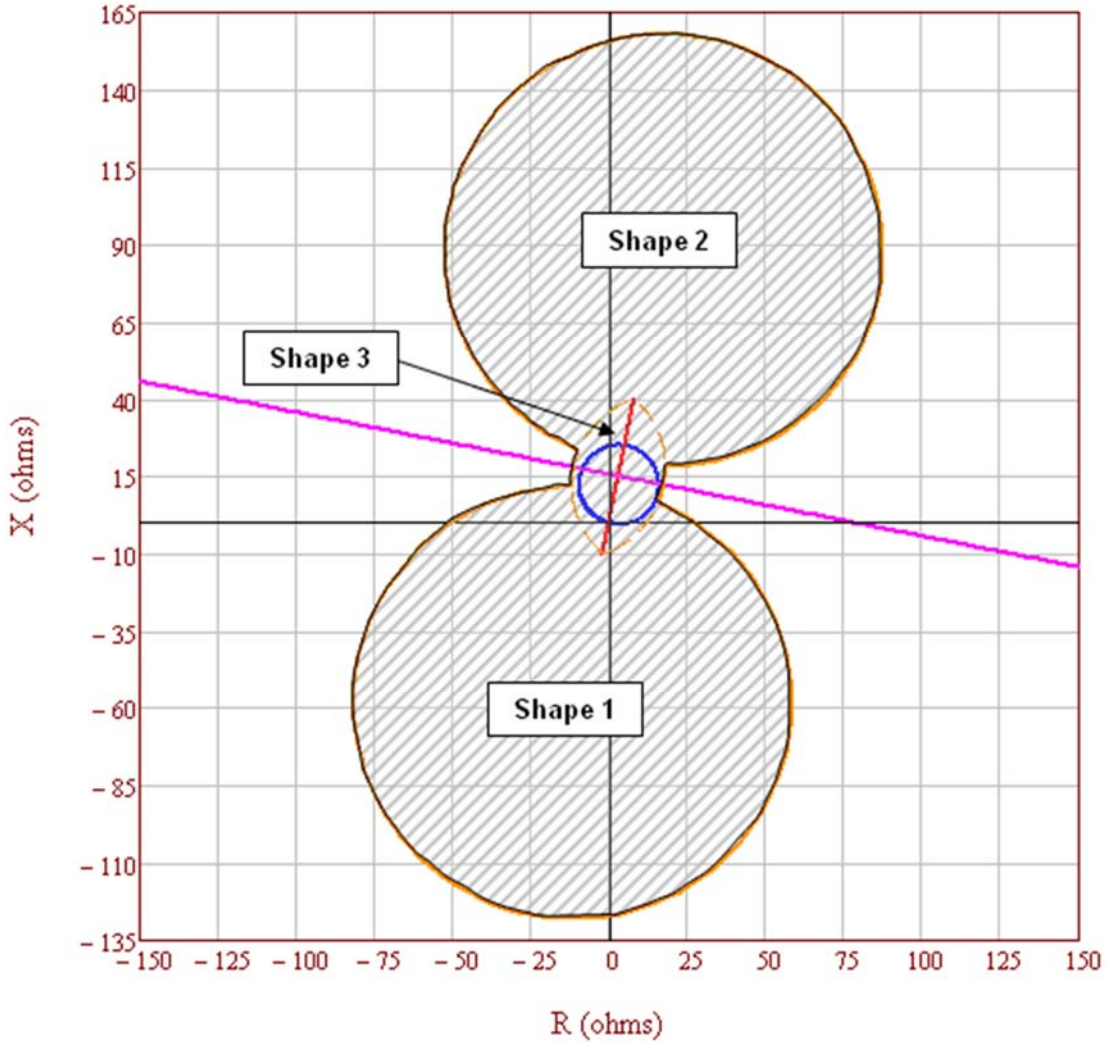


Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

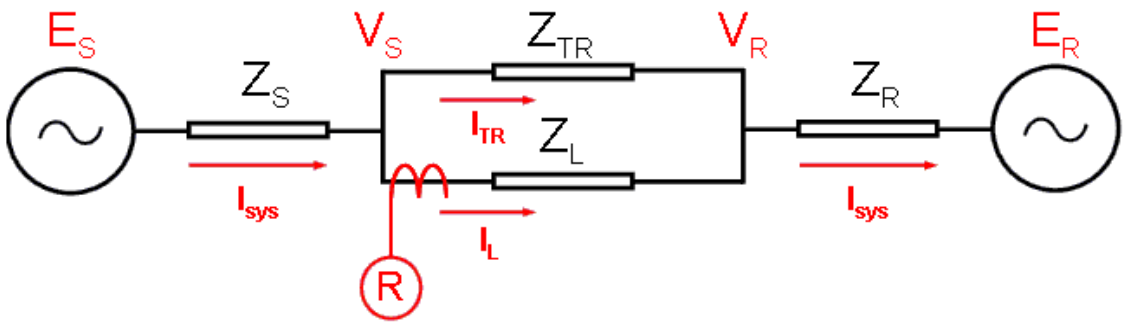


Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

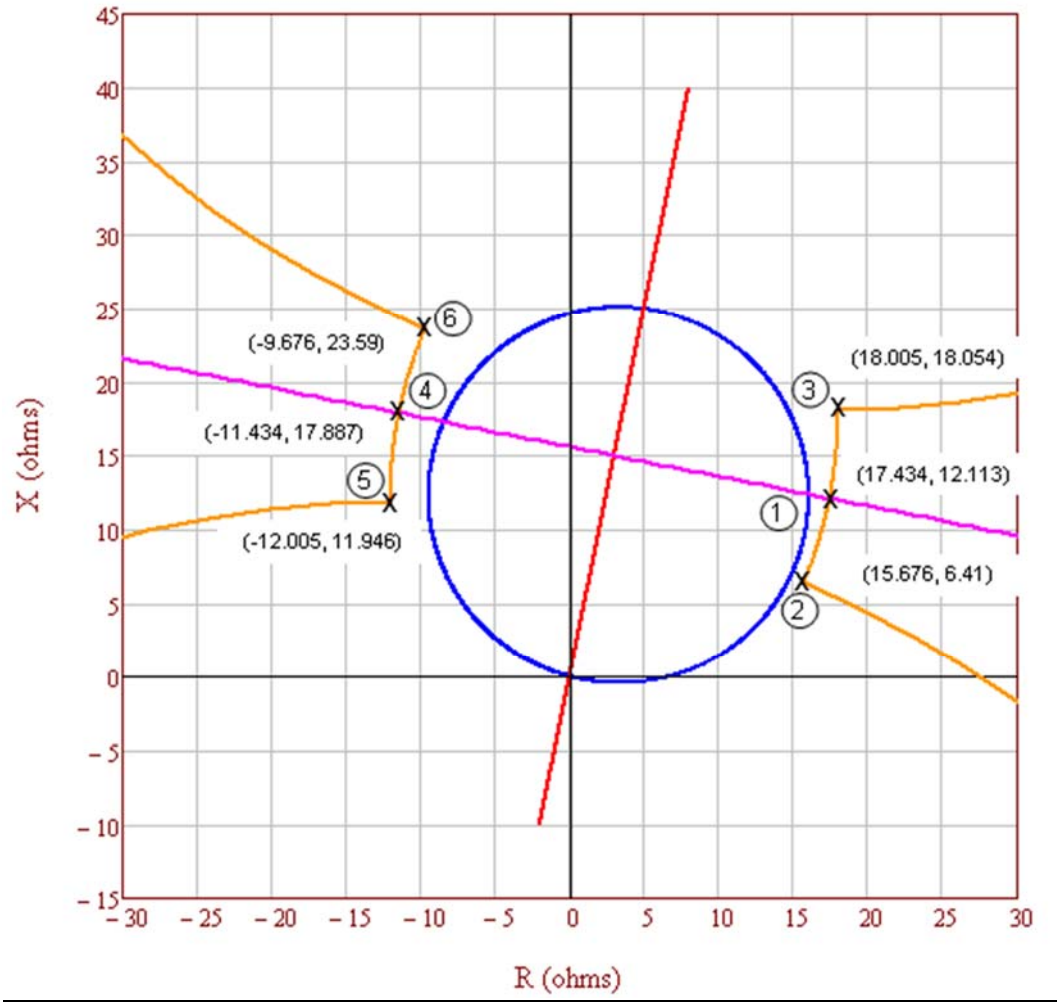


Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	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)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle -110.6° \, V}{3{,}854\angle 137.1° \, A}$
	$Z_{L-Relay} = -9.676 + j23.59 \, \Omega$

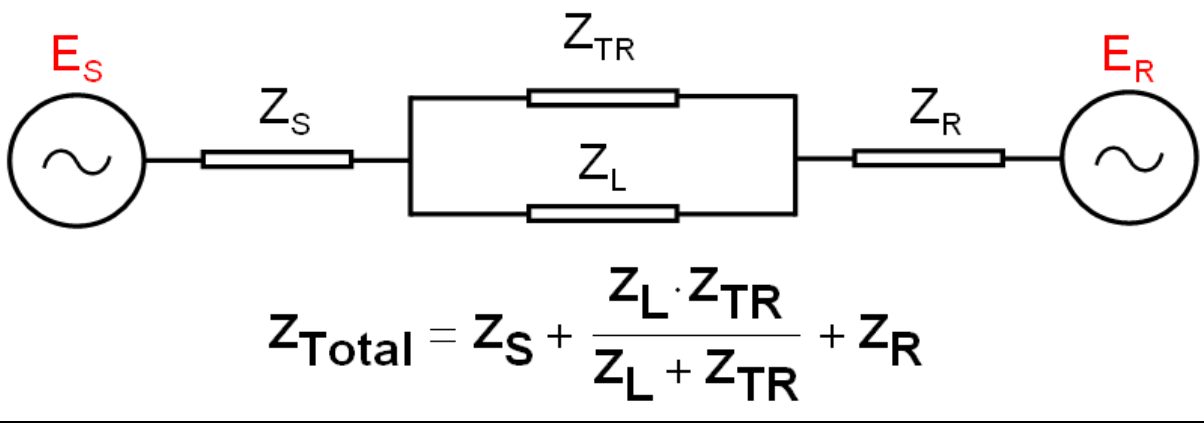


Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.

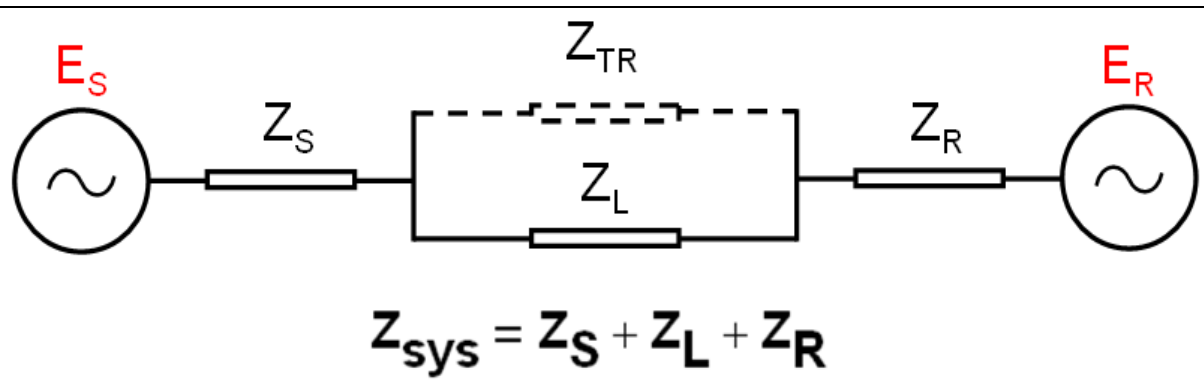


Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

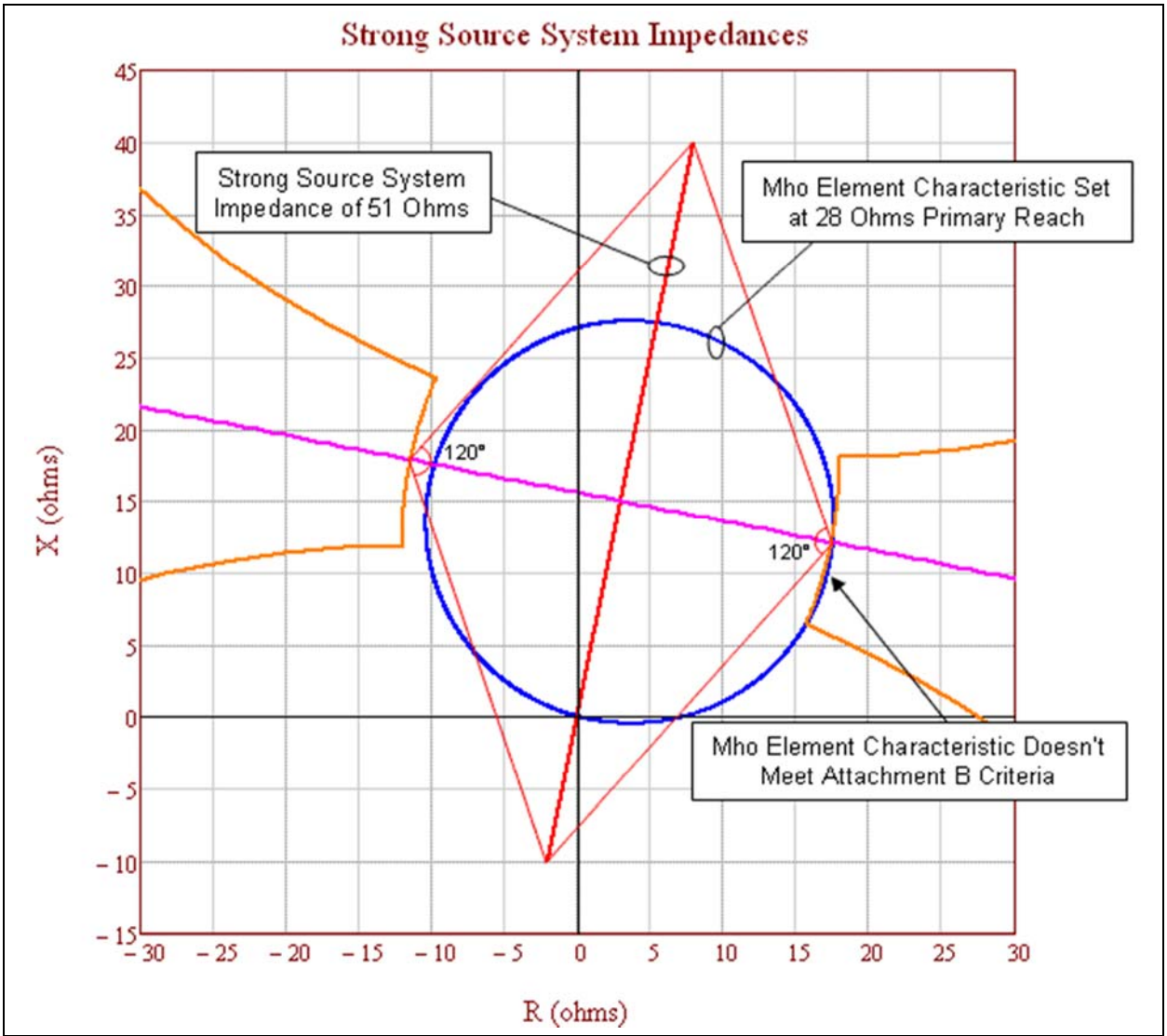


Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., 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.

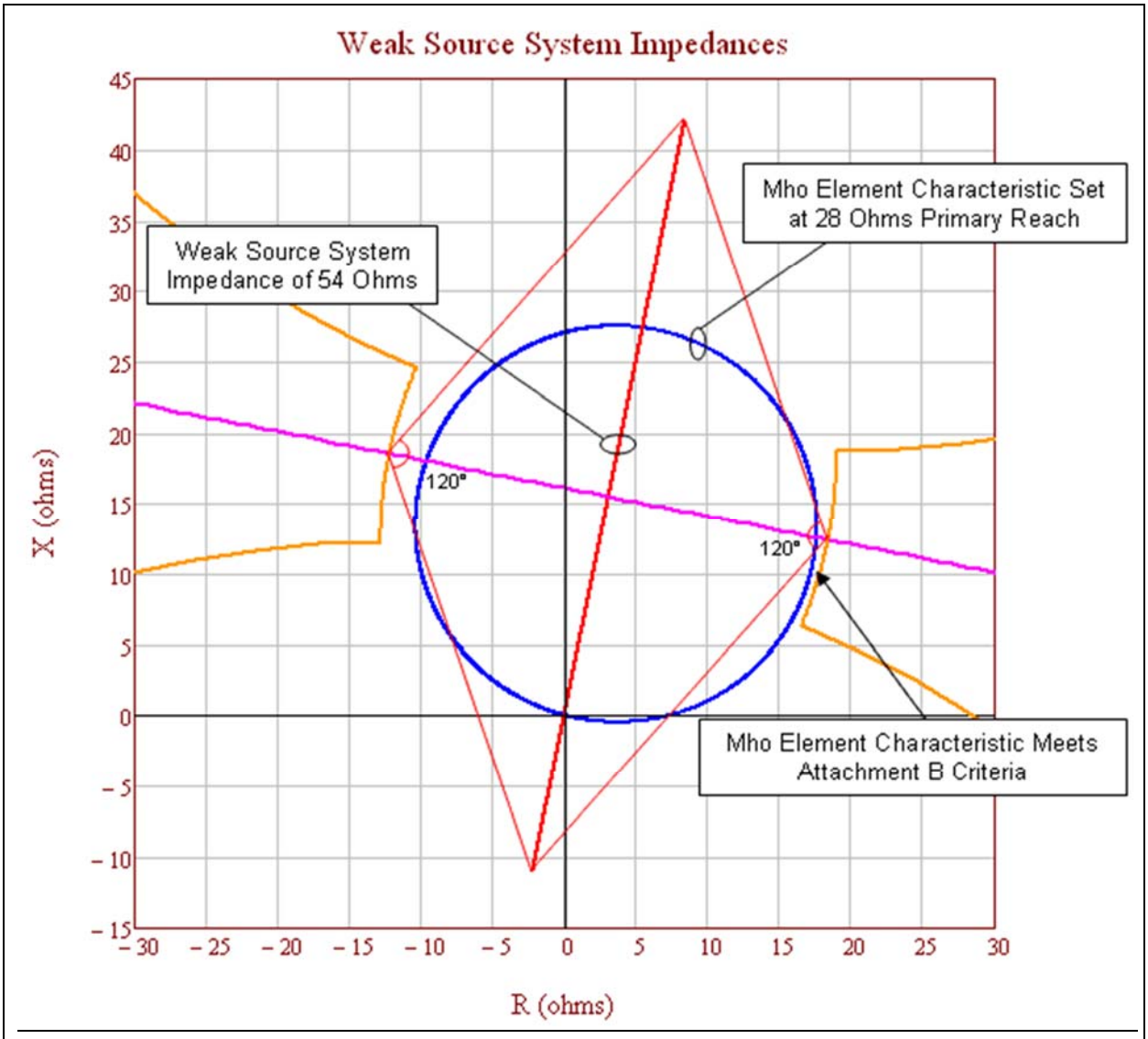


Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

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.

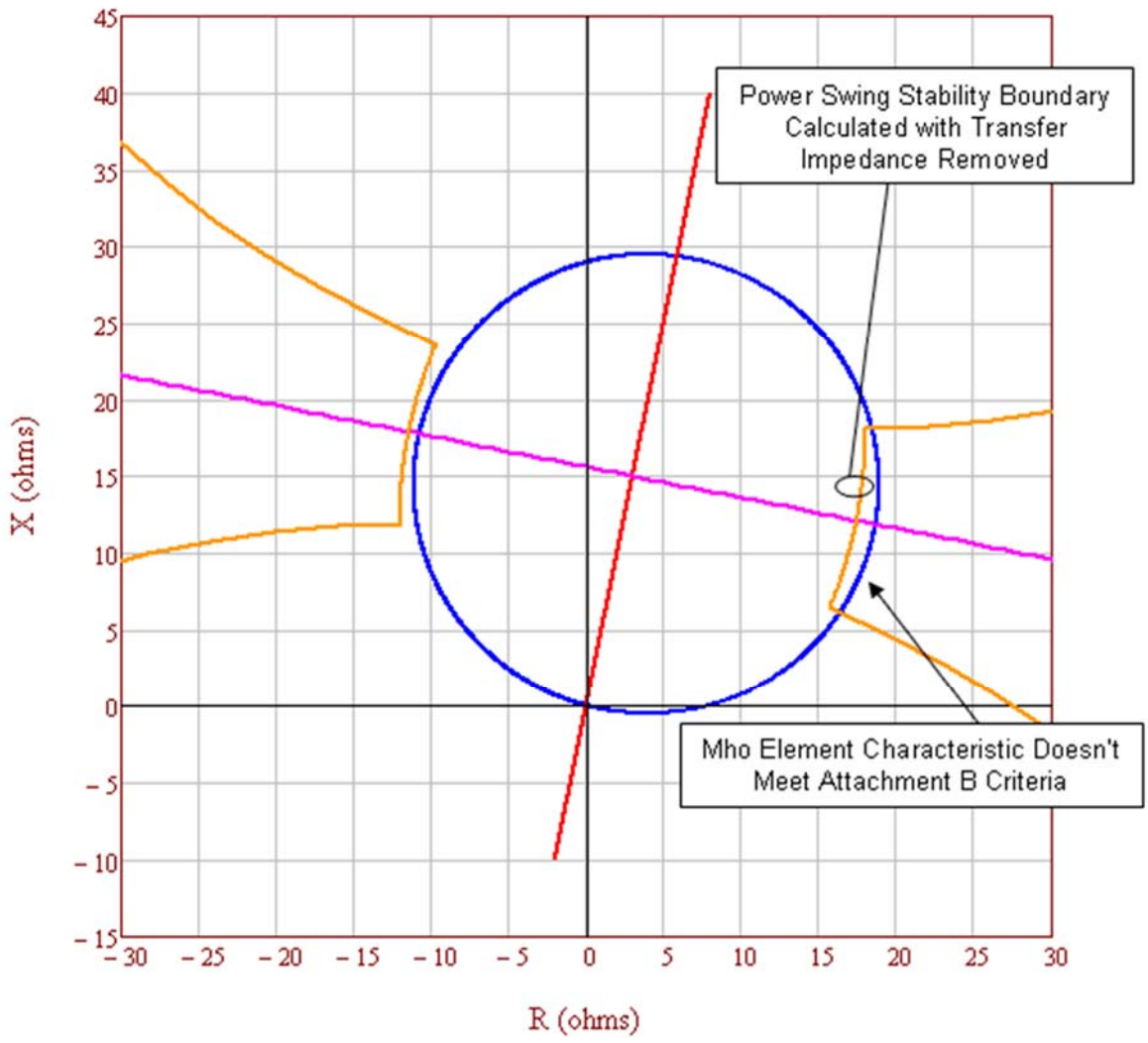


Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-1 – Attachment B, Criterion A because it is not completely contained within 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)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120° \, V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3° \, A]$
	$V_S = 95{,}757\angle 106.1° \, V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1° \, V}{4{,}511\angle 71.3° \, A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

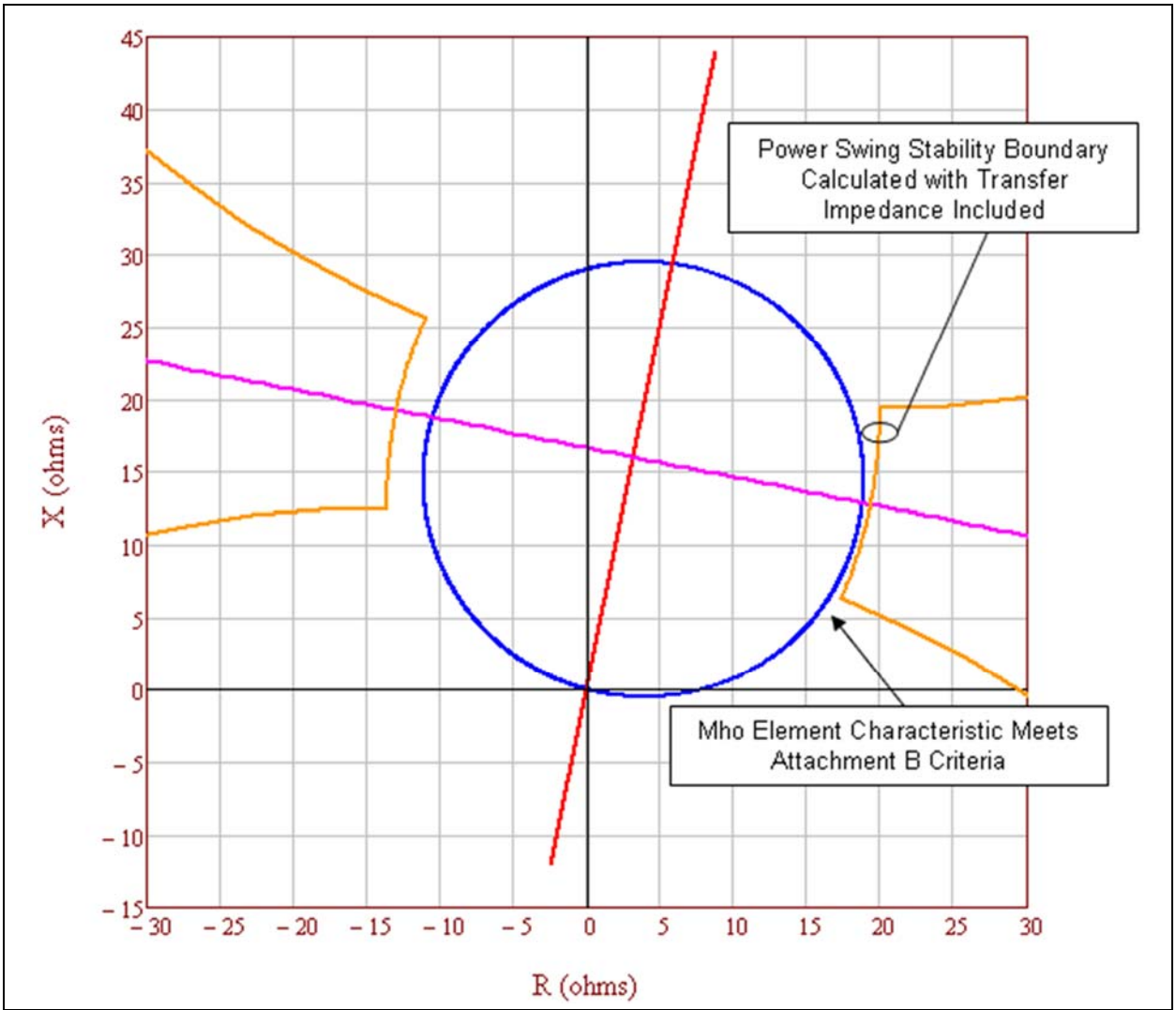


Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-1 – Attachment B, Criterion A because it is completely contained 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%

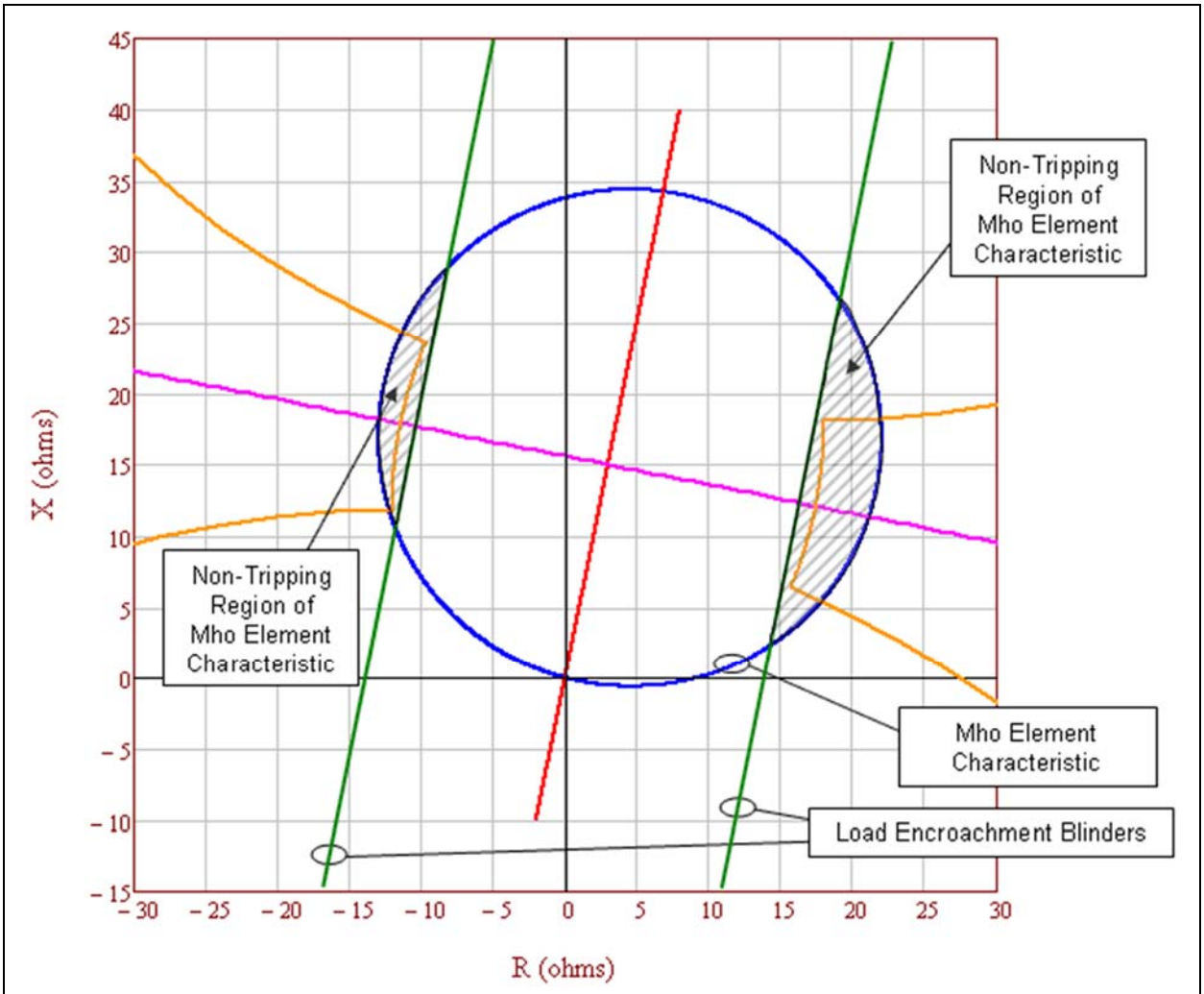


Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-1 – Attachment B, Criterion A.

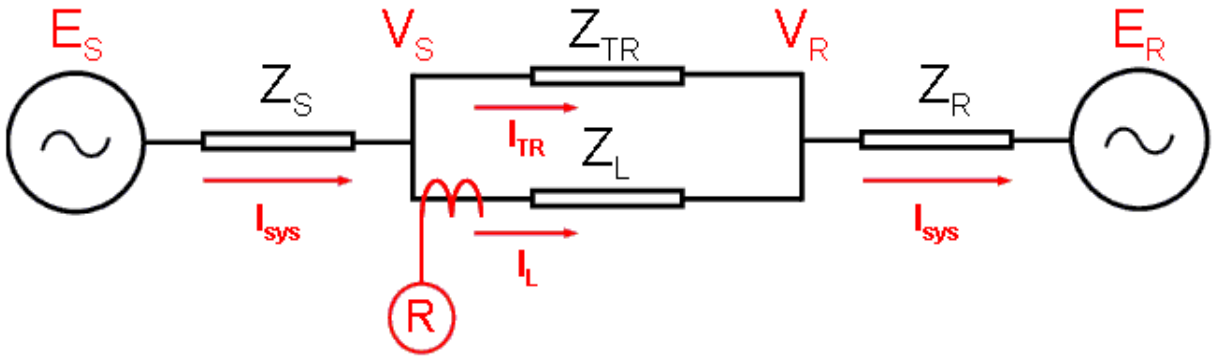


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

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)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

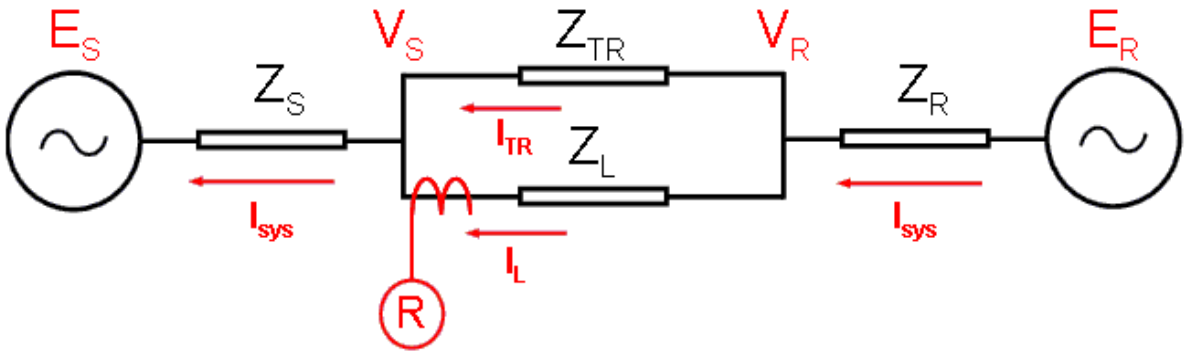


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

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.

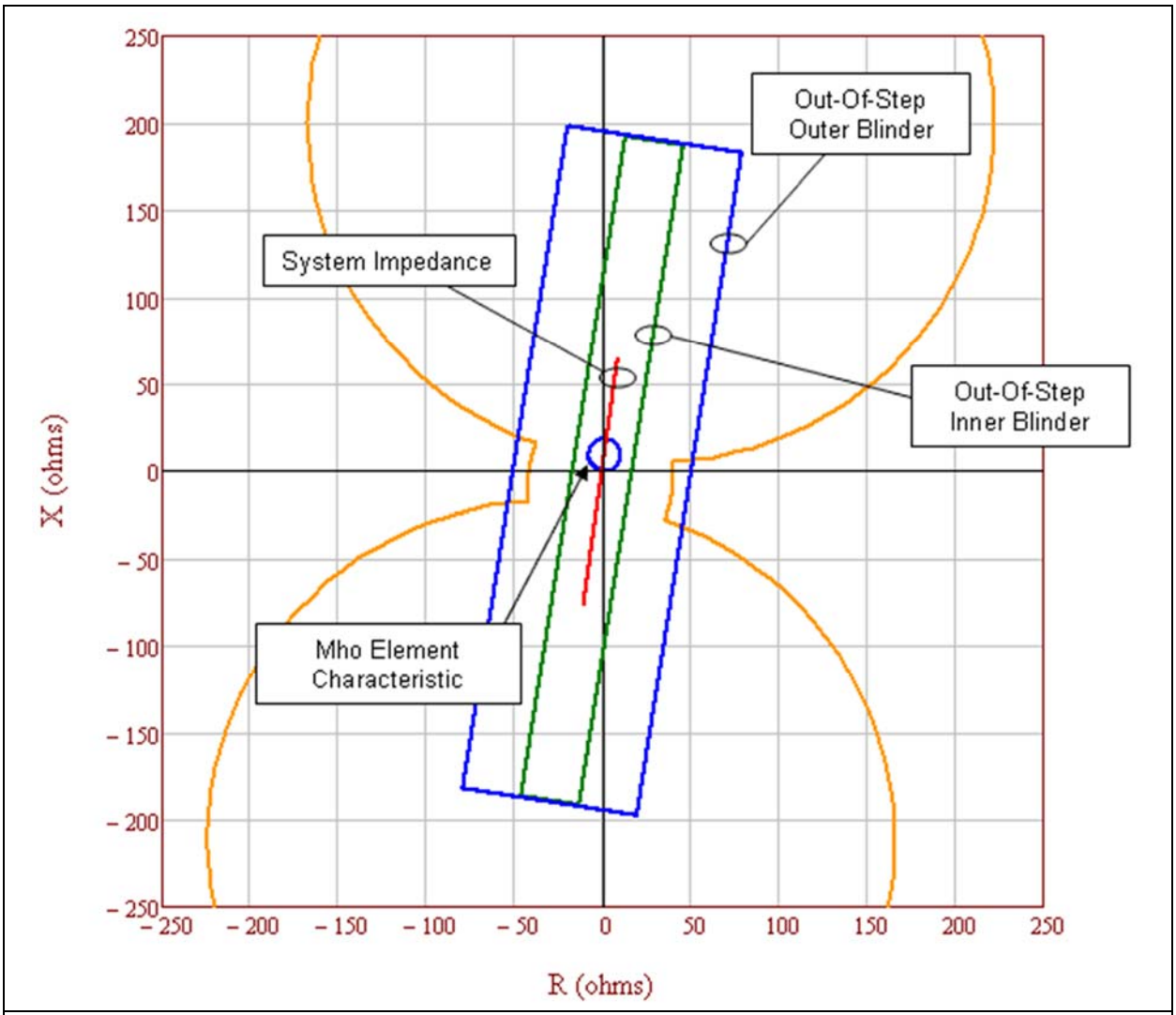


Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-1 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (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)	$r_b = \left\lvert \frac{N \times Z_{sys}}{N^2 - 1} \right\rvert$
	$r_b = \left\lvert \frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1} \right\rvert$
	$r_b = 69.987\ \Omega$

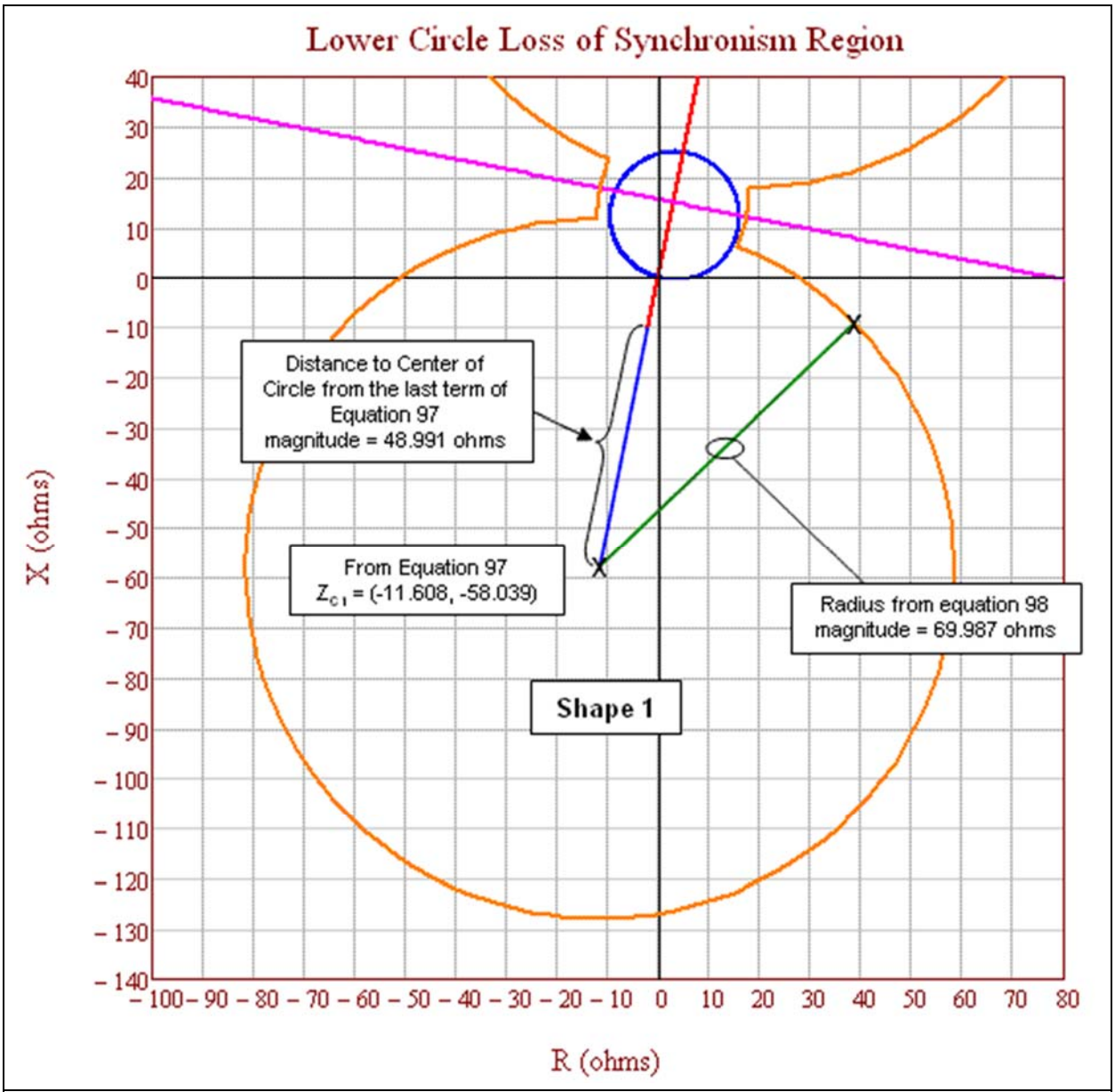


Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

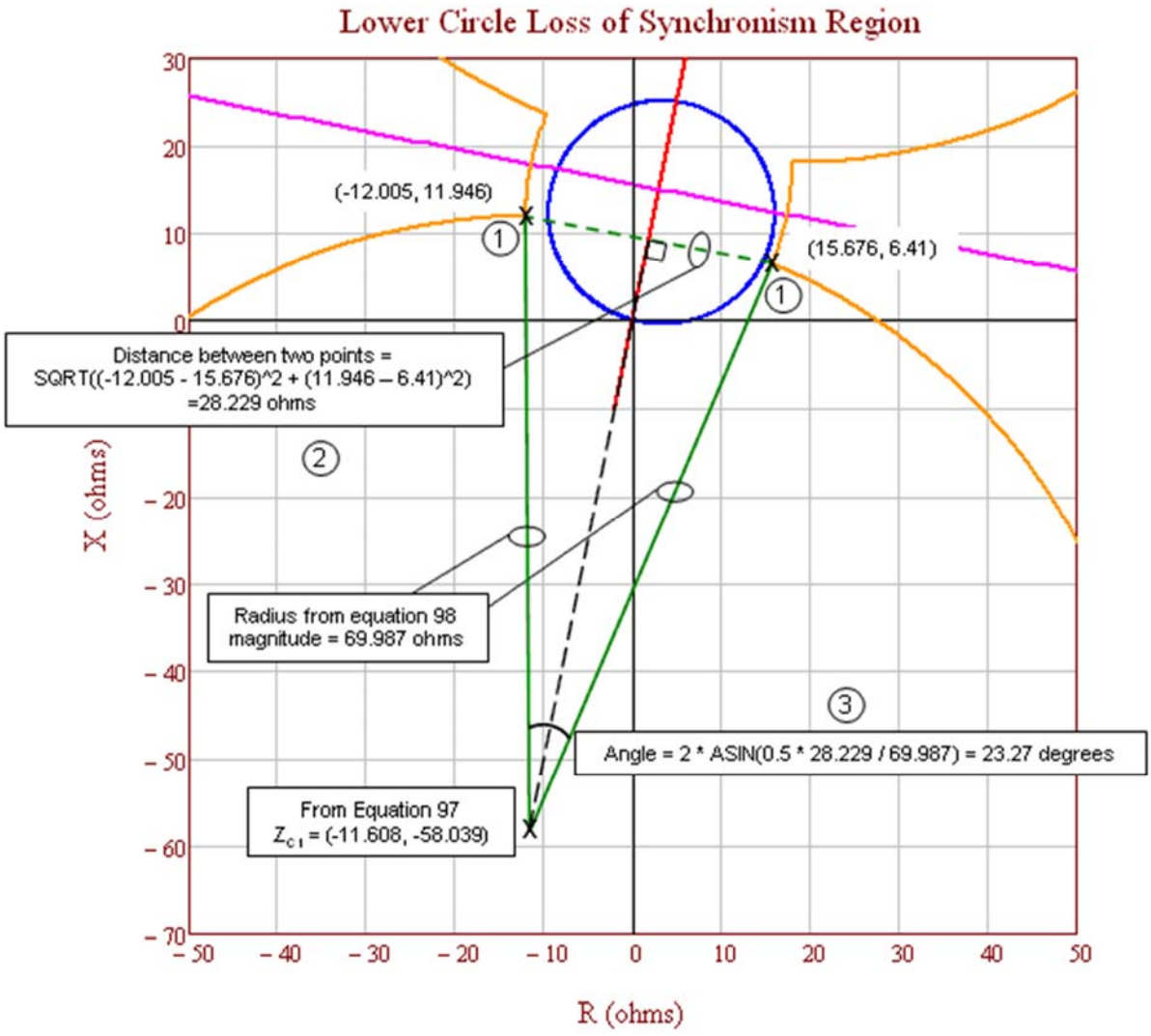


Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape 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.

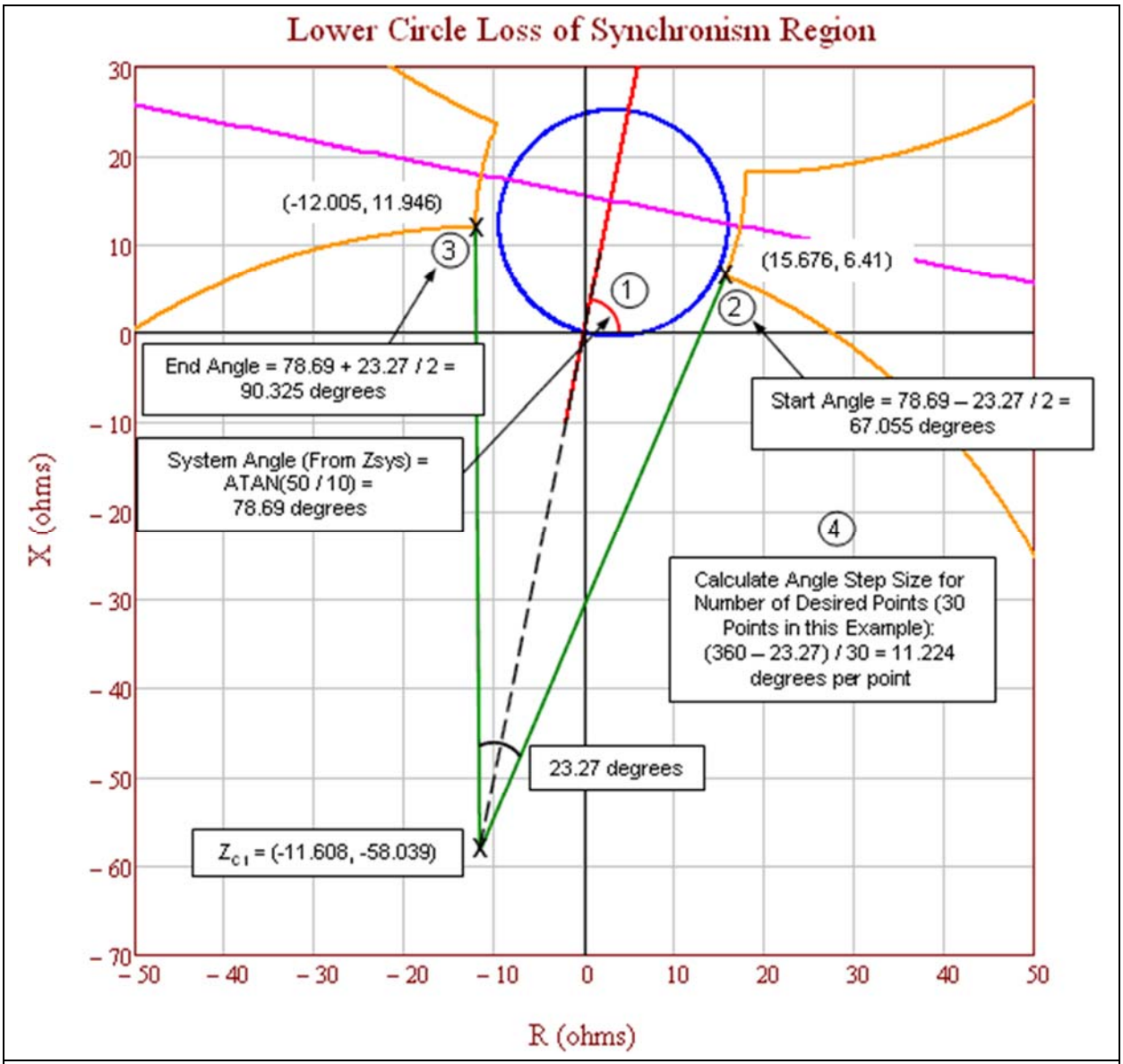


Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

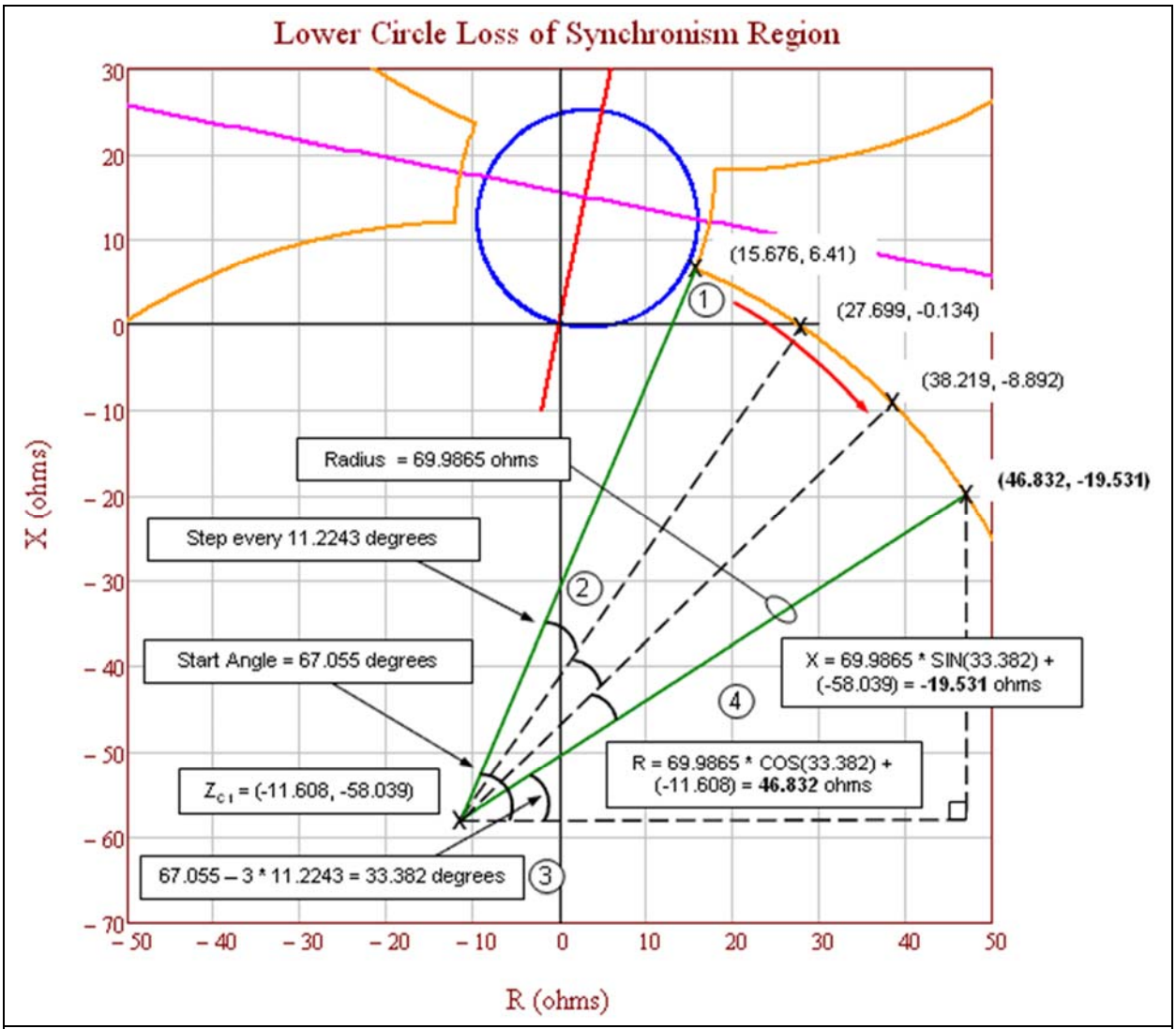


Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

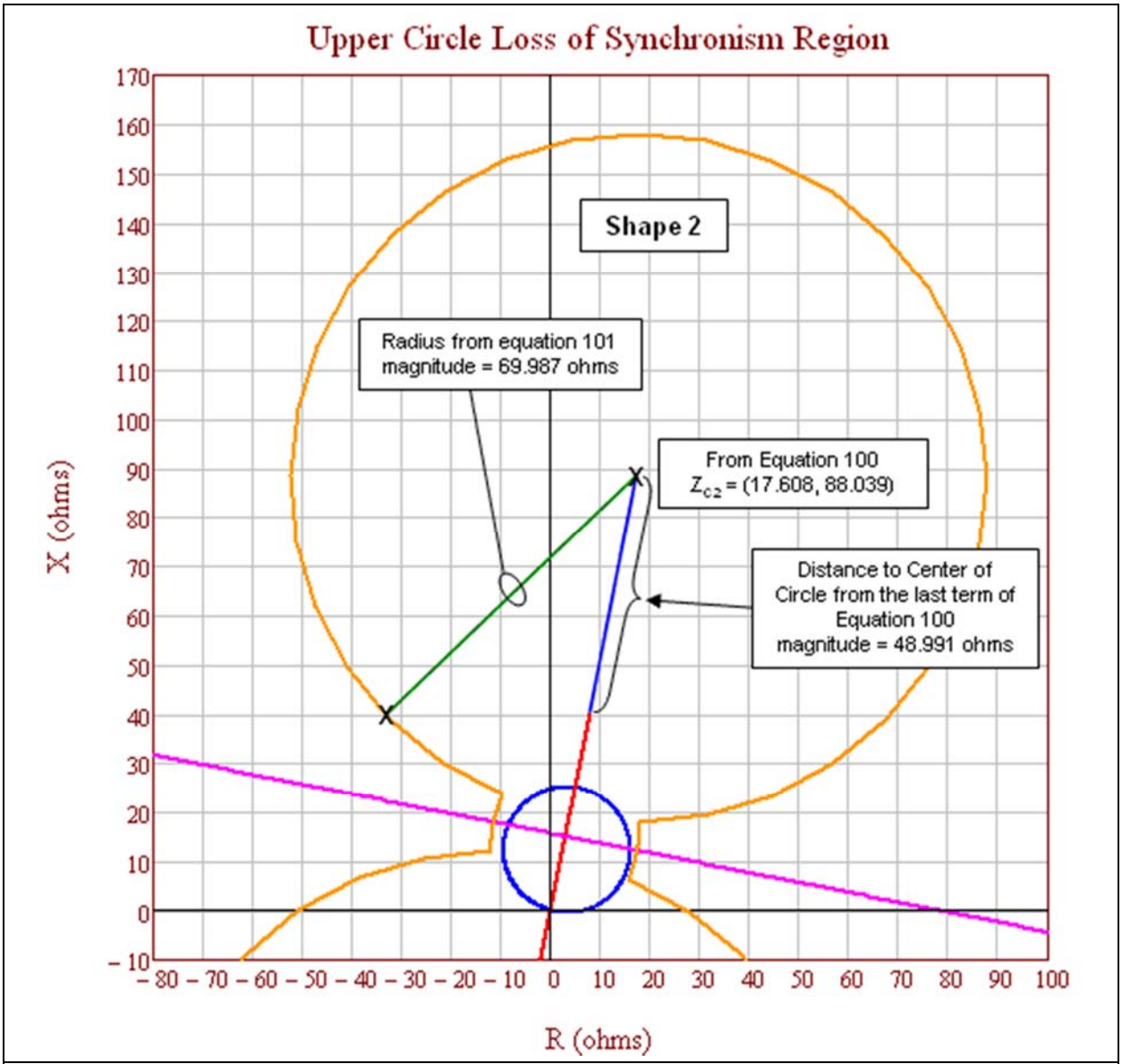


Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

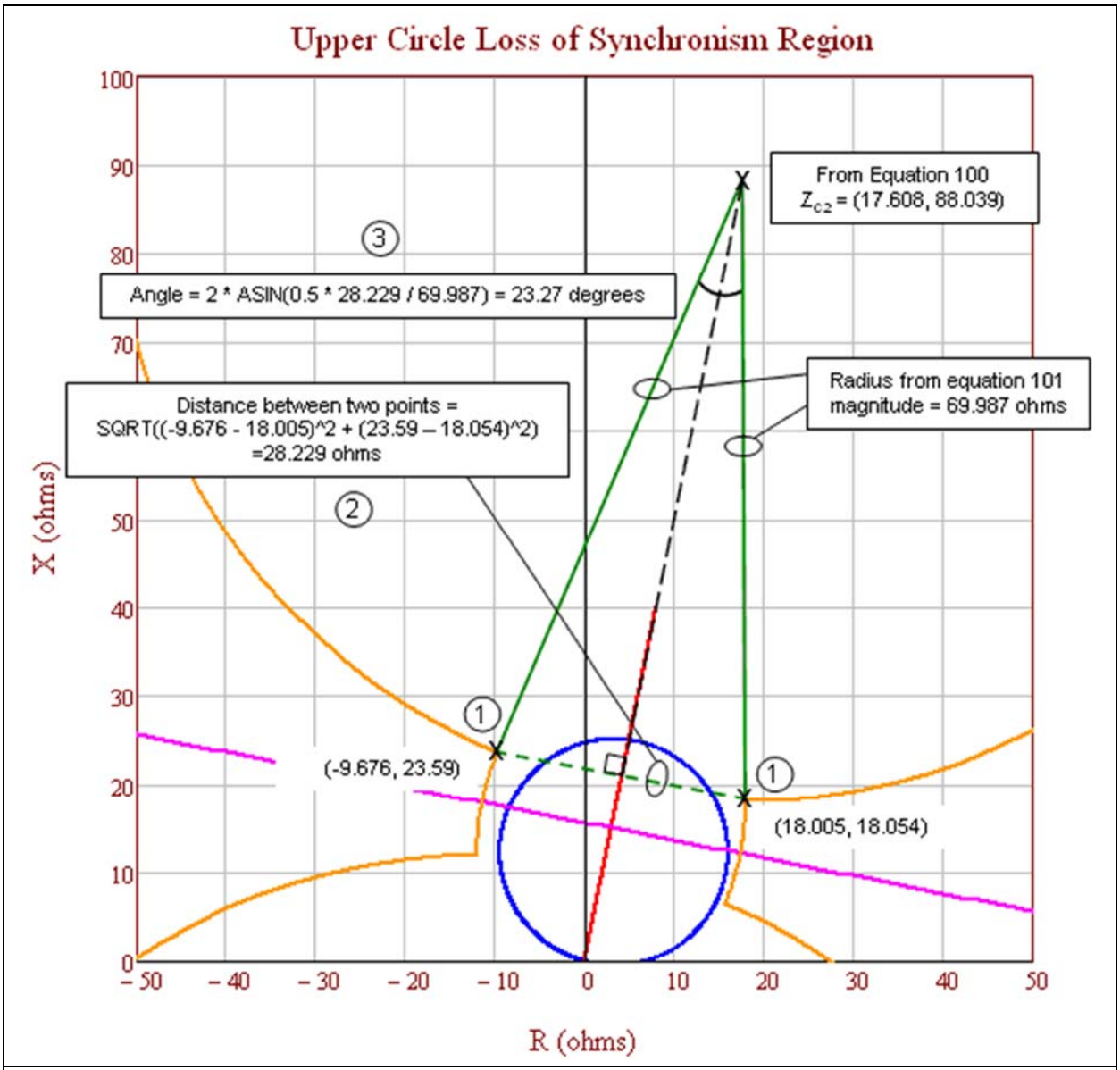


Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 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.

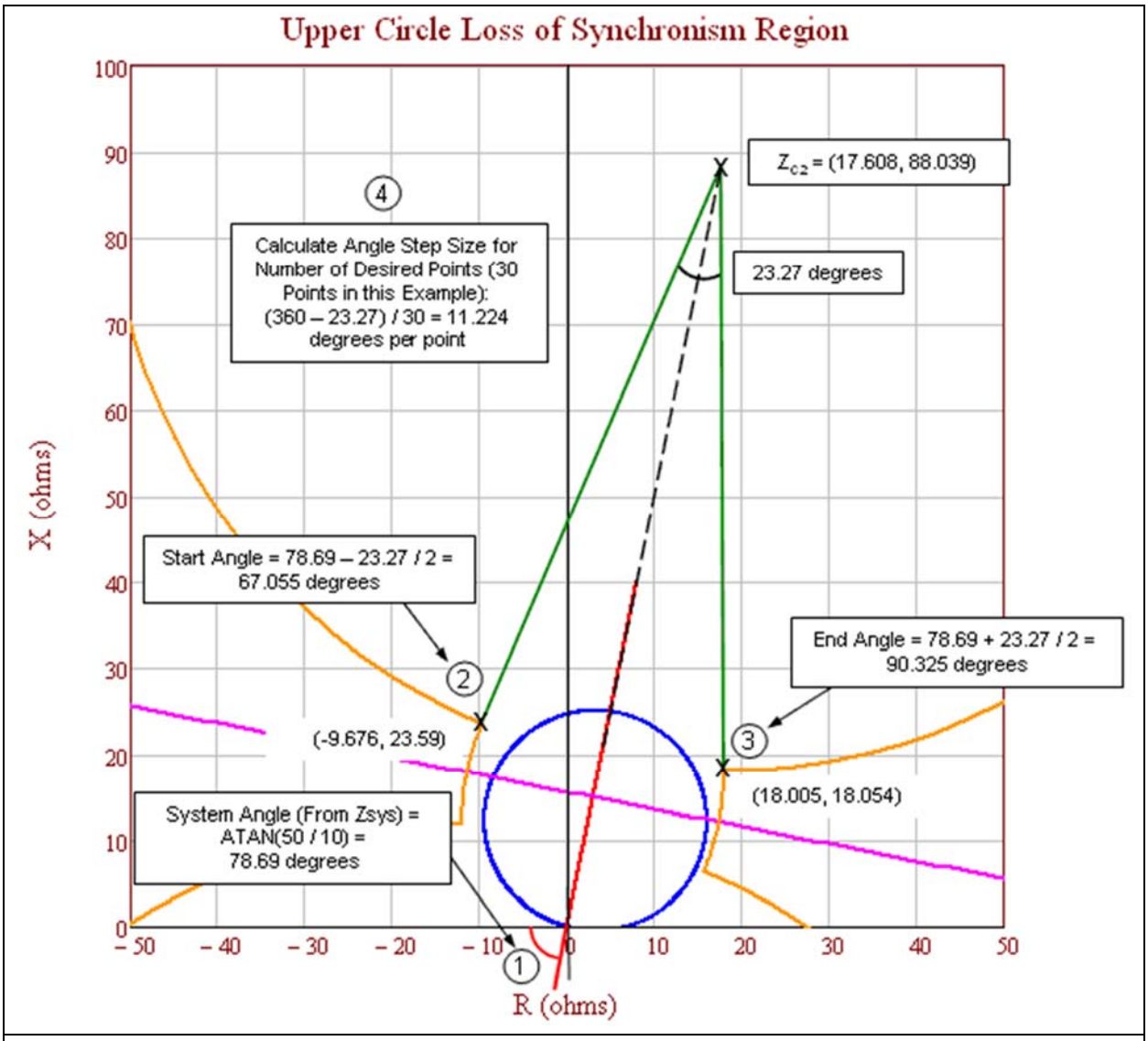


Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

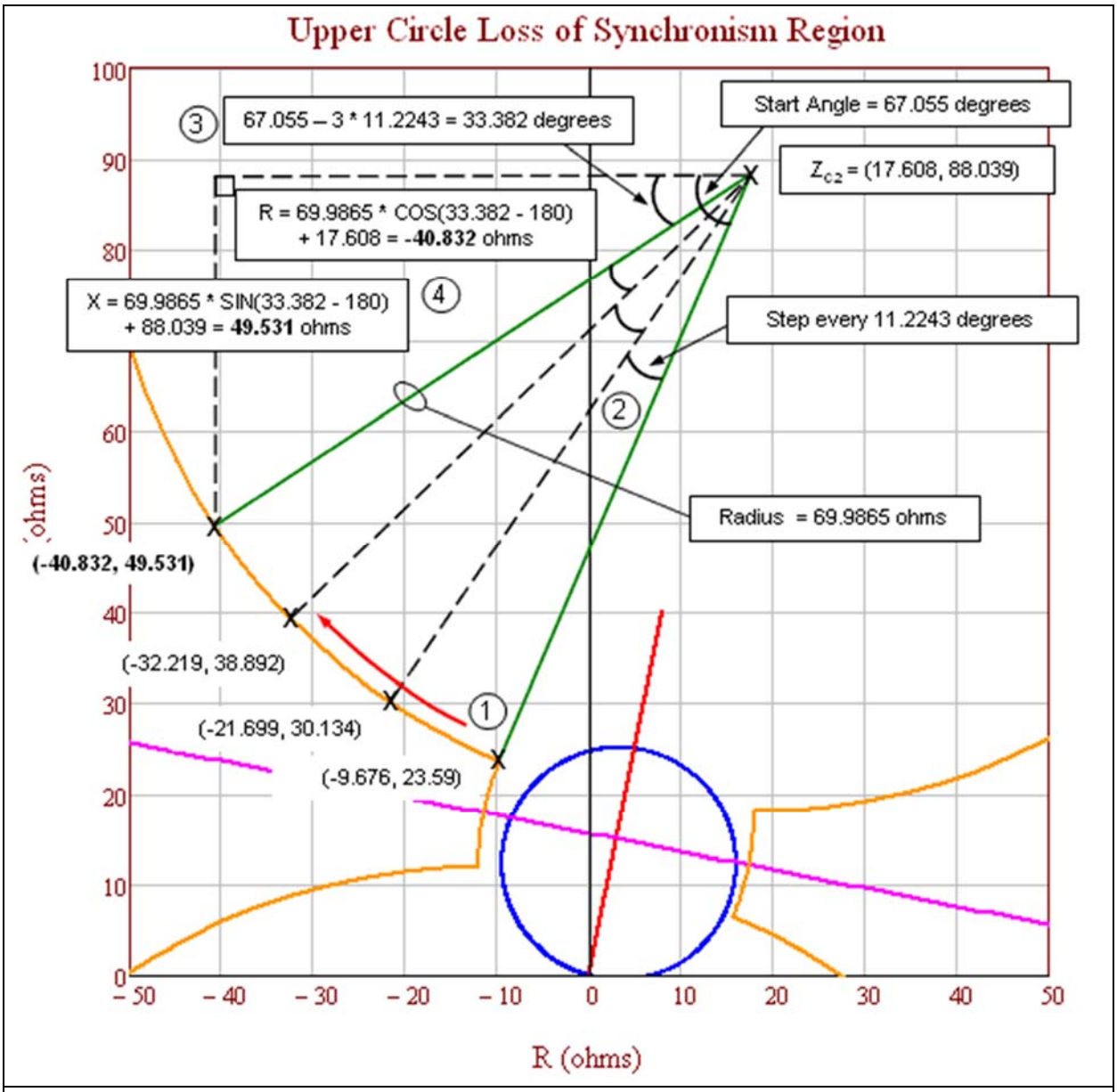


Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step 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).

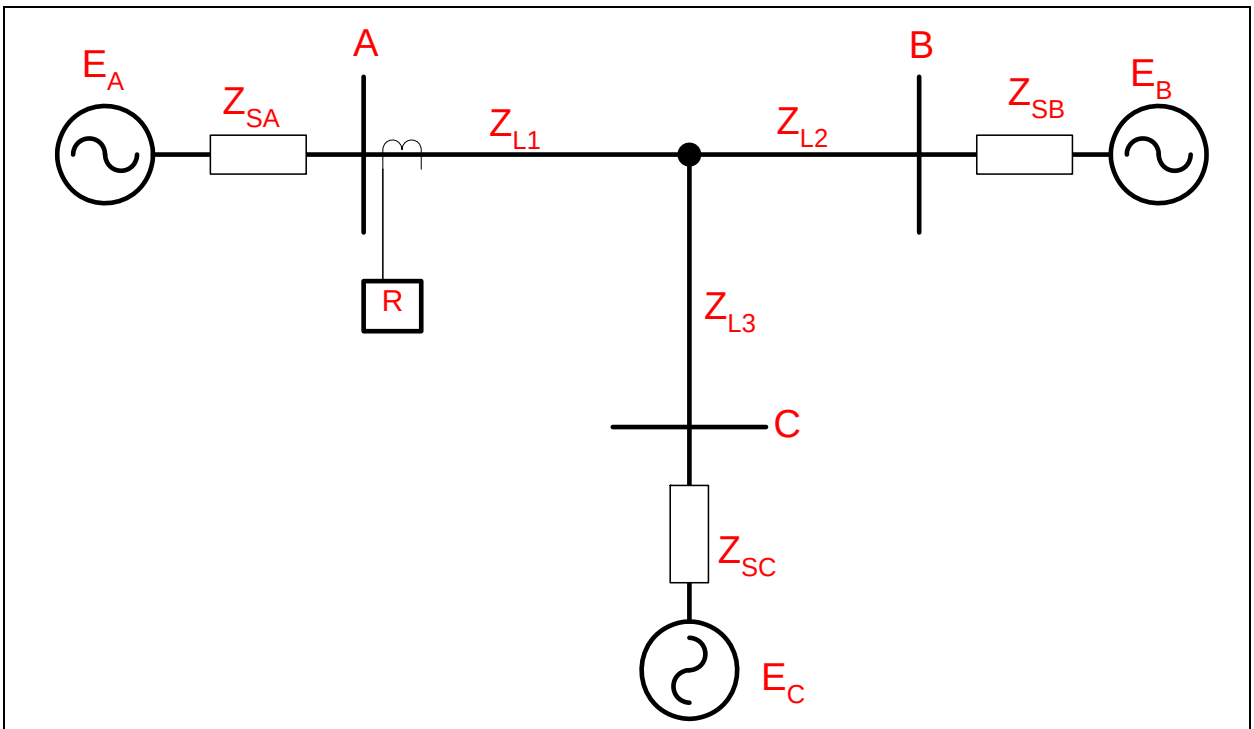


Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

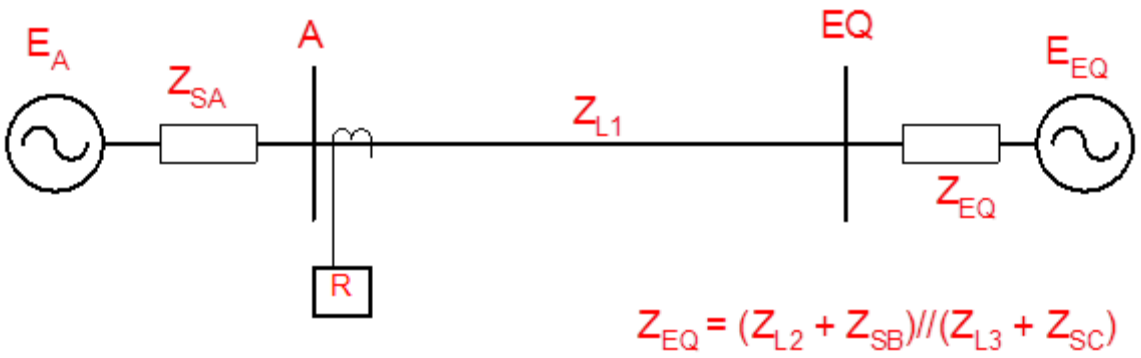


Figure 15k: Three-terminal line reduced to a two-terminal line.

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.

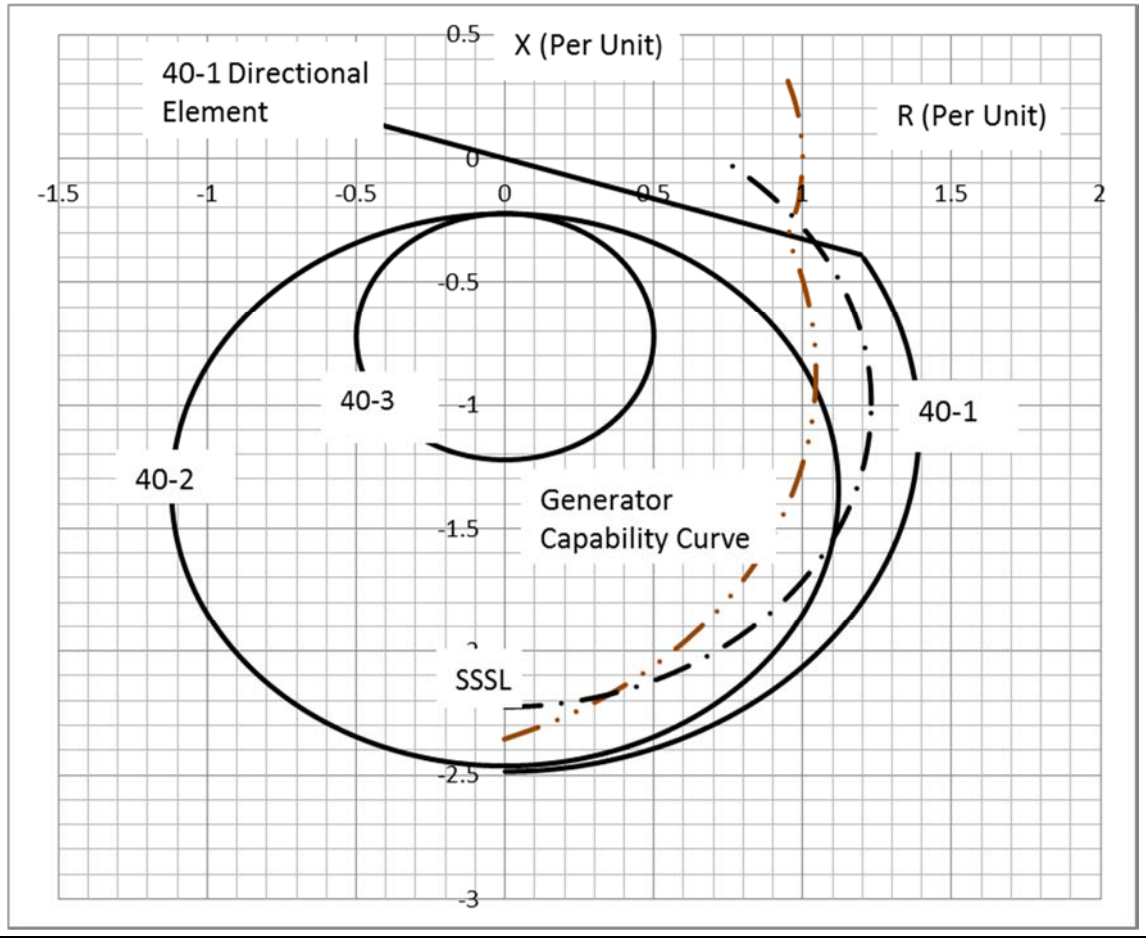


Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[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.

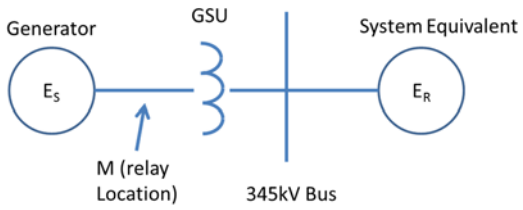


Figure 17: Simple one-line diagram of the system to be evaluated.

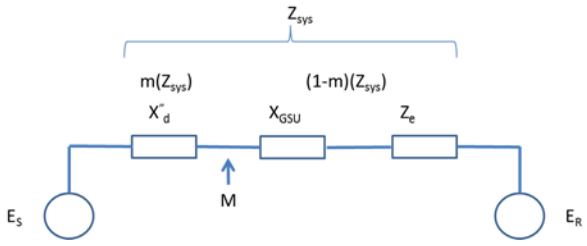


Figure 18: Simple system equivalent impedance diagram to be evaluated.[29]

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.

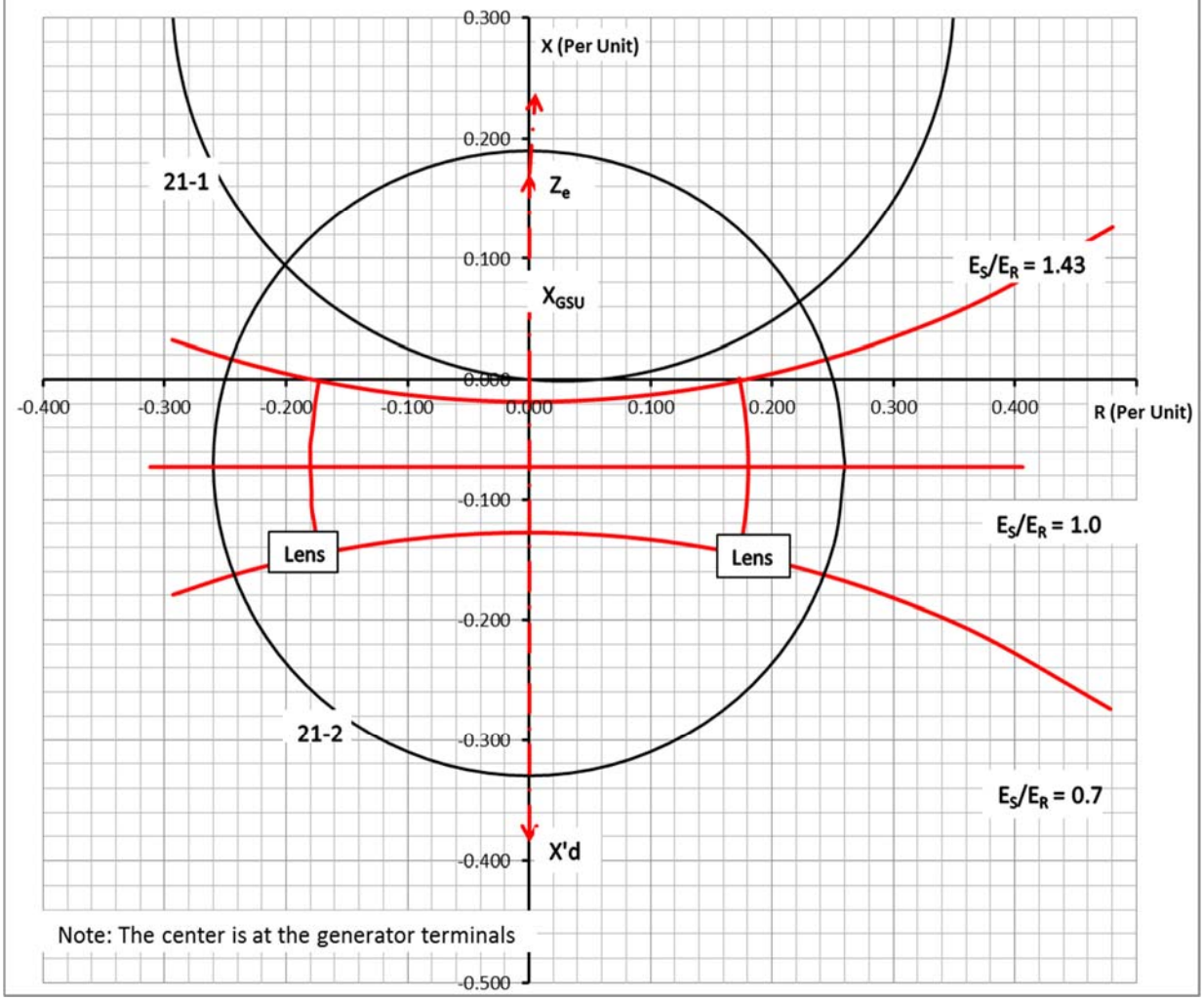


Figure 19: Swing impedance graph for impedance relays at a generating facility.

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.

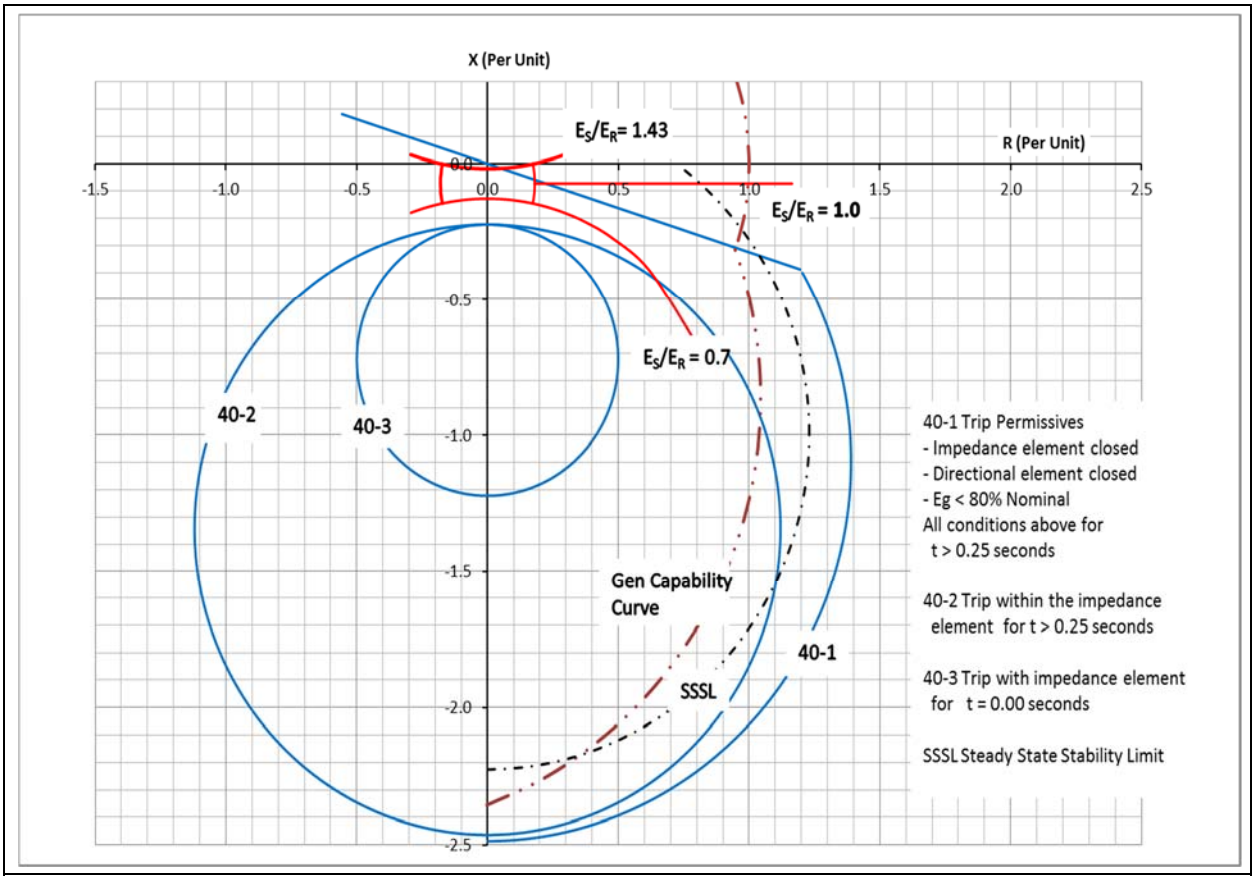


Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-1 – Attachment B, Criterion A.

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.

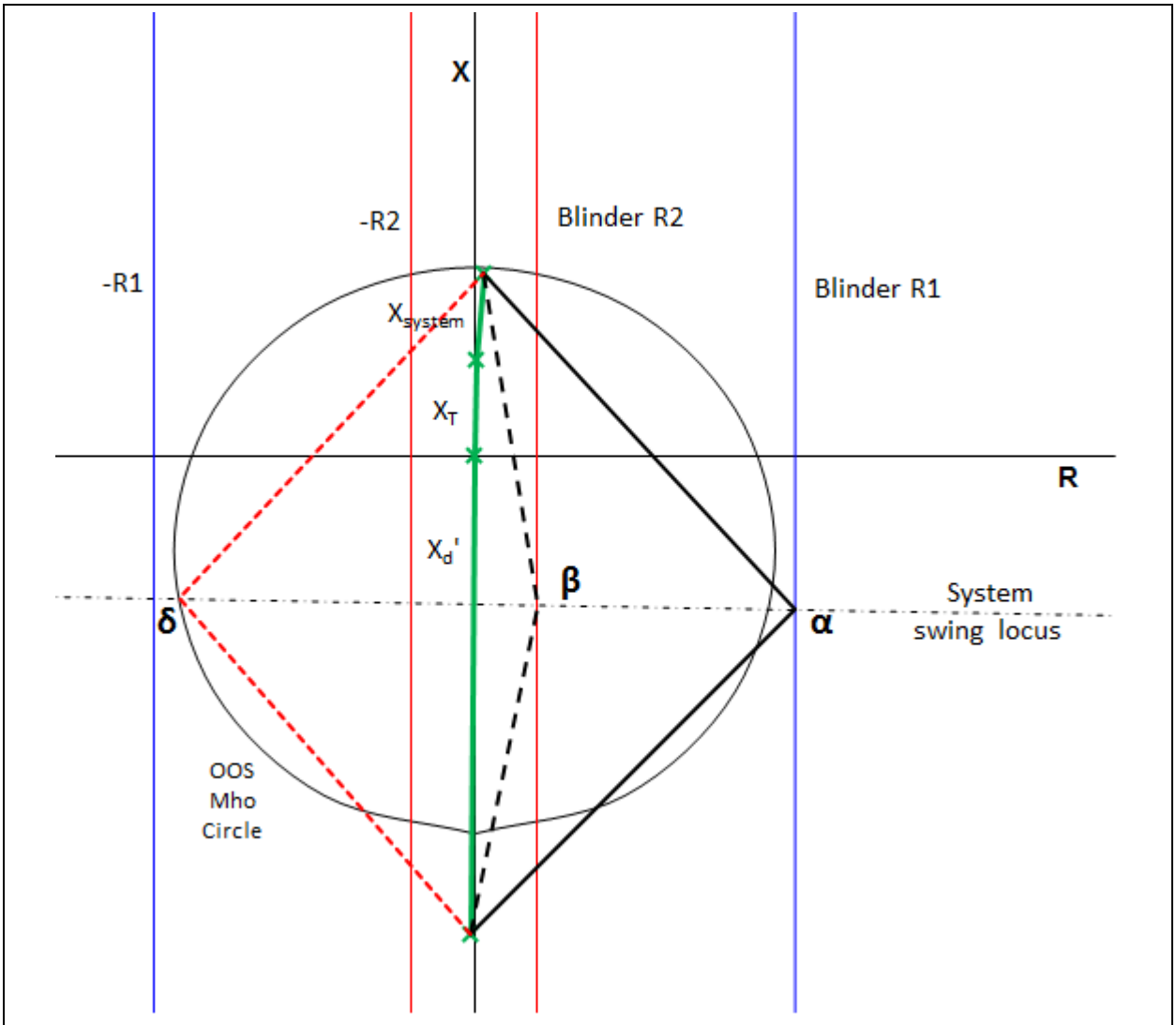


Figure 21: Double Blinder Scheme generic out of step characteristics.

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.

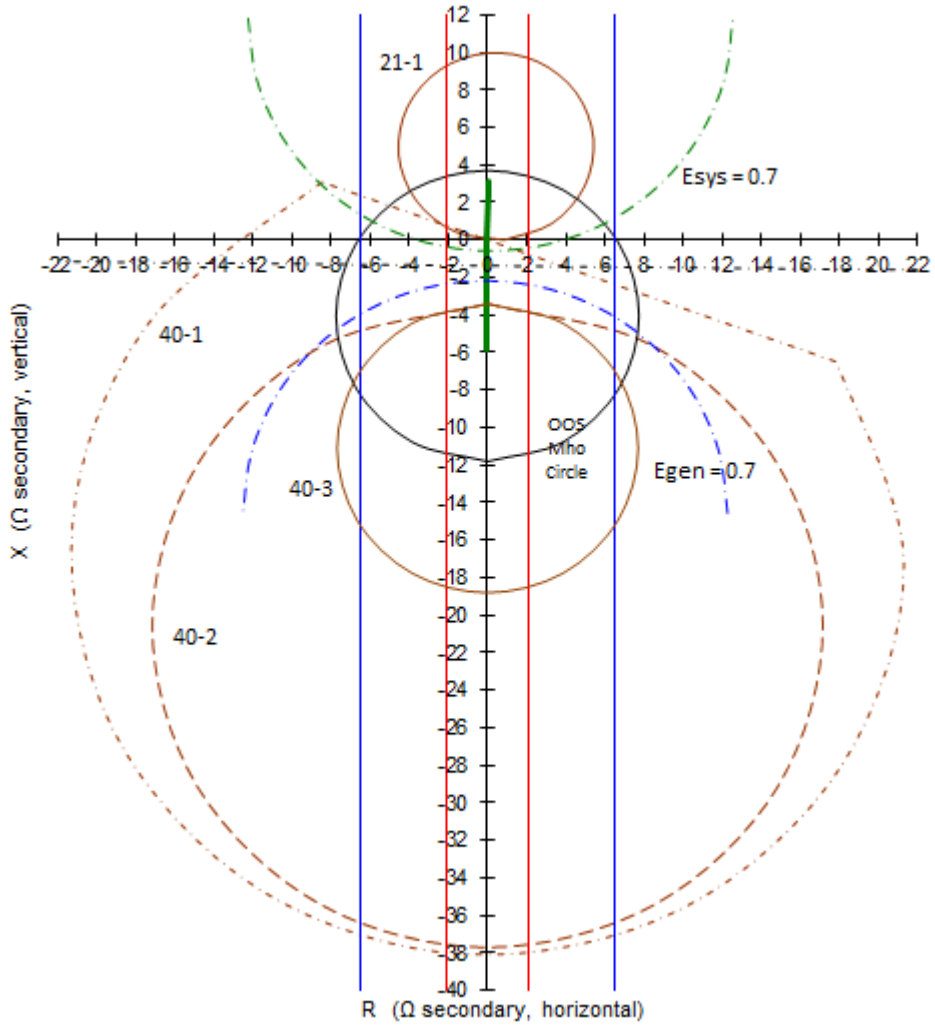


Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

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.

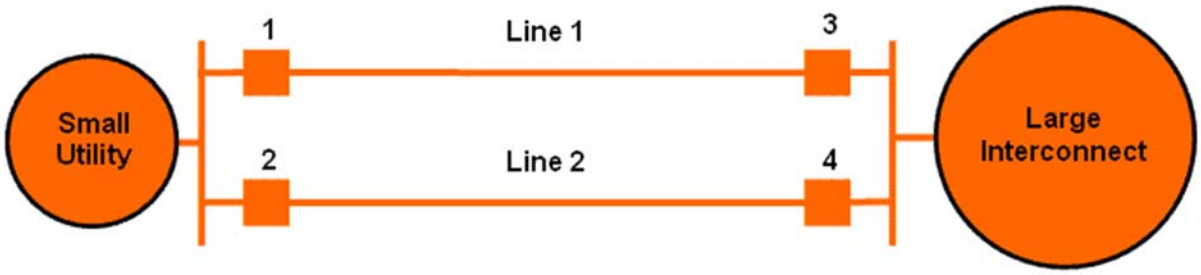


Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

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.

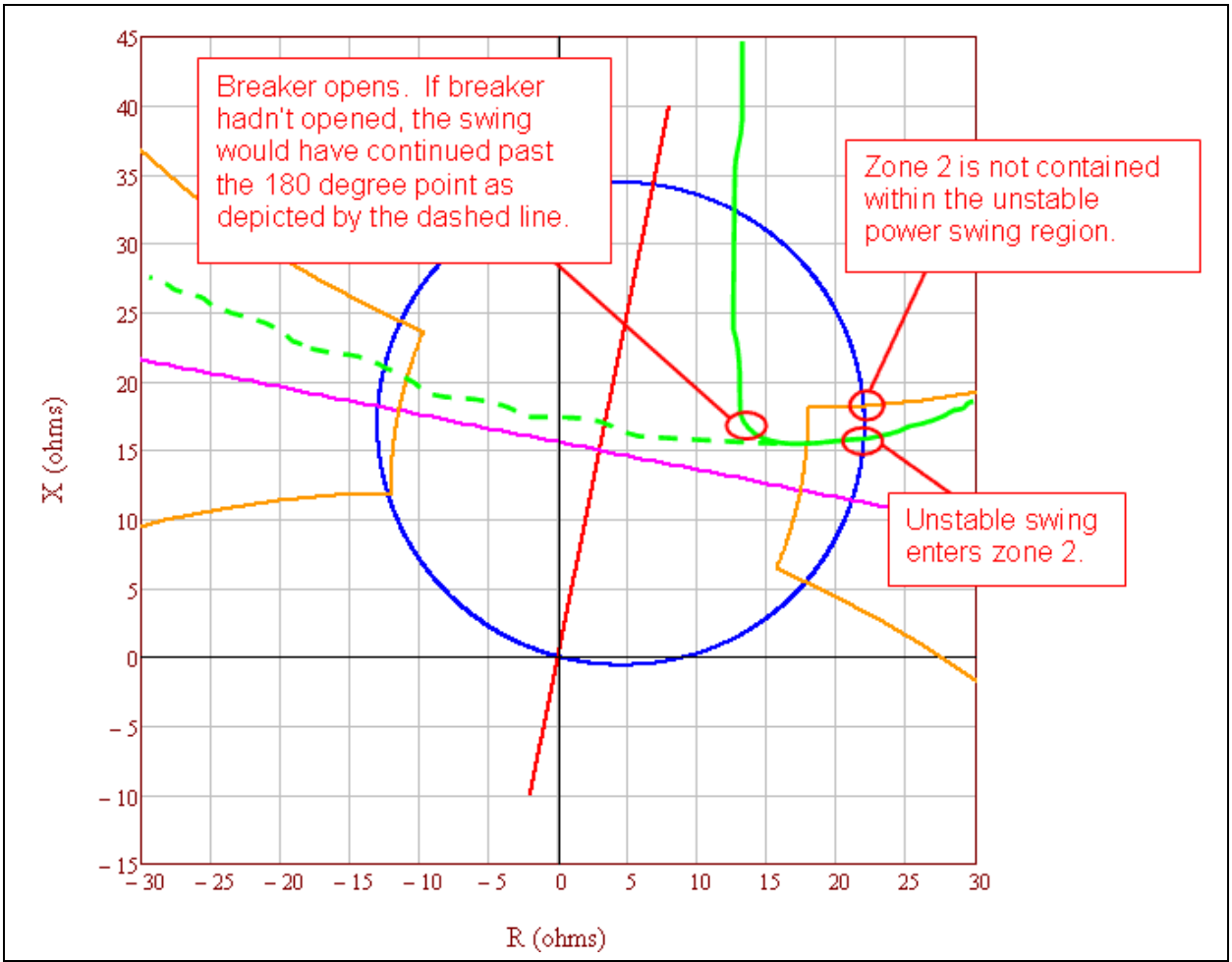


Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-1 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

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.

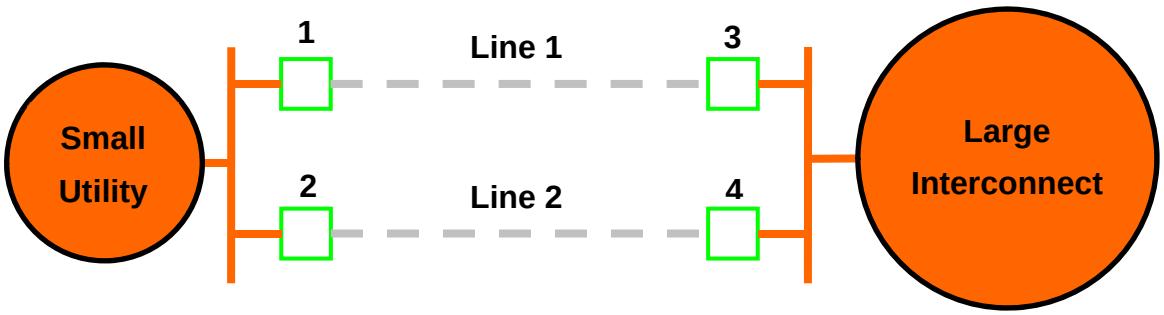


Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

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.

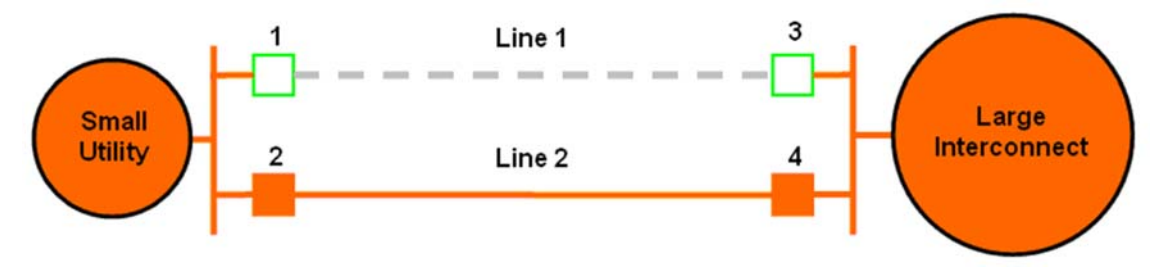


Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

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.

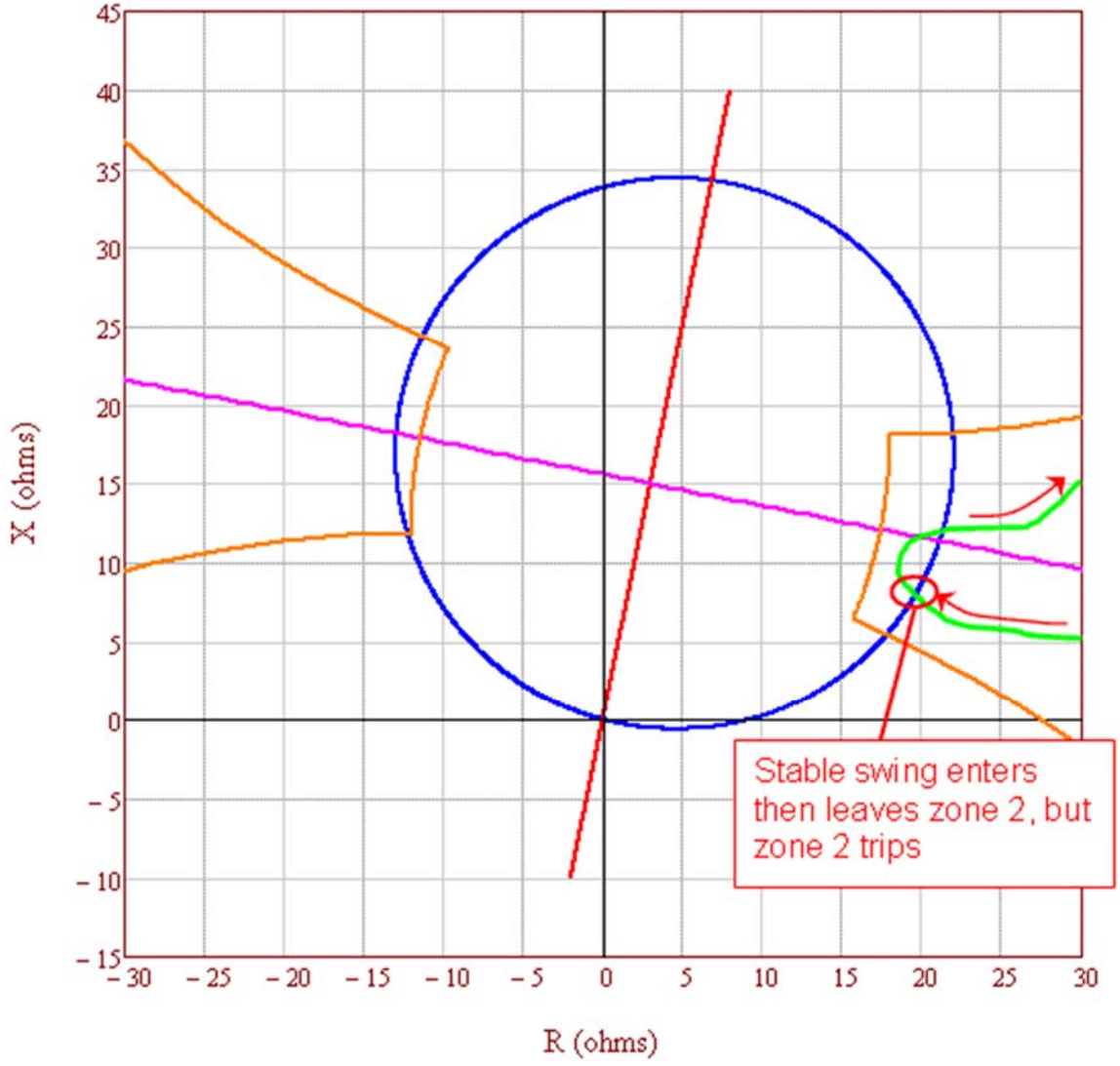


Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-1 – Attachment B criteria following the previous unstable power swing event.

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.

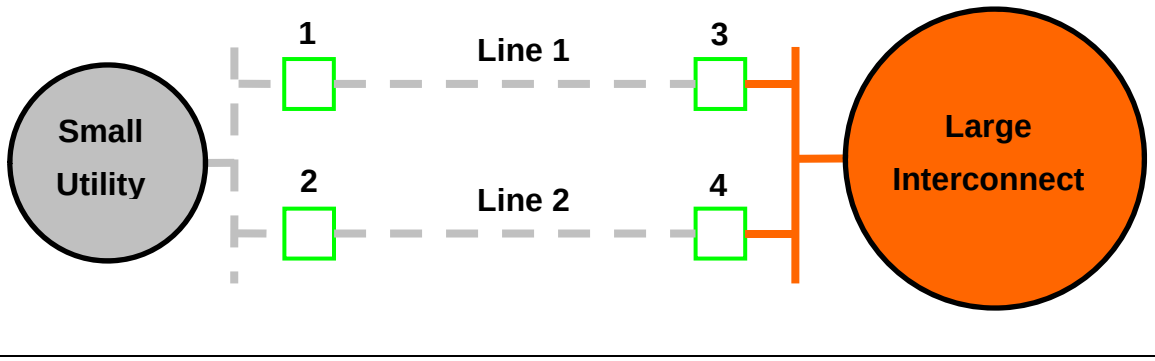


Figure 28: Possible blackout of the small utility.

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).

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 additional ballot	August 2018 – October 2018
10-day final ballot	October 2018
NERC Board adoption	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 the owner-provided Facility Ratings used in operations per the Reliability Coordinator's SOL Methodology. The process may allow the use of less limiting Facility Ratings 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 used in operations per the Reliability Coordinator's SOL Methodology. *[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 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 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 used in operations per the Reliability Coordinator's SOL Methodology. *[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 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, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);

4.2 The associated stability criteria used as part of determining the instability;

4.3 The associated Contingency(ies) and any Facilities critical to the instability, Cascading or uncontrolled separation;

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 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

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 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 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	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 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	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 provide its technical rationale.	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 Reliability Coordinator's SOL Methodology.

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

				The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, 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
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

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.

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[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.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	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 additional ballot	June 3 – July 18, 2019

Anticipated Actions	Date
10-day final ballot	July 24 – August 2, 2019
NERC Board	August 15, 2019

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization

2. **Number:** CIP-002-~~5.1a~~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 ~~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-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:** See Implementation Plan for CIP-002-6

5.1. 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:

For a planned change resulting in a new BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the new BES Cyber System is capable of impacting the BES. By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new categorization to the new BES Cyber System.

[1] Planned changes 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. 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 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 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) a Responsible Entity is notified (internally or externally) that a generation Facility has been designated per CIP-002, Attachment 1, Criterion 2.3; (2) a Responsible Entity is notified (internally or externally) that a generation or Transmission Facility has been identified per CIP-002, Attachment 1, Criterion 2.6; (3) a generating resource that is connected at less than 100kV is designated per CIP-002, Attachment 1, Criterion 3.4; or (4) 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 2.10.

For a planned change resulting in a change in categorization for an existing BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets the new impact criteria in Attachment 1, regardless of when the Responsible Entity performs its review of identifications under Requirement R2, Part 2.1. By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new categorization to the existing BES Cyber System.

For an unplanned change resulting in a new BES Cyber System or a higher categorization for an existing BES Cyber System, the new or changed categorization to the BES Cyber System shall become effective 24 calendar months from the date of notification or detection of the unplanned change. By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new or changed categorization to the new or existing BES Cyber System.

For unplanned changes resulting in a higher categorization for an existing BES Cyber System, the prior lower categorization shall remain effective until 24 calendar months from the date of notification or detection of the unplanned change.

For requirements that contain periodic obligations, initial performance of those new obligations following a planned change shall occur within the first period following the date the new BES Cyber System could adversely impact the BES or the date the existing BES Cyber System meets the new impact criteria in Attachment 1. Initial performance of those new obligations following an unplanned change shall occur within the first period after 24 calendar months from the date of notification or detection of the unplanned change.

~~1. **24 Months Minimum –** CIP-002-5.1a 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.~~

~~In those jurisdictions where no regulatory approval is required CIP-002-5.1a 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:**

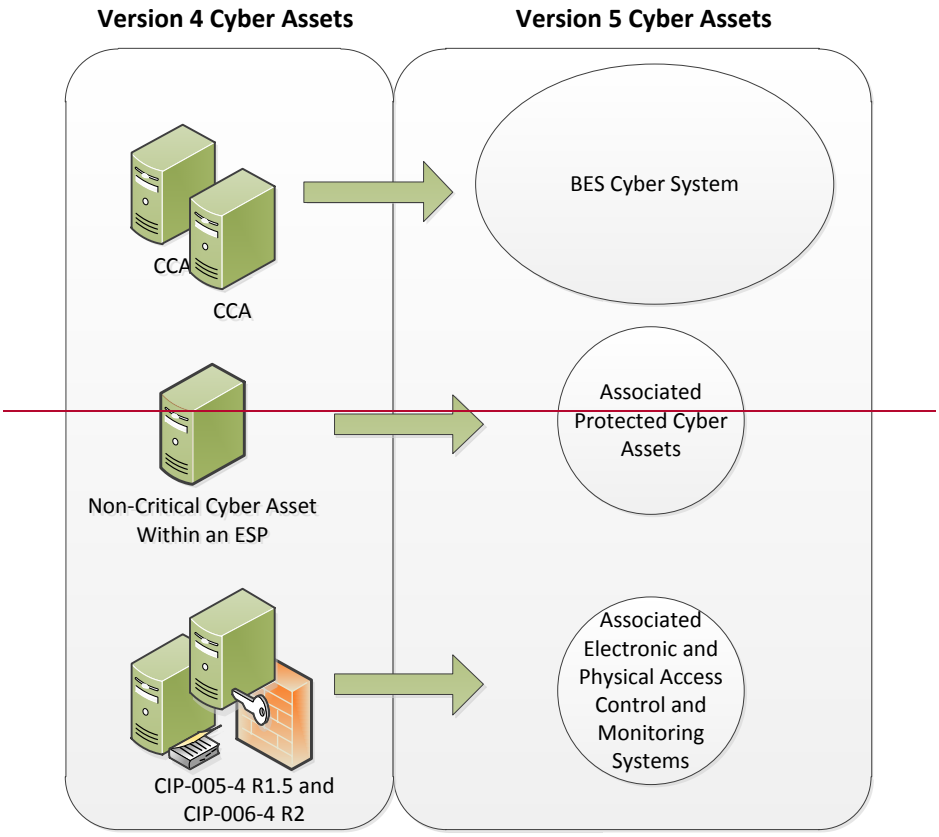
This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation 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."

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 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.

BES Cyber Systems

~~One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team's review of the NIST Risk Management Framework and the use of an analogous term "information system" as the target for categorizing and applying security controls.~~



~~In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the "BES Cyber System" term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.~~

~~Another reason for using the~~The term "BES Cyber System" ~~is to~~ provides a convenient level at which a Responsible Entity can organize its~~their~~ documented implementation of the requirements and ~~its examples of~~ compliance evidence. Responsible Entities can use a ~~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 characteristics 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 ~~Version 5~~ 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 more precisely better defined time horizon than "Real-time," 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 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 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 2.11Section 1 or Section 2, and listed in Section 3 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 Version 5 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.** ~~Special Protection Systems~~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-~~5.1a~~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-~~5.1a~~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-~~5.1a~~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-~~5.1a~~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

~~None.~~

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

~~CIP-002-5.1a -~~

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.

Version	Date	Action	Change Tracking
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata
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 ~~(H)~~

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 ~~(M)~~

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 its Reliability Coordinator, Planning Coordinator, or Transmission Planner 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 ~~Special Protection System (SPS),~~ Remedial Action Scheme (RAS~~),~~,) or automated switching System that operates BES Elements, that~~,~~ if destroyed, degraded, misused or otherwise rendered unavailable, would 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 ~~(H)~~ 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.

~~**2.12** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.~~

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 ~~(H)~~ 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 ~~(L)~~

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. ~~Special Protection Systems~~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-~~5.1a~~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-~~5.1a~~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-~~5.1a~~6

CIP-002-~~5.1a~~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-~~5.1a.~~ 6. The concept includes a number of named BES reliability operating services. ~~-These named services include:~~

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)
- ~~Special Protection Systems or~~ 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 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 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 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 SOL's & 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 Situation 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

The Inter-Entity coordination and 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 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, Section 1 or Section 2, and listed in Section 3 ~~1.1 – 1.4 and Criteria 2.1 – 2.11~~ 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 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-~~5.1a~~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 ~~(H)~~

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, B~~A~~As, 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~~BAs with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating ~~(M)~~

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, whose purpose is "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 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 Bas 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 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.

  IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for ~~Special Protection Systems and~~ Remedial Action Schemes as medium impact. ~~Special Protection Systems and~~ Remedial Action Schemes 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.

- 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 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 500kV 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 Attachment 1 of NERC's ~~document~~ "Integrated Risk Assessment Approach – Refinement to Severity Risk Index" document, ~~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 include BES Cyber Systems for those Transmission Facilities that have been identified 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 Special Protection Systems (SPS),~~ Remedial Action Schemes (RAS~~),~~) or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs 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. ~~-~~The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. ~~-~~In the drafting of this criterion, the drafting team sought to include 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. ~~-~~It should be noted that those qualifying systems which require a human operator to arm the system, 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.

  This particular threshold (300 MW) was provided in CIP, Version 1.~~-~~ The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System 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, but are offered as components of an ancillary services market 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 ~~as~~ medium impact ~~those~~ BES Cyber Systems ~~used by and at~~ associated with Control Centers and backup Control Centers, including associated data centers ~~performing the functional obligations of a~~, that monitor and control BES Transmission ~~Operator~~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 would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

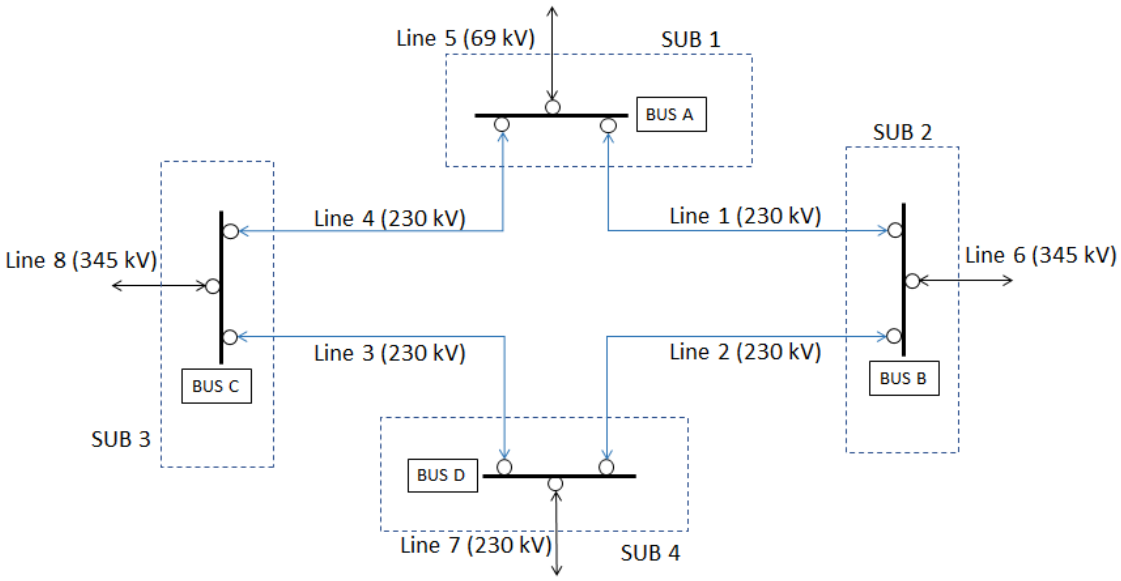
  The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at an appropriate 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

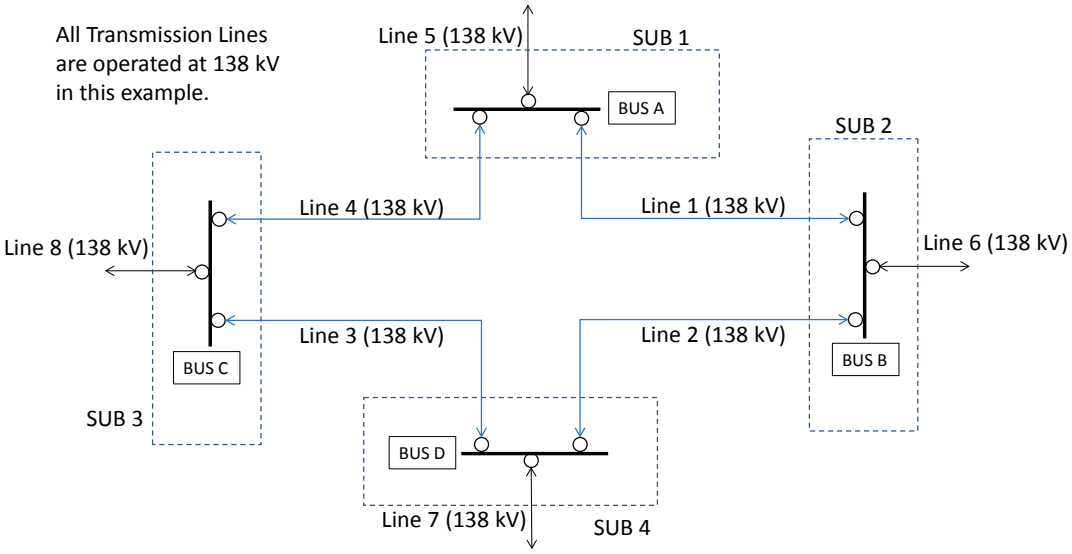
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in 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 ~~high impact.~~ 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 ~~(L)~~

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.

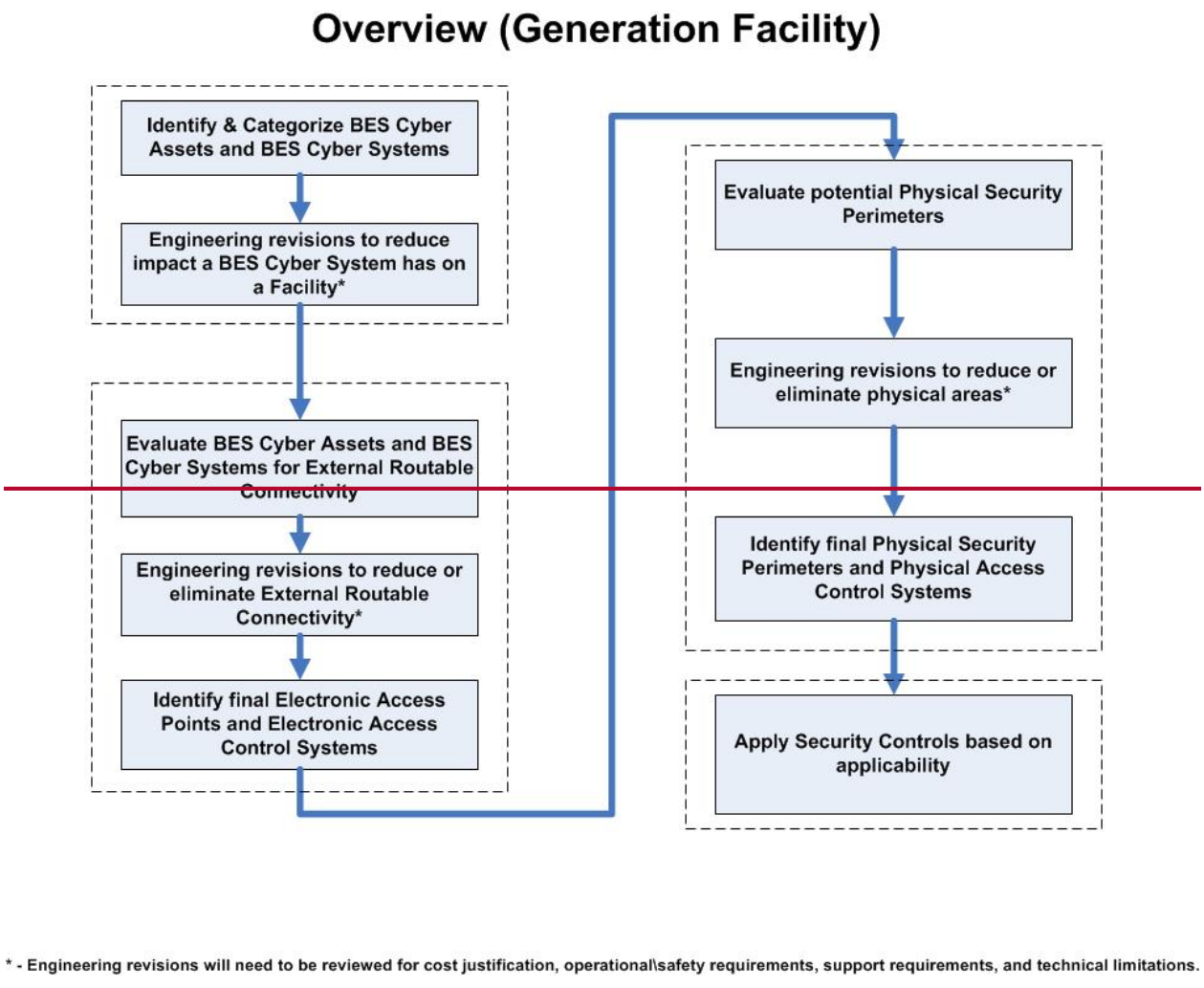
Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific 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.

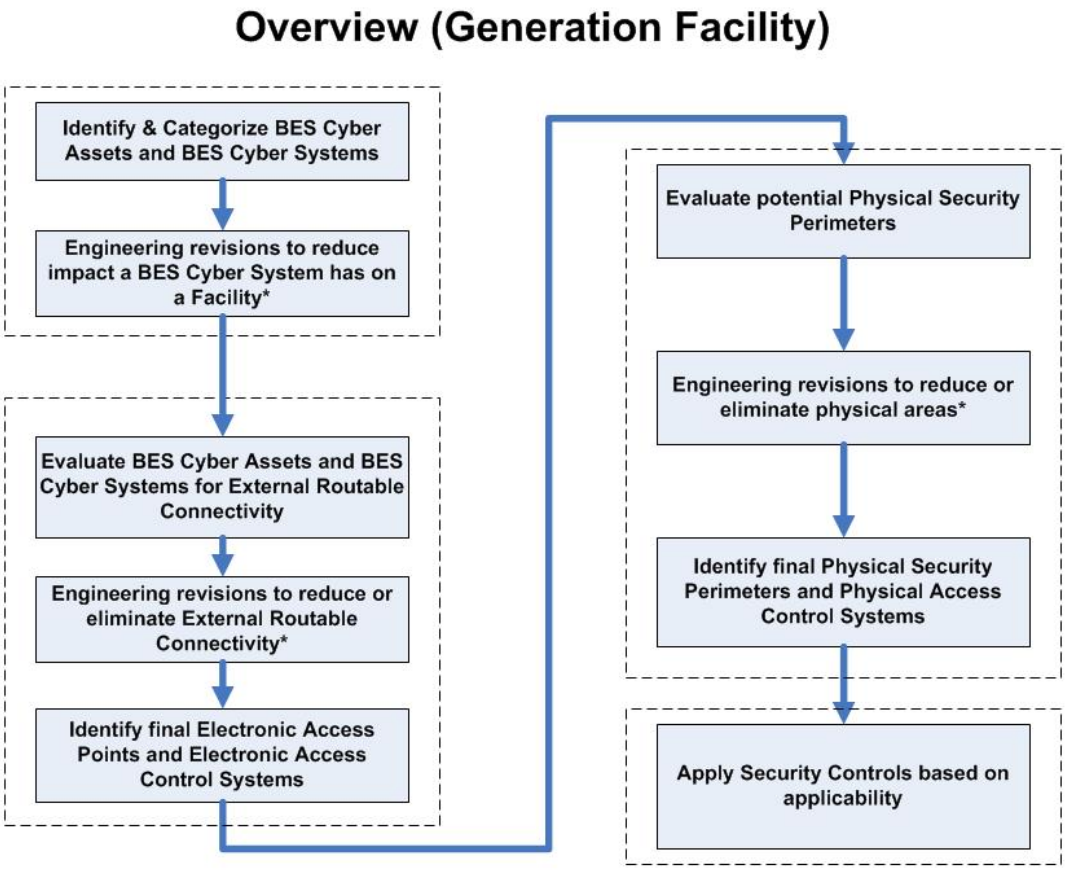
  Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator 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.



* - 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.

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 of 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
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.~~	

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. ~~Special Protection Systems~~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 ~~(M)~~

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.

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.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	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 additional ballot	June 3 – July 18, 2019

Anticipated Actions	Date
10-day final ballot	July 24 – August 2, 2019
NERC Board	August 15, 2019

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:** See Implementation Plan for CIP-002-6

5.1. 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:

For a planned change resulting in a new BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the new BES Cyber System is capable of impacting the BES. By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new categorization to the new BES Cyber System.

For a planned change resulting in a change in categorization for an existing BES Cyber System, the categorization of the BES Cyber System shall become effective upon the date the BES Cyber System meets the new impact criteria in Attachment 1, regardless of when the Responsible Entity performs its review of identifications under Requirement R2, Part 2.1. By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new categorization to the existing BES Cyber System.

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[1] Planned changes 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. 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 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 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) a Responsible Entity is notified (internally or externally) that a generation Facility has been designated per CIP-002, Attachment 1, Criterion 2.3; (2) a Responsible Entity is notified (internally or externally) that a generation or Transmission Facility has been identified per CIP-002, Attachment 1, Criterion 2.6; (3) a generating resource that is connected at less than 100kV is designated per CIP-002, Attachment 1, Criterion 3.4; or (4) 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 2.10.

For an unplanned change resulting in a new BES Cyber System or a higher categorization for an existing BES Cyber System, the new or changed categorization to the BES Cyber System shall become effective 24 calendar months from the date of notification or detection of the unplanned change. By that time, the Responsible Entity must apply all Reliability Standard requirements applicable to its new or changed categorization to the new or existing BES Cyber System.

For unplanned changes resulting in a higher categorization for an existing BES Cyber System, the prior lower categorization shall remain effective until 24 calendar months from the date of notification or detection of the unplanned change.

For requirements that contain periodic obligations, initial performance of those new obligations following a planned change shall occur within the first period following the date the new BES Cyber System could adversely impact the BES or the date the existing BES Cyber System meets the new impact criteria in Attachment 1. Initial performance of those new obligations following an unplanned change shall occur within the first period after 24 calendar months from the date of notification or detection of the unplanned change.

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.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 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.

BES Cyber Systems

The term "BES Cyber System" provides a convenient level at which a Responsible Entity can organize its documented implementation of the requirements and compliance evidence. Responsible Entities can use 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 characteristics 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 more precise time horizon than "Real-time," 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 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 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, Section 1 or Section 2, and listed in Section 3default 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 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 its Reliability Coordinator, Planning Coordinator, or Transmission Planner 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) or automated switching System that operates BES Elements, that if destroyed, degraded, misused or otherwise rendered unavailable, would 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.

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.

[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.

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 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 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 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 SOL's & 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 Situation 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

The Inter-Entity coordination and 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 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, Section 1 or Section 2, and listed in Section 3 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 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, 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, whose purpose is "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 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 Bas 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 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.

  IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for Remedial Action Schemes as medium impact. Remedial Action Schemes 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.

- 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 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 500kV 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 Attachment 1 of NERC's "Integrated Risk Assessment Approach – Refinement to Severity Risk Index" document, 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 include BES Cyber Systems for those Transmission Facilities that have been identified 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 Remedial Action Schemes (RAS) or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs 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. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or

Facility. In the drafting of this criterion, the drafting team sought to include 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. It should be noted that those qualifying systems which require a human operator to arm the system, 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.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System 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, but are offered as components of an ancillary services market 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 would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

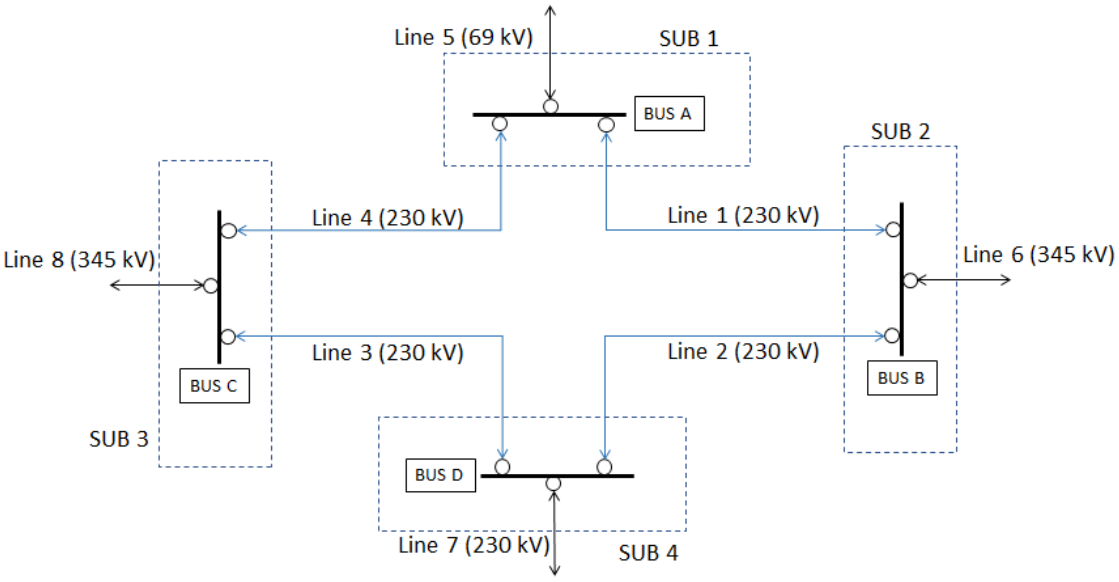
  The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at an appropriate 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.

<u>Criterion 2.12 Examples:</u>

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

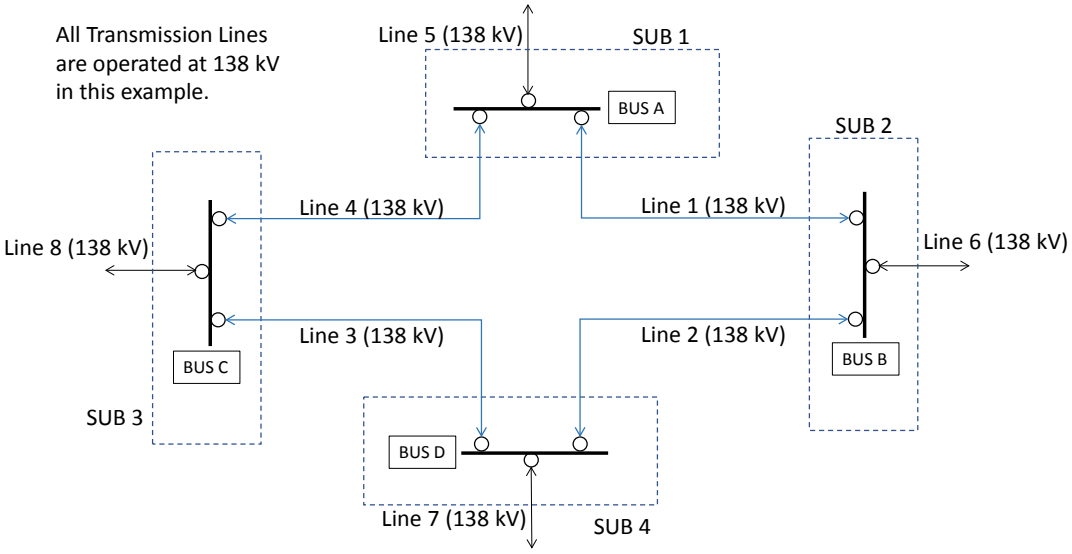
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in 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."

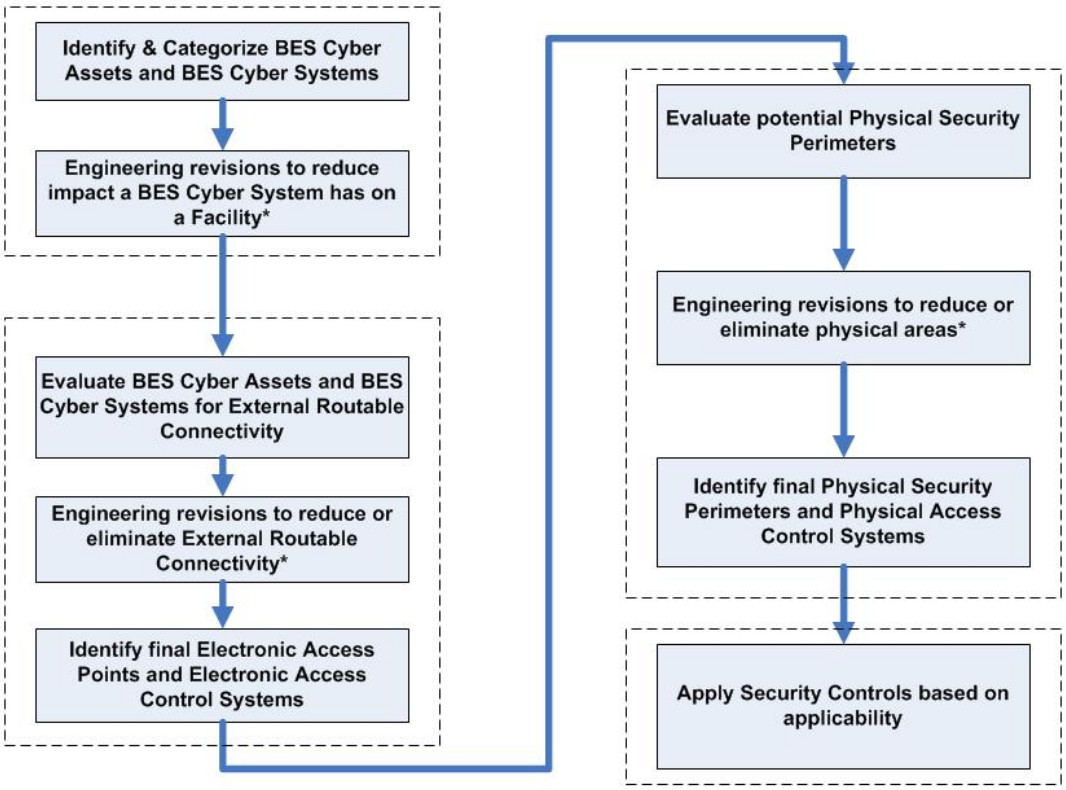
- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default 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 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.

Overview (Generation Facility)



* - 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.

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Implementation Plan

Project 2016-02 Modifications to CIP Standards
Reliability Standard CIP-002-6

Applicable Standard(s)

- Reliability Standard CIP-002-6 – Cyber Security – BES Cyber System Categorization

Requested Retirement(s)

- Reliability Standard CIP-002-5.1a – Cyber Security – BES Cyber System Categorization

Prerequisite Standard(s) 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

General Considerations

This Implementation Plan includes a phased-in implementation date for Criterion 2.12 in CIP-002-6, Attachment 1. This allows Responsible Entities[1] a longer implementation period if the revisions to the Criterion would result in a higher impact level categorization of a BES Cyber System. The phased-in implementation date is only for changes resulting from the revisions to Criterion 2.12; other changes in impact level for BES Cyber Systems are covered in Section 5.1 planned and unplanned changes in CIP-002-6.

[1] As used in the CIP Reliability Standards, a Responsible Entity refers to registered functions listed under Applicable Entities.

Effective Date and Phased-In Implementation Dates

The effective date for proposed Reliability Standard CIP-002-6 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 (i.e., an entire Requirement or a portion of it), the additional time for compliance with that section is specified below. The phased-in implementation date for those particular sections is the date that Responsible 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 CIP-002-6 – Cyber Security – BES Cyber System Categorization

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 immediately 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 immediately after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Initial Performance of Periodic Requirements

Responsible Entities shall initially comply with the periodic requirements in CIP-002-6, Requirement R2 within 15 calendar months of their performance of Requirement R2 under CIP-002-5.1a.

Phased-in Implementation Date for CIP-002-6, Requirement R1, Attachment 1 Criterion 2.12

If the revisions to Criterion 2.12 result in a higher impact level categorization of a BES Cyber System (from low impact to medium impact), the Responsible Entity shall not be required to identify that BES Cyber System as medium impact nor apply the requirements throughout the CIP standards applicable to the higher categorization until 24 months after the effective date of CIP-002-6. Until that time, the Responsible Entity shall continue to identify that BES Cyber System under CIP-002-5.1a, Requirement R1, Part 1.3.

Planned or Unplanned Changes

Any references to Planned or Unplanned Changes in Implementation Plans for any version of any CIP Reliability Standard (i.e. CIP-002 through CIP-014) shall be retired upon the effective date of Reliability Standard CIP-002-6.

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.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **CIP-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.

Justification for VRFs and VSLs

- Requirement R1: The VRF and VSLs did not change from the previously FERC-approved CIP-002-5.1a Reliability Standard.
- Requirement R2: The VRF and VSLs did not change from the previously FERC-approved CIP-002-5.1a Reliability Standard.

Virtualization and Future Technologies

Project 2016-02 Standards Drafting Team: The Case for Change

April 2019

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Executive Summary

What the interconnected power grid does for Bulk Electric System (BES) reliability, virtualization does for the computing infrastructure supporting vital control systems. Individual utilities interconnected their power systems to form a power grid to share spare capacity for meeting demand peaks and surviving contingencies such as generating unit and transmission line outages. Virtualization connects processors, networks, and storage into 'computing grids' that allow our vital systems and applications to meet peak demands and survive outages of individual components.

This is accomplished by abstracting servers, networks, and storage into virtual or logical resources that can be independent of specific underlying hardware such as individual processors, circuits, and disks. A control system and its underlying operating system become a virtual machine and can move to any available hardware. This greatly increases reliability and resiliency of our control systems that support BES reliability.

Virtualization technologies also allow enhanced cyber security controls and the ability to move access controls from the edge of our networks to much deeper inside of them. This is analogous to having generation close to load centers to reduce the susceptibility to outages. These newer security controls allow us to provide tighter security by moving access controls from an outer perimeter closer to the actual code performing reliability tasks.

Virtualization and advanced technology are challenging the way we characterize the Critical Infrastructure Protection (CIP) standards' objectives and how we develop technical requirements. Use of virtualization and advanced technology can provide benefits for implementing both operational and security enhancements to a system. The goal is to require technology-enforced controls as alternatives to the current prescriptive requirements like those requiring a physically structured architecture, without forcing the use of the new technology. The existing standards with their prescriptive language limit the ability to take full advantage of the new technologies. The Project 2016-02 Modifications to CIP Standards Standard Drafting Team (SDT) is drafting new requirements to support virtualization capabilities. This leaves Responsible Entities with the option to maintain a non-virtualized environment and use backward compatibility to preserve current CIP investments and security postures.

This white paper represents the views of the SDT and presents a sampling of virtualization concepts. It explains, in the SDT's opinion, how the use of these concepts is inhibited by some of the CIP standards' definitions and requirements. It also introduces the SDT's ideas on how to address these issues while maintaining compatibility with current state. The goal is to allow for the use of these technologies and newer security controls by removing prescribed "how's" and replacing them with clear "what's" that would allow both current state and these enhanced features.

Introduction

Note: The Project 2016-02 SDT developed this white paper to explain the need to change the cyber security CIP Reliability Standards. This white paper has not been approved or endorsed by NERC and is solely the views of the Project 2016-02 SDT.

In the history of the CIP standards, industry has seen many versions and changes. Some have been straightforward and almost self-explanatory. Others, complex and time-consuming to implement. Still others have been foundational, like the 'do-over' change from Versions 1 – 3 to Version 5. Not surprisingly, the prospect of another set of fairly major changes, this time involving virtualization sparks a great deal of industry concern. It raises valid questions about the timing and the drivers of those changes, and whether or not they are truly necessary. The white paper is designed to provide detailed answers to those questions from the viewpoint of the SDT. This introductory section provides a short, high level introduction to the white paper discussion on what brought about the SDT's focus on future revisions to the CIP standards to address virtualization.

Recognizing the continuing growth in technology innovation, many entities in the Electricity Sector have implemented virtualization as part of their CIP programs. Many of these same entities, however, have implemented this new technology without taking full advantage of virtualization's advanced capabilities. There are a number of reasons for this from the constraints of the current CIP architecture to the ongoing ambiguity around how new virtualization technology applies to CIP compliance. Some of those who are implementing virtualization are experiencing a great deal of uncertainty and difficulty around developing implementation strategies that will support compliance and achieve greater reliability and security.

These issues began coming to light following the NERC "Virtualization Summit" in 2015. Ultimately, the Version 5 Transition Advisory Group (V5TAG) heard about the industry concerns and determined that the issues around the standards and virtualization would be best addressed by a drafting team. The Project 2016-02 SDT was assigned the task to address the technological innovation in virtualization within the CIP standards.

The SDT's purpose of incorporating the virtualization concept into the CIP standards is not to merely augment the current standards. The SDT's intent is to better position the CIP standards to be applicable to any future technological innovation. Leveraging the abstraction that virtualization provides will allow the industry to more readily adopt new technology and increase security posture. This paper presents the SDT's case for change to the NERC CIP standards that is needed to allow for the innovative security techniques and new concepts brought about by virtualization.

As virtualization has progressed, many of these types of issues cannot be addressed with Implementation Guidance. Documenting a possible way to implement a requirement is of great value, but Implementation Guidance cannot, for example, change current requirements so they do not prescribe a perimeter-based model, or allow remediation VLANs. It also cannot add new requirements that are needed for issues like management plane isolation or handling shared infrastructure. These new concepts and techniques require changes to the standards to make them viable and to clarify how they should be secured.

Chapter 1: Virtualization Benefits

The most basic concepts of CIP are essentially unchanged from the Urgent Action 1200 standard in 2003. The primary focus of those standards was the "critical cyber asset"; an "electronic device" such as a server, workstation, or relay as a physical object. It had an operating system, always on and performing its function, and communicating with other components over routable protocols. It was protected by traditional firewalls at the network edge looking at source and destination protocol addresses and ports as the only mechanism by which to make network access control decisions.

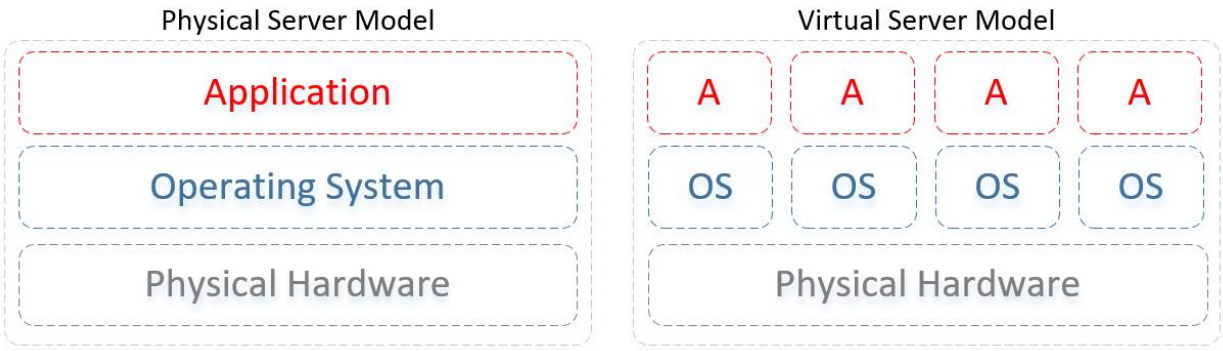


Figure 1

Today, virtualization has changed this scenario. With virtualization, physical devices are no longer the primary units of organization. An entire control system infrastructure can be virtualized (such as "software defined data centers") and only exist as logical constructs. An EMS database server may never exist as a discrete physical object. With containers (operating system emulation), there may not be a concrete tie between application logic and an operating system. Virtual machines can be created and destroyed dynamically and are neither always on, nor tied to specific hardware. Workloads may mirror their information for reliability purposes across great distances without using routable protocols. With micro-segmentation, network access control lists are now much more granular than IP addresses at a perimeter. They are enhanced by policy-based control templates enforcing access at a "user to workload" level throughout the system infrastructure. Electronic access control may no longer be based solely on routable protocol addresses or found only at an ESP boundary.

Benefits of Virtualization

Virtualization technologies bring many reliability benefits to BES Cyber Systems (BCS).

- Increased uptime, very fast recovery capability and flexible architecture that can instantly adapt to changing workloads.
- Virtualization allows for racks of CPUs, memory and disks to be tied together with high speed mesh networks and viewed simply as raw computing resources.
- If the workload on a particular virtual server is nearing capacity, the infrastructure orchestration system can create and configure an additional server on the fly, bring it online to help with the peak workload, and then destroy it when it is no longer needed.

- If a physical machine runs out of resources, the workload can be moved to another physical machine dynamically based upon relative load. When a virtual server or workstation is not in use, it is similar to a physical server that is powered off.
- This flexible and dynamic architecture also allows improved security controls such as those provided by micro-segmentation.
- Users can be granted access to specific workloads that can be placed dynamically throughout the infrastructure with managed access to provided services.

More secure, more reliable, cost effective technology solutions

New and innovative security capabilities continue to evolve to address current threats, particularly in virtualized environments. These capabilities can increase the security of hosted BES Cyber Systems. For example, *distributed firewalls* based on software defined access policies can enforce access controls at a much deeper level within the infrastructure to help prevent an attacker's lateral movement through the network. *Privileged introspection* allows security service such as anti-malware, to operate in a tamper-proof way outside of the instances they protect. *Zero trust models* allow communication to be protected end to end between individual processes across cyber assets without having to trust that devices in the path (such as all firewalls and switches) are configured correctly to protect the data. We'll consider each of these and other examples in more detail to show the benefits and the case for change in the CIP standards.

Chapter 2: Virtualization challenges in the NERC CIP Standards

Virtualization brings benefits to reliability and resiliency of our BES Cyber Systems. It also brings challenges with determining how some of the newer concepts fit within the framework of the NERC CIP standards. Some of these newer techniques and concepts are:

- Identification of Virtual Cyber Assets
- Distributed Firewalls vs. Perimeter models
- Zero Trust models
- Virtualized Firewall Interfaces
- Virtual Storage challenges
- Management Plane Isolation
- Privileged Introspection
- Remediation VLANs

Each of these topics will be covered in detail in the following sections.

Identification of Virtual Cyber Assets

One of the issues requiring change within the CIP standards is the need to clarify the treatment of virtual machines (VMs) under today's definitions. The foundational term Cyber Asset is defined as "Programmable electronic devices, including the hardware, software, and data in those devices." This definition, since it includes the hardware, does not fit with virtualized environments. A literal use of this foundational definition would mean a server hardware platform may be a BES Cyber System, the hypervisor software could be the "operating system", and all the virtual machines running on the hardware are applications or simply data. The CIP-007 requirements, most of which are aimed at an operating system instance, would not be applied to these virtual machines since they aren't hardware. This is referred to in the Figure 2 as the "Physical System w/Software Model."

To require that VM operating systems be classified correctly, the tie between a virtual machine and the hardware needs to be clarified. The standards and their associated definitions need to clearly support the "VM as a CA Model" (Virtual Machine as a Cyber Asset) as pictured in Figure 2. Here it is clear that the physical server hardware and the hypervisor are in scope and each VM is subject to requirements such as CIP-007.

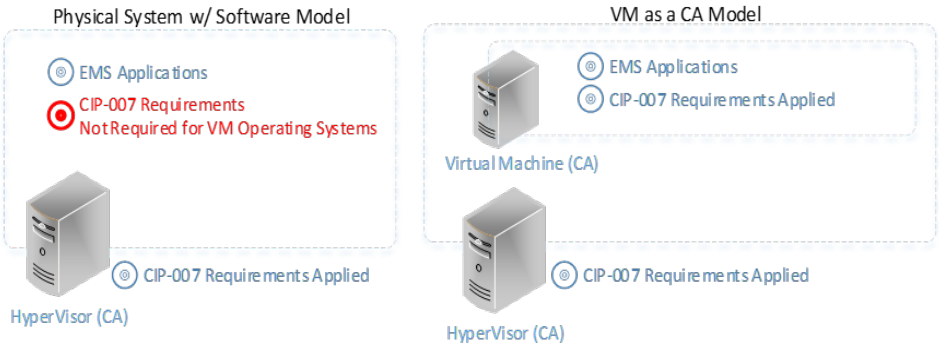


Figure 2

The Cyber Asset definition assumes a 1:1 relationship between a BES Cyber Asset and its hardware. Virtualization, however, breaks that concept because in some cases hundreds of virtual BES Cyber Assets can share a pool of hardware resources (compute, network, and storage). The outdated concepts need to be changed to recognize the one-to-many relationships that are now possible between a BES Cyber Asset, an instance of an operating system supporting applications, and the underlying hardware so it is clear how each is to be treated. There are three different types of asset classes involved in today's BES Cyber Systems:

- Self-contained devices that are composed of dedicated hardware, some form of operating system or firmware, and the application code. This is the traditional definition of a Cyber Asset and applies to things such as digital relays, RTUs, physical operator workstations and dedicated physical servers.
- Virtual "cyber assets" composed of an operating system and applications or containers minus any dedicated hardware. These types of assets are logical or virtual constructs by nature and exist only in memory or files. They can, however, appear from a network perspective the same as any other host.
- Shared Infrastructure consists of the hardware resource pools (compute, network, storage) and is shared by virtual cyber assets and can host numerous virtual cyber assets, networks, or storage locations.

The current CIP standards only recognize the first class and changes are needed to properly address the other two. This will allow BES Cyber Systems, which can be composed of all three asset classes, to be properly identified and classified and the proper requirements applied to each one.

Distributed Firewalls vs. Perimeter Models

Distributed firewalls based on software defined access policies can enforce access controls deeply within the infrastructure to help prevent an attacker's lateral movement through the network. The CIP standards (CIP-005) today require a perimeter-based model as shown in the left side of Figure 3. It has an Electronic Security Perimeter (ESP) as a logical border around a group of cyber assets, and defined interfaces (on a firewall for example) as an Electronic Access Point (EAP). This perimeter model is a prescriptive topology, and for many scenarios is still a valid way to perform network security. What may be prescribed, however, for a small network of similar cyber assets may not be ideal for a large network of virtualized BES Cyber Assets.

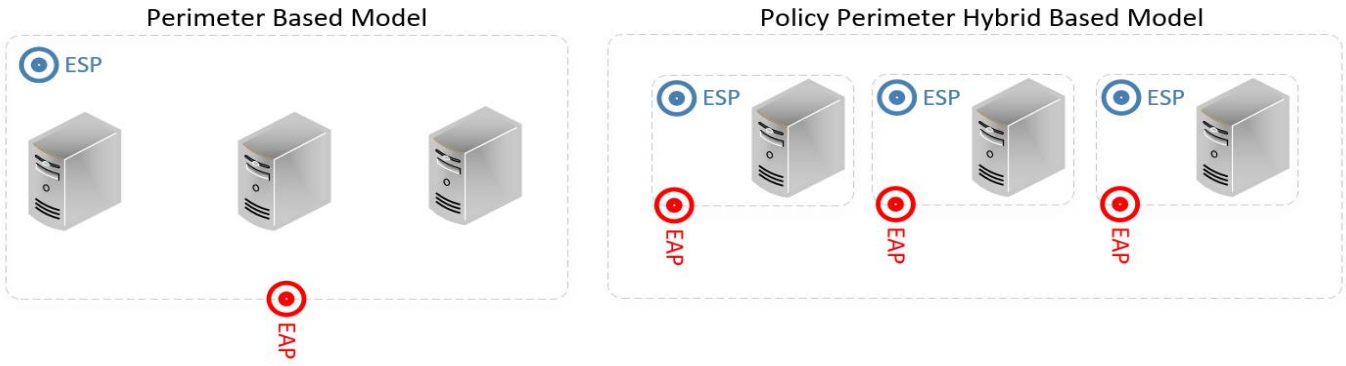


Figure 3

The issue is that network access is permitted or denied at the outer EAP "gate." Even if access is only needed to a single cyber asset inside the perimeter and a strict rule is instituted at the EAP "gate" to allow someone access to that single cyber asset, that control is implemented only at the gate. Once inside the perimeter, there are no network level access controls that would prevent hopping ("pivoting") from that cyber asset to all other cyber assets inside the perimeter. Attackers today depend upon this; if they can get a foothold

on a single cyber asset inside a perimeter they can work over time to move laterally within the environment from there.

Virtualized environments, especially those of cloud providers that support tenants from various customers, had to be designed to implement new, more granular security techniques to not only mitigate this threat but to also keep customer's workloads totally isolated from one another. These new techniques are philosophically simple – every cyber asset is inside its own "perimeter" and the EAP "gates" are specific to each virtual cyber asset. This is shown on the right side of Figure 3 in the "Policy Perimeter Hybrid Based Model." In this model, network access is controlled at an individual cyber asset level and access to a single cyber asset gives you no additional access to any other cyber asset. An attacker's ability to move laterally or pivot in this environment is greatly reduced. These techniques are also configured at a *network access policy* level and the infrastructure dynamically implements it at various levels throughout the entire infrastructure. Even as these cyber assets move dynamically within the infrastructure, these access controls move with them. All of this, however, precludes the ability of administrators to provide a "list" of potentially hundreds or thousands of ESPs, EAPs, or the discrete rules per EAP. This is because it is all dynamically generated by the infrastructure to control access in accordance with a higher-level access policy.

These same techniques can be used to mitigate the same risks within virtualized CIP environments. The problem is that CIP requires the perimeter model with EAP "gates" as the only prescribed way to implement network level security. The SDT is planning to change the CIP standards and definitions in a way that does not *preclude* the perimeter based model, but also does not t *prescribe* that model as the only way. For example, the language in CIP-005 R1.2 "All External Routable Connectivity must be through an identified Electronic Access Point (EAP)." This creates an issue since historically this is a physical interface on a physical device. More current, virtualized architectures distribute the policy enforcement tasks to multiple devices and each of them validates that the network communications passing through it are permitted. The current standards do not align with these architectures because there is no single interface identified that is responsible for policy enforcement.

Identifying non-routable EAPs and the OSI Model

Related to the ESP issue, today's CIP Standards are limited to prescriptive topologies even as potentially more secure, reliable and cost-effective solutions are available. ESP's are defined today by the access provided at the network layer (OSI Layer 3) and are therefore limited to making access decisions based on routable protocol addresses. This method does not support security evaluation or compliance via security solutions at any of the other layers of the OSI model. This presents two issues:

- There may be network access into and out of the perimeter at different layers other than by a purely routable protocol that allow for things like high speed replication of data. This will be discussed further in the "Multi-Site Data Center Extensions (Super ESP)" section below.
- Virtualized environments have much more context and can enforce network access control at more granular levels in much better ways. These include by user, process, or certificate and are not limited to only a source/destination IP address of a routable protocol.

In many environments today, the perimeter model is sufficient and routable protocol addresses are all an entity has to make access control decisions. However, the standards should not prescribe this as the only way and should allow entities to use these more granular controls that may operate at other layers.

Zero Trust Models

The zero trust network model is a new and different way of thinking about network security. In most cases it can be implemented within the security model that an entity currently has deployed.

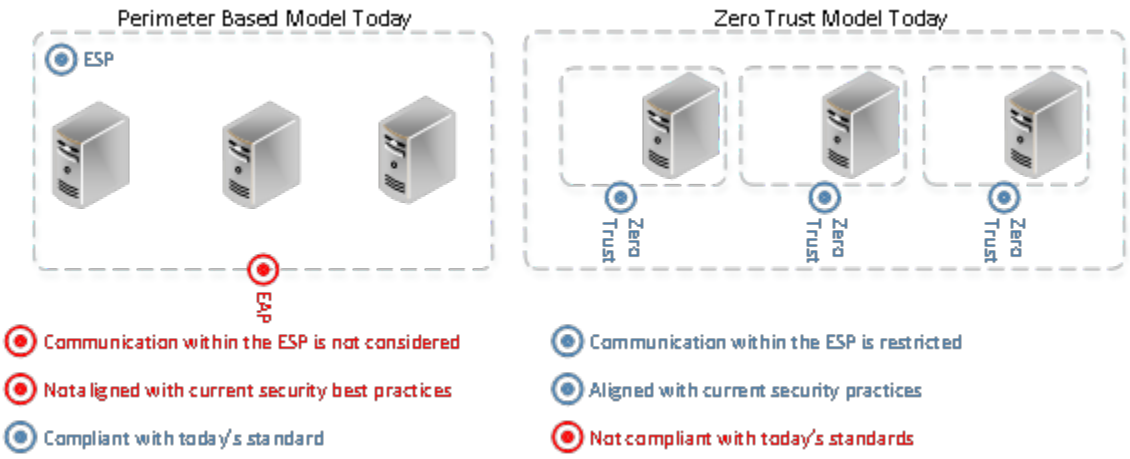


Figure 4

Most entities have a perimeter model deployed, which is what the current ESP model requires as in Figure 4. Traditionally, this consists of a firewall (or firewalls), with a single path into the network (EAP). This model protects the BES Cyber System indirectly, by protecting the network topology. This access point is protected by rules and policies that tell the firewall what kind of traffic to pass and what kind of traffic to stop. This model can be loosely compared to a gated community, where the fence is the firewall, and the gate and security guard are the access control.

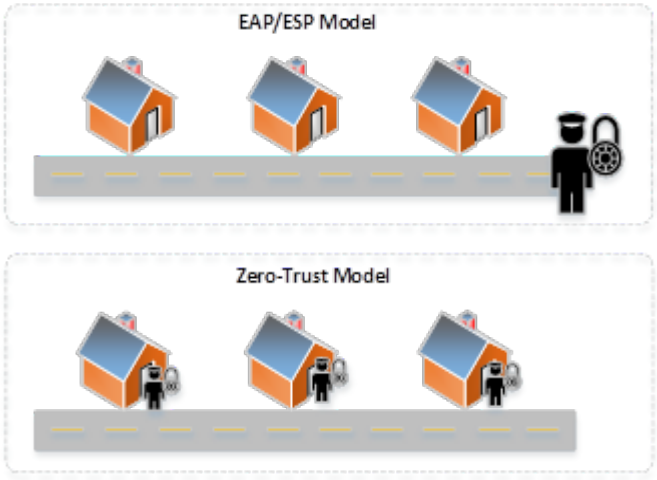


Figure 5

The overarching problem with this model is that if attackers should get past the firewalls and through the gate, they would have free rein throughout the network and could pose a serious threat to other BES Cyber Systems within the ESP.

A zero trust model brings the protection directly to the cyber asset or even to the process level. Using network policies, whitelisting, certificates, and other technologies, the ability of an intruder to move around is severely restricted. A zero trust model usually starts with simple items like restricting network traffic to the device except that which is necessary for it to perform its job function. It also restricts what logins can access the device. Finally, it introduces more complex ideas such as digitally signed executables, restrictions on what time a process can be started, and end to end encrypted traffic, even within the local network. This model protects the BES Cyber System directly by protecting the workloads, the devices and the topology. Unfortunately, this model is very difficult to describe using the current language constructs of the CIP requirements.

Referring to the gated community analogy in Figure 5, this would put a fence in every yard, a lock on every door and an alarm system in every house. This effectively isolates the intruder to the public areas of the neighborhood.

Virtualized Firewall Interfaces ('Firewall on a Stick')

As the use of network segmentation grows and firewalls are used to control traffic flows between the network segments, firewalls need higher densities of interfaces. To obtain these higher densities, products today rely on fewer physical ports and instead use virtualized network interfaces to emulate many physical interfaces. Some modern firewalls are service modules (a "firewall on a stick") installed in a switch or router where virtual interfaces are the only option to route traffic to and from the firewall as shown in Figure 6.

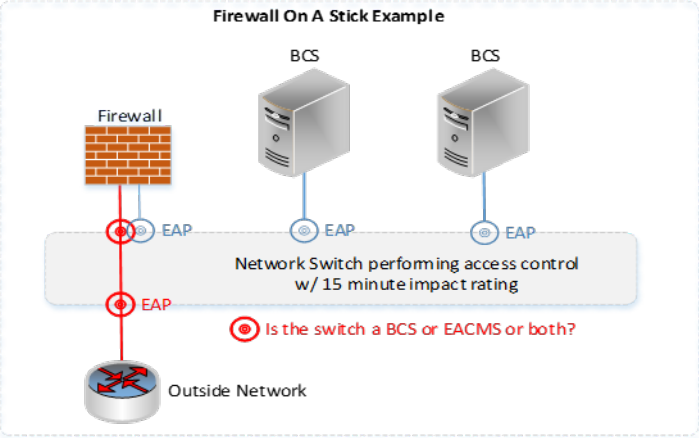


Figure 6

The CIP standards are ambiguous on how to properly identify these assets. If this were simply a network switch allowing two BES Cyber Systems to communicate with each other with a 15 minute impact if the switch is unavailable, then the switch itself is part of a BES Cyber System. In this example, the entity wanted to increase security of the communications between these two systems. To accomplish this, it put each BCS on its own network segment so it can filter all traffic between these two systems through a firewall. A "firewall on a stick" is installed in the switch and the ports on the switch are divided into virtual networks so the traffic between different segments is directed to the firewall and controlled. Since the firewall either has no physical interface or may use its few physical interfaces for redundancy, the outside network must connect to the same switch and that port is configured to the "outside" interface of the firewall. All communications to and from the outside network and between the two BCS are all controlled via the firewall. The entity has increased the security of these systems, but it is now undecided on how to identify the cyber assets in this scenario. As one example, are all the network switch ports now EAPs on an EACMS, or is this switch still just a part of the BCS? As access control is pushed deeper into networks as in this example, the current paradigms are ambiguous. The answer may lie in identifying new asset classes and developing new objective requirements that do not include prescriptive network topology assumptions. Trunks and sub-interfaces are common network technologies to aggregate data streams and better utilize limited physical interfaces[1].

[1] Trunking is the use of a single link to aggregate multiple data streams. This technology is widely used in networking and telecommunications. Sub-interfaces allow for multiple LAN segments to share a common physical interface.

Virtual Storage Challenges

As we move to virtual storage, there are issues with some of today's CIP concepts. For example, the CIP-011-2, requirement R2 restricts unauthorized access to BES Cyber System Information on systems meant for reuse outside of the CIP environment or systems meant for disposal. This causes a challenge for virtualized infrastructure. Today, when disposing of a physical medium or high impact BES Cyber Asset, access to BCSI can be restricted by sanitizing or destroying the media associated with the physical asset. If storage media is provided from a Storage Area Network (SAN) or Network Attached Storage (NAS) array, there may be no easy way to identify the specific drives where the data might have been stored. Additionally, there is no significant benefit to pulling drives from an array to sanitize or destroy them if there is another way to manage this media.

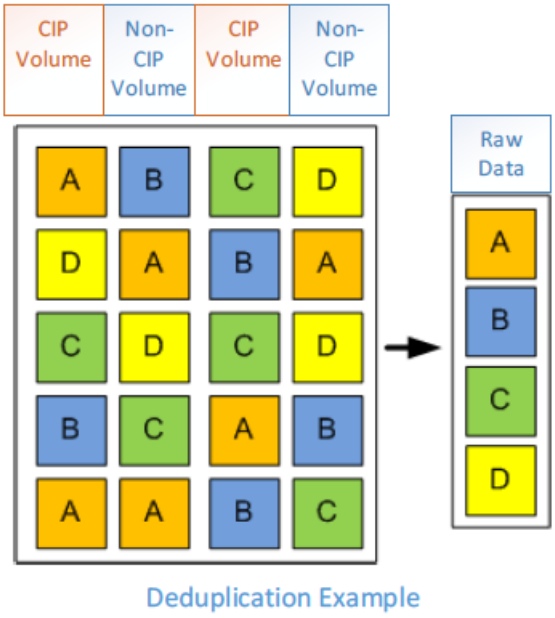


Figure 7

To extend this challenge further, many SAN and NAS environments can de-duplicate and move data to various storage tiers within the array to optimize access times and reduce latency. This process analyzes the data in small enough chunks to create single instances of data that are used within multiple volumes that may be assigned to any number of devices. The chunks with the highest access rates are then placed on fast storage media because the data is constantly referenced. This effectively causes data re-use if storage media is shared between CIP and Non-CIP assets even when the information contained within these de-duplicated chunks is not readily retrievable individually.

That was one example. The CIP standards were built on a paradigm of disk storage being physical disks dedicated to a Cyber Asset. Updates to the standards are needed to reflect the realities of virtual storage technologies that are in use today.

Management Plane Isolation

Because virtualized servers, networks, switches, firewalls, and storage are logical constructs, controlling access and communications to the management plane of these systems is imperative. Access to the management plane (interface/console/etc.) allows a user to create, modify, or delete these objects or entire infrastructures from one place, or move objects from one zone or network to another. Administrative level or "management plane" access to the hypervisors is therefore absolutely critical to the security and reliability of the hosted systems. These types of access must be brought into the scope of CIP standards if hosting BES Cyber Systems and will require changes to the CIP standards.

Another challenge of the perimeter model is it can drive less secure topologies in order to provide clear adherence to the perimeter model. In Figure 8 below on the right is the desired separation between the management plane of a virtualized environment and the production or "data plane". The management port of the BCA is connected to a switch on the management network. The production network switch is connected to the network interface on the BCA. This creates two different network paths to the BCA: one for normal production traffic and a separate network path with separate access controls for administrative or

management plane access. It is unclear, however, if the BCA has now created two ESP's with two EAPs, and whether or not it is now an EACMS. It is not functioning as an EACMS, but from the topology it appears as one. The prescriptive CIP model may create a temptation to place the management interface into the production ESP as in the picture on the left. This is very clear from a CIP standard adherence perspective but is the less secure choice.

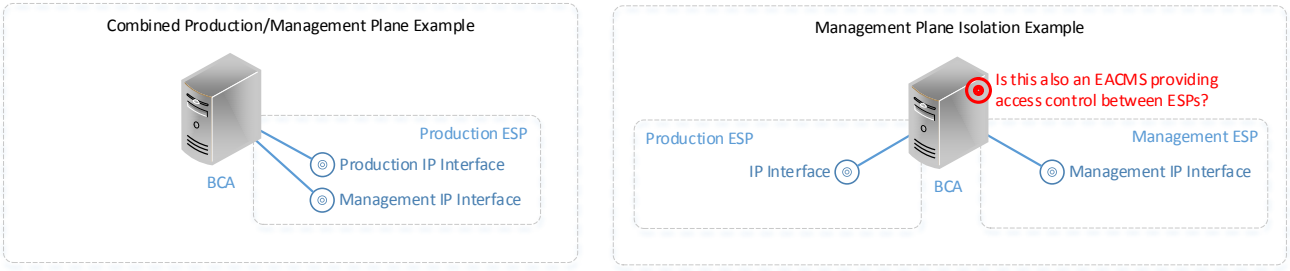


Figure 8

Privileged Introspection

Privileged introspection allows security services, such as malware detection, to be performed outside of the operating system and applications it is protecting in a tamper-proof way. Previously, malware that could gain elevated privileges on a cyber asset could then disable security services such as anti-virus solutions running on the same OS. Virtualized environments, however, can allow privileged introspection where anti-virus or application whitelisting services run as part of the hypervisor; outside of the operating system they are protecting so malware with elevated privileges inside the OS cannot reach them. Another benefit of privileged introspection is it allows integration with distributed firewalls because it can inspect network traffic entering or leaving virtual machines and make decisions with vastly more context. For example, these firewalls can control access not simply at a network address level (IP source/destination) but down to the level of a process with a particular certificate.

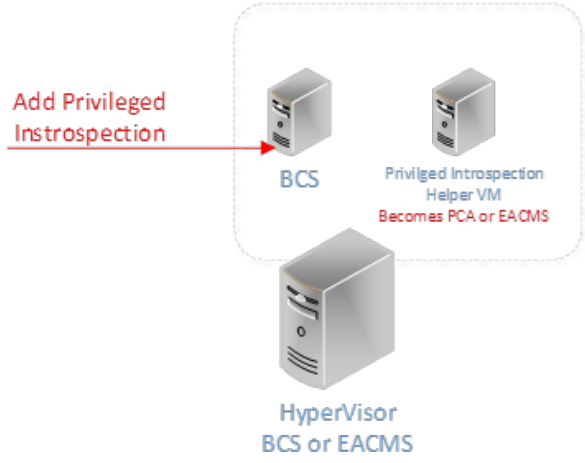


Figure 9

Even though the current CIP-007 R3 is already written at a security objective level and can work with privileged introspection, there can still be CIP standards issues brought into play. If this functionality uses "helper VMs", it is not clear how to identify and classify these under the current CIP standards. Since the status of malware detection is now outside the VM's, it requires grouping the VM's protected by privileged introspection into a particular BES Cyber System.

Remediation VLANs

As another example of the need for change in the CIP standards brought about by new virtualization technologies, CIP-010 R3.3 states, "Prior to adding a new applicable Cyber Asset to a production environment, perform an active vulnerability assessment of the new Cyber Asset..." This is a valid requirement that cyber assets be in a CIP compliant state before being added to a production CIP environment. The issue is that this is written with the idea that an entity's new cyber asset is a separate physical asset it can configure in a compliant state prior to it being placed in a "production environment" and connected to a production network.

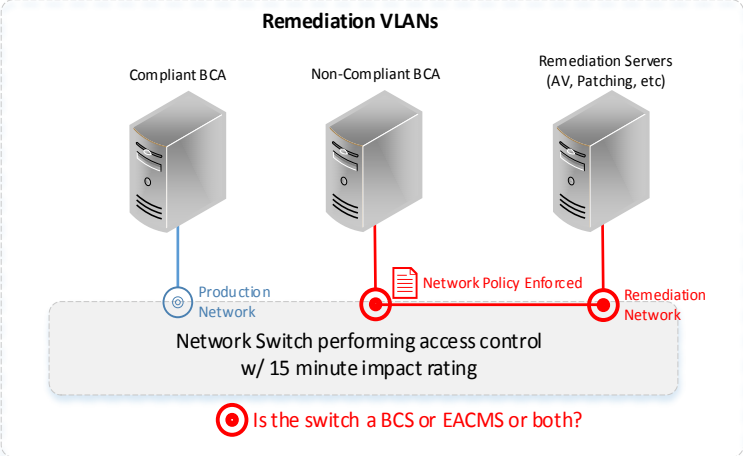


Figure 10

Virtualized environments, however, allow for a concept known as remediation VLANs. When a new cyber asset, such as a server or operator workstation is instantiated from an image, it is already "in" a production environment. However, it is brought up in a remediation VLAN where its network visibility is restricted to those services (patching, anti-virus updates, etc.) that it needs to assess vulnerabilities, update itself, and become compliant. Only after it is fully compliant with policy, can it be moved to a production VLAN where it has the full network visibility. Should this virtual machine become non-compliant with the network policy, it is moved back to the remediation VLAN to be made compliant again. This is an advanced security control, beyond what CIP-010 envisions, where real time checks are performed to ensure a cyber asset is compliant with security policy. The way the CIP standards are currently written, however, could preclude such advanced controls since this Remediation VLAN must be either part of an ESP or a separate ESP in order to host BCAs per CIP-005-5 R1. Requirements such as those in CIP-005 and CIP-010 need to be modified to allow for these more advanced features and controls.

Multi-Site Data Center Extensions (Super ESP)

There are technology solutions now that support very high levels of resiliency, so much so that virtual machines can be seamlessly moved from physical infrastructure at one data center across great distances to physical infrastructure at another data center. For example, control center functions could move easily and seamlessly from a primary control center to a backup control center across town or across the state. For this to work, an entity would use tunneling protocols that make the two data center networks appear as one local network ("layer 2 adjacency"). You've "stretched" a LAN across a WAN. The issue with CIP is that it assumes a LAN at each site with a defined ESP and access control at a point on that ESP at each site, with all the WAN communications equipment in between these ESPs exempted from scope. In

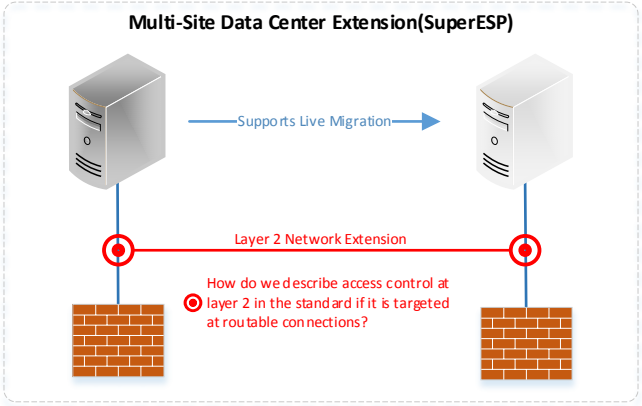


Figure 11

this situation, however, we have a single “local network” stretched between different sites creating at one level a “Super ESP”. Complicating the issue is that underneath this logical network extension, the data may actually ride in encrypted tunnels created at a routable protocol layer. At that layer, firewalls on an ESP can’t really provide any security, but that is prescriptively where the CIP standards say it must be done.

Chapter 3: Future Concept Example

Previously the proposed solution to address these issues with virtualization was a full embrace of the cyber system concept (retiring device level terms like Cyber Asset and BES Cyber Asset) and writing the technical requirements (e.g. CIP-005, CIP-007, CIP-010) at a more objective level. However, through industry feedback several important issues came to light:

- Eliminating the BES Cyber Asset definition and moving to the BES Cyber System as the sole foundational object with no further granularity would cause a complete overhaul and "do-over" of entities' CIP-002 processes with insufficient benefit for the effort required.
- Requiring grouping systems by function exclusively conflicts with a number of different ways the industry has used the systems grouping flexibility; for example to group all Cyber Assets of a like operating system for patching purposes.
- Stating security objectives in requirements must be at a level where they are clearly measurable.

With these issues in mind, the future concept is to leave the foundational definitions largely unmodified. A "Cyber Asset" would remain as-is and be inclusive of the hardware as it is today. However, including the hardware for virtual cyber assets does not work, even though it needs to be protected the same as a discrete physical cyber asset. To resolve this the SDT will create a separate definition to capture virtual cyber assets so that they can be added to the applicability of the appropriate requirements. The hardware that provides compute, network, and storage resources would become its own new term to capture shared infrastructure and allow requirements to be written for risks unique to that environment. BES Cyber Systems would remain as-is and allow for all the various ways entities have used that concept to date.

The direction remains to establish objective level requirements but these need to be written at the appropriate level. For example, if CIP-005 R1 were written as "Mitigate the risk of unauthorized network access", it is certainly an objective but is too high level to be measurable. No one would be able to state when, or to what degree this objective had been accomplished. If CIP-005 R1 were written as "Only allow known valid layer 3 IP addresses into or out of the network and implement this only at a Cyber Asset interface located only at the network edge", it would be a prescribed topology and a prescriptive "how." This should be avoided as it precludes much of the newer technologies presented in this paper. The latter is essentially the CIP-005 R1 of today and is one of the primary requirements that needs to change to remove this prescriptive topology and "how's".

An example of an alternative objective requirement that clearly describes a measurable "what" but avoids prescriptive "how's" for CIP-005 R1 could conceptually be:

> *Deny all access to and from the networks on which high and medium impact BES Cyber Systems and their associated PCAs are connected and only allow network communication that has documented access permissions including the reason for granting access.*

This is a much clearer objective to accomplish but it avoids telling the entity how or where they must implement it or how their network must be architected. As for backward compatibility, an entity could still define an ESP with designated EAPs and provide firewall configurations as they do today. However, an entity using the advanced virtualization techniques from earlier in this paper, or future techniques to control network access that have not yet been contemplated can still show they meet this same objective.

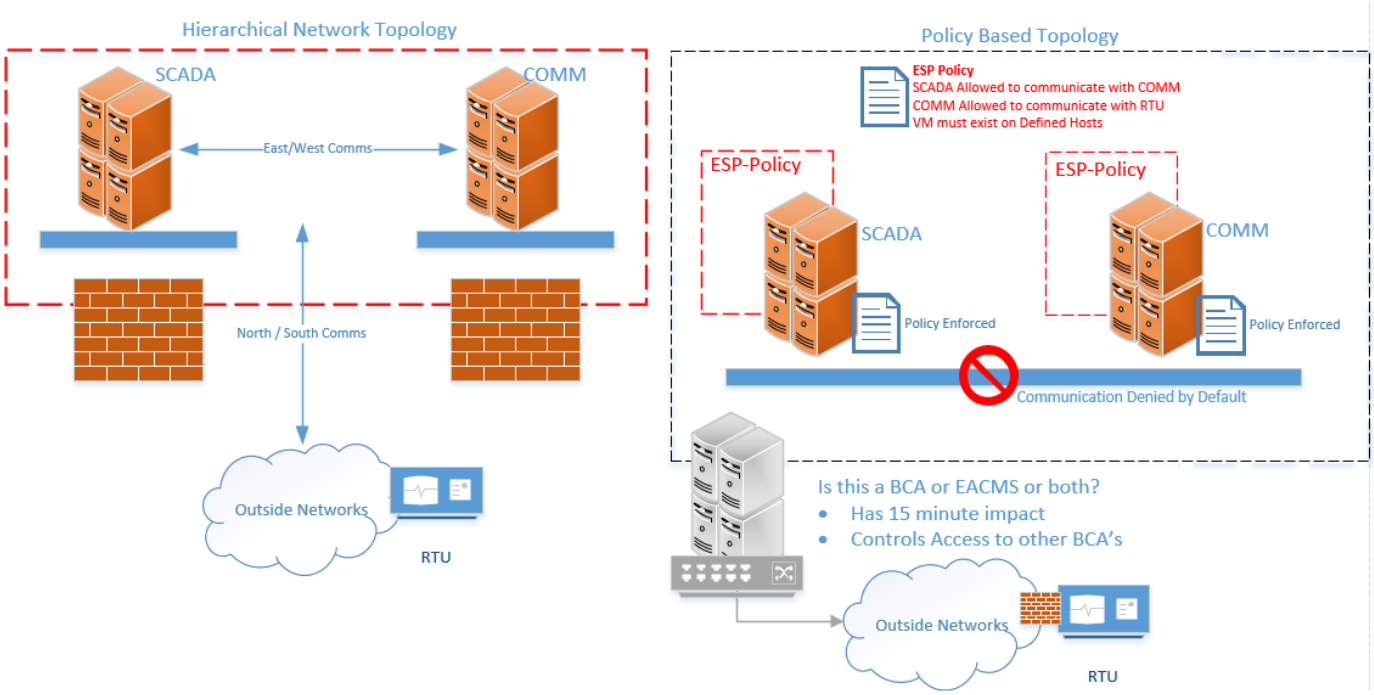


Figure 12

As shown in Figure 12, the current state ESP/EAP model on the left continues to be a valid architecture and topology with which to meet the objective. It is prescribed under the current requirements, but is not the ONLY way to accomplish the objective. On the right is a policy-based model in a fully virtualized system which can also accomplish the same objective once it is no longer prohibited by the requirement language. It has no distinct EAP; no distinct 'point' or 'interface' where the access controls are implemented. This is because the access policy is implemented throughout the infrastructure and the controls move with the virtual workloads. Access control is applied at a deeper level, closer to the functions that require protection and the policy allows no communication to occur that isn't explicitly allowed. The objective stated in the requirement can be met in either scenario.

For the asset classification, nothing changes for the architecture on the left. For the virtualized architecture on the right, the concept is to clarify that the systems in orange are virtual cyber assets, but without including the hardware. They exist as a virtual entity and need much of the same protection as a physical cyber asset. The systems depicted in grey are the Shared Infrastructure, a new asset class that hosts virtual cyber assets. Having these additional asset classes would allow the CIP standards to require protection appropriate to each class, whether a discrete physical system, a virtual cyber asset, or shared infrastructure hosting many virtual BES Cyber Systems.

Chapter 4: Conclusion

This paper has stepped through the benefits of virtualization in terms of increased reliability and resiliency for BES Cyber Systems. It also discusses how virtualization provides newer techniques for securing access to those systems, such as distributed firewalls and zero trust models. It has highlighted some of the issues created by several of these concepts and the required topologies contained within today's CIP requirements. Many of these issues revolve around the proper classification of cyber assets in virtualized environments and having asset classes whereby requirements can be properly scoped. Several other issues revolve around the prescriptive "how" of today's CIP-005 ESP/EAP model, the CIP-010 data requirements in a virtual storage world, or how CIP-011's requirements need minor changes to allow for technologies such as remediation VLAN's.

The CIP standards require some changes to:

- Address risks unique to virtualized environments such as the sharing of hardware resources and management plane access.
- Provide clarity around how to identify and categorize the various types of cyber assets in a virtualized infrastructure and scope requirements appropriately.
- Allow entities to fully implement newer security techniques in these environments that can provide higher levels of access control that are easier to manage, and don't require purchasing extra hardware to show compliance with prescribed topologies.

Many of these issues can be addressed as shown in the CIP-005 R1 example concept, where the prescriptive 'how' has been removed and replaced with a clearly stated security objective – one that fully allows for current state but also allows these newer techniques. Developing technology-agnostic security objectives can not only solve the issues presented by today's virtualization technologies, but also help address future issues brought about by technologies that aren't even contemplated today.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Virtualization and Future Technologies: Case for Change Webinar Q & A

Project 2016-02 Modifications to CIP Standards

The Project 2016-02 Modifications to CIP Standards Drafting Team (SDT) held a Virtualization: Case for Change Webinar on April 24, 2019. The following items are questions and answers from the webinar. The SDT encourages industry to review this document prior to responding to the Case for Change Informal Comment period.

Q1. The White Paper states "Here it is clear the physical server hardware and the hypervisor are in scope and each VM is subject to requirements such as CIP-007" (page 3). Is it the SDT's position that this is true for hypervisors ONLY containing EACMS?

A1. No, the Cyber Asset definition is used for all asset classes including EACMS, BCA, PCA, etc. and it is inclusive of hardware. What the SDT is pointing out is that:

- If the Cyber Asset definition is inclusive of hardware and;
- If the entity classifies their VM as a Cyber Asset; then the hardware is included in that definition.

Q2. With the Zero Trust Model, now it looks like it would allow the co-located systems without a separate EAP (gated) around the ESP, and allow VM's to be an EAP/ESP individually and would not be requiring physical segmentation from NON-Compliance systems.

A2. Zero trust is a methodology for implementing access control and integrity. In principle the services on top in this model would not even trust their own underlying architecture. We will talk later in the presentation about the SDT's strategy for handling mixed-mode or mixed trust systems through the use of new requirements targeted at new definitions.

Q3. Since a Cyber System can be one CA, doesn't the model on the right just provide defense in depth, like physical security?

A3. An ESP within an ESP? The SDT does not believe the standard should prescribe a particular technology solution to these issues. In addition, within the standard the entity's network access control is only measured at the network edge. We believe the entity does not get credit for the defense in depth strategy, so it does not encourage them to use it.

Q4. As you discussed the BCSI issues, how will this team work with the separate SDT working on BCSI?

A4. Both CIP SDTs will keep open collaboration regarding BCSI through the development of each project.

Q5. The Case for change paper speaks to Distributed Firewalls as a more secure option in a virtualized involvement. Why can't this approach be effectively used in today's environment either behind an identified EAP or have the large ESP broken down into multiple ESPs?

A5. The SDT does not believe the standard should prescribe a particular technology solution to these issues. Within the standard the entity is only measured at the edge and we believe the entity does not get credit for the defense in depth strategy so it does not encourage them to use it.

Q6. To clarify: if a hypervisor hosts EACMS and non-EACMS, is the hypervisor an EACMS? Are the other non-EACMS VMs high watermarked? We've been told EACMS do not high watermark like BCAs.

A6. The SDT believes that how to handle the described scenario is unclear. This is the primary reason that it was presented in the challenges section of this presentation. EACMS relies on the CA definition and the CA definition includes hardware.

Q7. In regards to VLANs on a switch and port security. If I am using a trunk port connecting to a firewall, would this make the switch an EACMS? When any type of port security is used, i.e. mac security or 802.1x ... would this also make the switch an EACMS?

A7. The SDT believes that this is also an area that needs clarity. Through our analysis the switch itself performing the access control could fall into the EACMS category. However, if it has a 15 minute impact it may also fall into the classification of a BCA.

Q8. Why is the SDT working on still addressing hardware instead of addressing the Virtual environment risk (using the highest risk application principle)? SDT is not the first to draft virtual security, PCI council and NIST already have a risk based approach.

A8. The SDT believes that it is not simply addressing the hardware but that the existing definitions are limiting our ability to describe virtual environments. We have been looking to other frameworks as guides to effectively describe these new technologies while maximizing our ability to be backward compatible with existing programs.

Q9. BCSI explanation was very confusing. If SAN is part of the environment, why should not the storage area be the focus?

A9. The SDT is addressing the storage architecture as a core area of virtualization as you will see on many of our drawings. While changes may be needed, we are not directly addressing the handling of BCSI at this time because there is a separate team evaluating the topic.

Q10. For Entities that are moving toward virtualized environments, will the SDT provide some guidance for those moving to it prior to the finalization of the revised standard? Alternatively, will there be a pilot implementation group similar to the V5 TAG pilot?

A10. The SDT plans to provide as much clarification as possible through guidance, outreach, and white papers. Many entities are already using virtualization in their environments and we will try to work with NERC to help provide a smooth transition.

Q11. What is SCI?

A11. Shared Cyber Infrastructure. It is a new definition to target requirements at the shared infrastructure on which virtual objects (machines, networks, and storage) execute (As depicted in grey in the drawings).

Q12. Does the proposed approach for the "shared infrastructure" categorization create a dual standard for compliance between data center (compliance at SCI) and substation environments (compliance at BCA level with ports and services and passwords, etc.)?

A12. The SDT plans to use the new term for Shared Cyber Infrastructure to target applicability within the standards.

Q13. From slide 27, how does the approach to 'deny all access to and from networks, with "networks" being the operative term, permit the use of a zero trust model. Doesn't this still prescribe the gated community model and preclude 'house'-level protections?

A13. The language on the screen was draft and we realize that it may not be the correct target for this requirement. We did want to share this approach with you for your consideration as we continue to draft better requirements.

Q14. How do you address the problem of VLAN hopping/crossover? Do you make a distinction between port based and logic based VLANs?

A14. To date, the SDT has been using the concept of logical isolation that can be created by various means including those you mentioned. The entity would be responsible to prove that their logical isolation is sufficient to meet the requirements.

Q15. Can you clarify the segregation requirements of shared storage? I understand the need for separate hosts for CIP and non-CIP assets - does that mean we need separate storage arrays or will logical access controls that segregate LUNs to hosts suffice?

A15. As we have been describing it so far, we would need to draft a new requirement targeted at the shared infrastructure to create logical separation. Those requirements are not yet complete.

Q16. Are there any lessons learned that will be delivered soon about those challenges?

A16. The SDT has been working on a model we call Pinecone Power, a fictitious entity that will be the foundation for guidance and future lessons learned whitepapers.

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~~ This is the second draft of the proposed standard.

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	11/26/2018 – 01/09/2019
~~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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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	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	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		validated or calculated value.	validated or calculated value.	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

~~Link to the Implementation Plan and other important 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~~ 2 Frequency Response ~~&~~ and 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~~reliability ~~objective~~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), w~~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)	0.41~~949~~	0.28~~091~~	0.40~~673~~	0.94~~69~~	

Resource ~~Contingency~~ Loss Protection Criteria (RLP~~C~~C)*	**3~~4~~,209~~500~~**	**2,85~~74~~0**	**2,750**	**2~~1~~,0~~7~~00**	MW
Credit for Load Resources (CLR)		**120~~300~~**	**1,209,~~400~~****		MW
Current IFRO (OY 2018)	**-1,015**	**-858**	**-381**	**-179**	MW/0.1 Hz
First-Step IFRO**~~IFRO~~	**-915~~-1,002~~**	**-975~~840~~**	**-380~~286~~**	**-211~~179~~**	MW/0.1 Hz
Second-Step IFRO**	**-815**				
Final IFRO**	**-766**				

Table 1: Interconnection Frequency Response Obligations (base year)

**~~These values are updated using preliminary information collected by the Standard Drafting Team.~~These values are evaluated annually for changes in each Interconnection.*

***To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10~~%~~ percent, the ERO will halt the reduction in IFRO until such time~~s~~ that a determination can be made as to the cause of the degradation~~what is impacting Interconnection FRM~~.*

~~*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 FRO~~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:

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

Where:

- Annual $\mathrm{Gen}_{\mathrm{BA}}$ is the total annual ~~"~~o~~O~~utput of g~~G~~enerating p~~P~~lants~~"~~ within the Balancing Authority Area (BAA)~~., on FERC Form 714, column c of Part II - Schedule 3.~~
- Annual $\mathrm{Load}_{\mathrm{BA}}$ is total annual Load within the BAA~~, on FERC Form 714, column e of Part II - Schedule 3~~.
- Annual $\mathrm{Gen}_{\mathrm{Int}}$ is the sum of all Annual $\mathrm{Gen}_{\mathrm{BA}}$ values reported in that interconnection.
- Annual $\mathrm{Load}_{\mathrm{Int}}$ is the sum of all Annual $\mathrm{Load}_{\mathrm{BA}}$ 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.~~ Submit a joint Form 1 with

the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities~~As~~.

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. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. 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 Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the Balancing Authority chooses between 100~~%~~ percent and 125~~%~~ percent 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~~FRSG will need to calculate its stand-alone ~~Frequency Response Measure~~FRM 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 Balancing Authorities' areas on FRS Form 1 as described in Requirement R4.

~~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.~~

~~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~~ in a Balancing Authority area 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.[2] ~~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 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).

~~[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~~

[2] 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.

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~~ 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~~Interconnection. However, the calculation of the Balancing Authority 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 Balancing Authority's 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 Balancing Authority ~~Frequency Response Obligations (~~FRO~~)~~
- Calculate Balancing Authority ~~Frequency Response Measures (~~FRM~~)~~
- Determine Balancing Authority A Frequency Bias Settings ~~(FBS)~~

Target Business Date	Activity
~~April 30~~March 1	FRS 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 FRS 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

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~~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

This is the second draft of the proposed standard.

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

Anticipated Actions	Date
45-day formal or informal comment period with ballot	11/26/2018 – 01/09/2019
45-day formal or informal comment period with additional ballot	TBD
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-003-2**

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-003-2.

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 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 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 30% but by at most 45% or 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 45% or by more than 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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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	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	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		validated or calculated value.	validated or calculated value.	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-003-2 Frequency Response and Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation

The ERO, in consultation with regional representatives, has established a target reliability criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). 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
Max. Delta Frequency (MDF)	**0.419**	**0.280**	**0.406**	**0.946**	
Resource Loss Protection Criteria (RLPC)*	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)		**120**	**1,209**		MW
Current IFRO (OY 2018)	**-1,015**	**-858**	**-381**	**-179**	MW/0.1 Hz
First-Step IFRO**	**-915**	**-975**	**-380**	**-211**	MW/0.1 Hz
Second-Step IFRO**	**-815**				
Final IFRO**	**-766**				

Table 1: Interconnection Frequency Response Obligations (base year)

**These values are evaluated annually for changes in each Interconnection.*

***To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10 percent, the ERO will halt the reduction in IFRO until such time that a determination can be made as to the cause of the degradation.*

Balancing Authority Frequency Response Obligation and Frequency Bias Setting

For a multiple Balancing Authority interconnection, the Interconnection FRO 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:

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

Where:

- Annual Gen_{BA} is the total annual output of generating plants within the Balancing Authority Area (BAA).
- Annual Load_{BA} is total annual Load within the BAA.
- 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.

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
- Submit a joint Form 1 with the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities.

Balancing Authorities that merge or 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 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. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. 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 Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the Balancing Authority chooses between 100 percent and 125 percent 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 FRSG will need to calculate its stand-alone FRM 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 Balancing Authorities' areas on FRS Form 1 as described in Requirement R4.

Frequency Response Measure

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event in a Balancing Authority area 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 the change in its Net Actual Interchange on its tie lines with 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.[1]

The ERO will use a standardized sampling interval of approximately 16 seconds before the 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

[1] 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.

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 Balancing Authority 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 Balancing Authority's 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 to:

- Facilitate the assignment of Balancing Authority FRO
- Calculate Balancing Authority FRM
- Determine Balancing Authority Frequency Bias Settings

Target Business Date	Activity
March 1	FRS Form 1 is posted by the ERO* with all selected events for the operating year for BA usage.
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 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.
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 FRS 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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2017-01 Modifications to BAL-003-1.1

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard BAL-003-2. 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. Please note, the SDT is only proposing to change the VSL for Requirement R1. As a result, justification is only provided for the VSL for Requirement R1

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures; 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 BES instability, separation, or a cascading sequence of failures, or could place the BES 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 BES, or the ability to effectively monitor and control the BES. However, violation of a medium risk requirement is unlikely to lead to BES 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 BES, or the ability to effectively monitor, control, or restore the BES. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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 BES, or the ability to effectively monitor and control the BES; 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 BES, or the ability to effectively monitor, control, or restore the BES.

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 (BPS). In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS

- 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 BAL-003-1.1, Requirement R1
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R1
This justification is provided on the following page.

VRF Justification for BAL-003-1.1, Requirement R2
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R2
The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VRF Justification for BAL-003-1.1, Requirement R3
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R3
The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VRF Justification for BAL-003-1.1, Requirement R4
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R4
The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSLs for BAL-003-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority's (BA)s, or Frequency Response Sharing Group's (FRSG)s, Frequency Response Measure (FRM) was less negative than its Frequency Response Obligation (FRO) by more than 1% but by at most 15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The BA's, or (FRSG)s, FRM was less negative than its FRO by more than 15% but by at most 30% or by more than 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The BA's, or FRSGs, FRM was less negative than its FRO by more than 30% but by at most 45% or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The BA's, or FRSG's, FRM was less negative than its FRO by more than 45% or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.

VSL Justifications for BAL-003-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is not applicable since there was not a requirement mandating a certain level of Frequency Response prior to this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Proposed VSL's are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the amount the calculated FRM is less negative than FRO.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Proposed VSL's do not expand on what is required. The VSL's assigned only consider results of the calculation required. Proposed VSL's are 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	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Frequency Response Standard Background Document

November, 2012

RELIABILITY | ACCOUNTABILITY






3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Introduction

This document provides background on the development, testing and implementation of BAL-003-1 - Frequency Response Standard ("FRS").[1] The intent is to explain the rationale and considerations for the Requirements of this standard and their associated compliance information. The document also provides good practices and tips for Balancing Authorities ("BAs") with regard to Frequency Response.

In Order No. 693, the Federal Energy Regulatory Commission ("FERC" or the "Commission") directed additional changes to BAL-003.[2] This document explains how compliance with those directives are met by BAL-003-1.

The original Standards Authorization Request ("SAR"), finalized on June 30, 2007, assumed there was adequate Frequency Response in all the North American Interconnections. The goal of the SAR was to update the Standard to make the measurement process of frequency response more objective and to provide this objective data to Planners and Operators for improved modeling. The updated models will improve understanding of the trends in Frequency Response to determine if reliability limits are being approached. The Standard would also lay the process groundwork for a transition to a performance-based Standard if reliability limits are approached.

This document will be periodically updated by the FRS Drafting Team ("FRSDT") until the Standard is approved. Once approved, this document will then be maintained and updated by the ERO and the NERC Resources Subcommittee to be used as a reference and training resource.

Background

This section discusses the different components of frequency control and the individual components of Primary Frequency Control also known as Frequency Response.

Frequency Control

Most system operators generally have a good understanding of frequency control and Bias Setting as outlined in the balancing standards and the references to them in the NERC Operating Manual. Frequency control can be divided into four overlapping windows of time as outlined below.

> **Primary Frequency Control (Frequency Response) –** Actions provided by the Interconnection to arrest and stabilize frequency in response to frequency deviations.

[1] Unless otherwise designated herein, all capitalized terms shall have the meaning set forth in the Glossary of Terms Used in NERC Reliability Standards, available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

[2] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 368-375, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Primary Control comes from automatic generator governor response (also known as speed regulation), load response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems.

Secondary Frequency Control – Actions provided by an individual BA or its Reserve Sharing Group to correct the resource – load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary Frequency Response. Secondary Control comes from either manual or automated dispatch from a centralized control system.

Tertiary Frequency Control – Actions provided by Balancing Authorities on a balanced basis that are coordinated so there is a net zero effect on Area Control Error (ACE). Examples of Tertiary Control include dispatching generation to serve native load; economic dispatch; dispatching generation to affect Interchange; and re-dispatching generation. Tertiary Control actions are intended to replace Secondary Control Response by reconfiguring reserves.

Time Control includes small offsets to scheduled frequency to keep long term average frequency at 60 Hz.

Primary Frequency Control – Frequency Response

Primary Frequency Control, also known generally as **Frequency Response**, is the first stage of overall frequency control and is the response of resources and load to a locally sensed change in frequency in order to arrest that change in frequency. Frequency Response is automatic, not driven by any centralized system, and begins within seconds rather than minutes. Different resources, loads, and systems provide Frequency Response with different response times, based on current system conditions such as total resource/load and their respective mix.

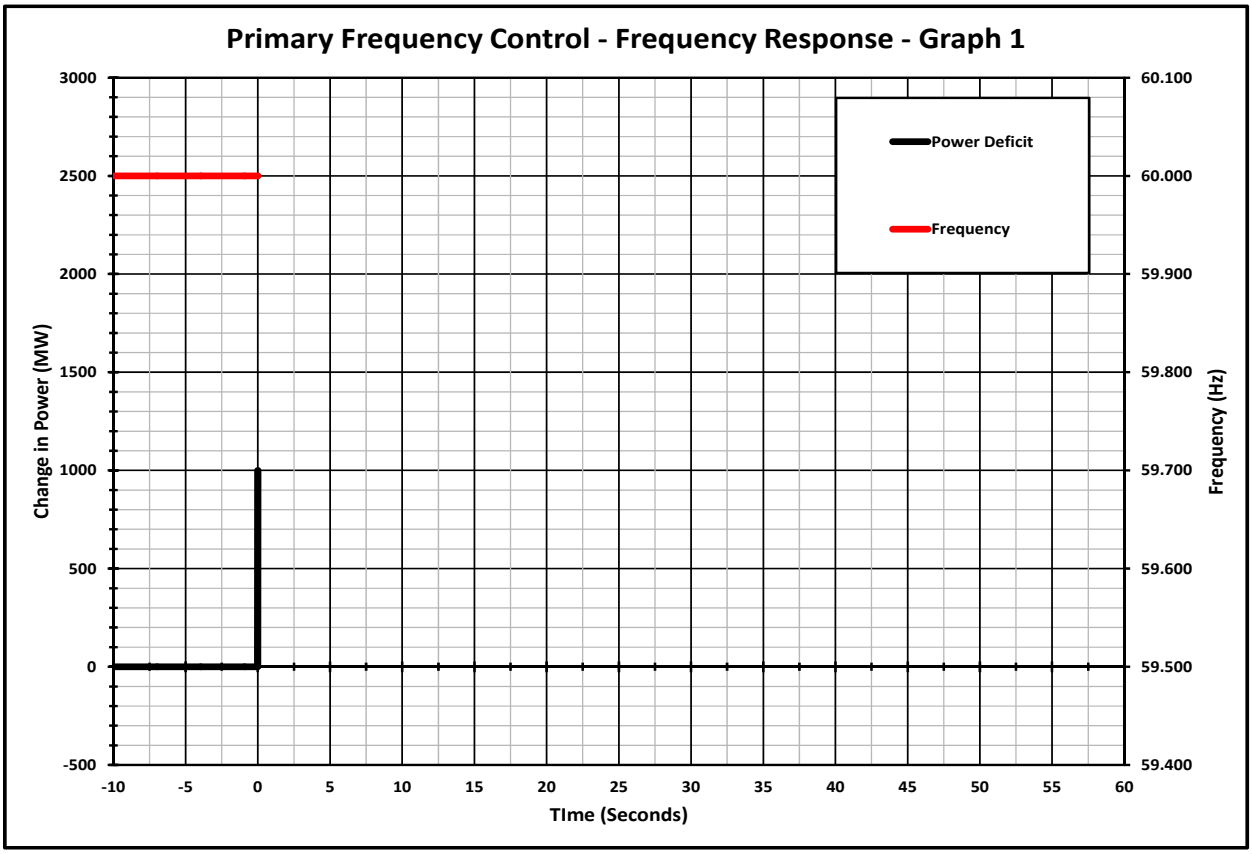
The proposed NERC Glossary of Terms defines **Frequency Response** as:

- (Equipment) The immediate and automatic reaction or response of power from a system or power from elements of the system to a change in locally sensed system frequency.
- (System) The sum of the change in demand, and the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

As noted above, Frequency Response is the characteristic of load and generation within Balancing Authorities and Interconnections. It reacts or responds with changes in power to attempted changes in load-resource balance that result in changes to system frequency. Because the loss of a large generator is much more likely than a sudden loss of an equivalent amount of load, Frequency Response is typically discussed in the context of a loss of a large generator. Included within Frequency Response are many components of that response. Understanding Frequency Response and the FRS requires an understanding of each of these components and how they relate to each other.

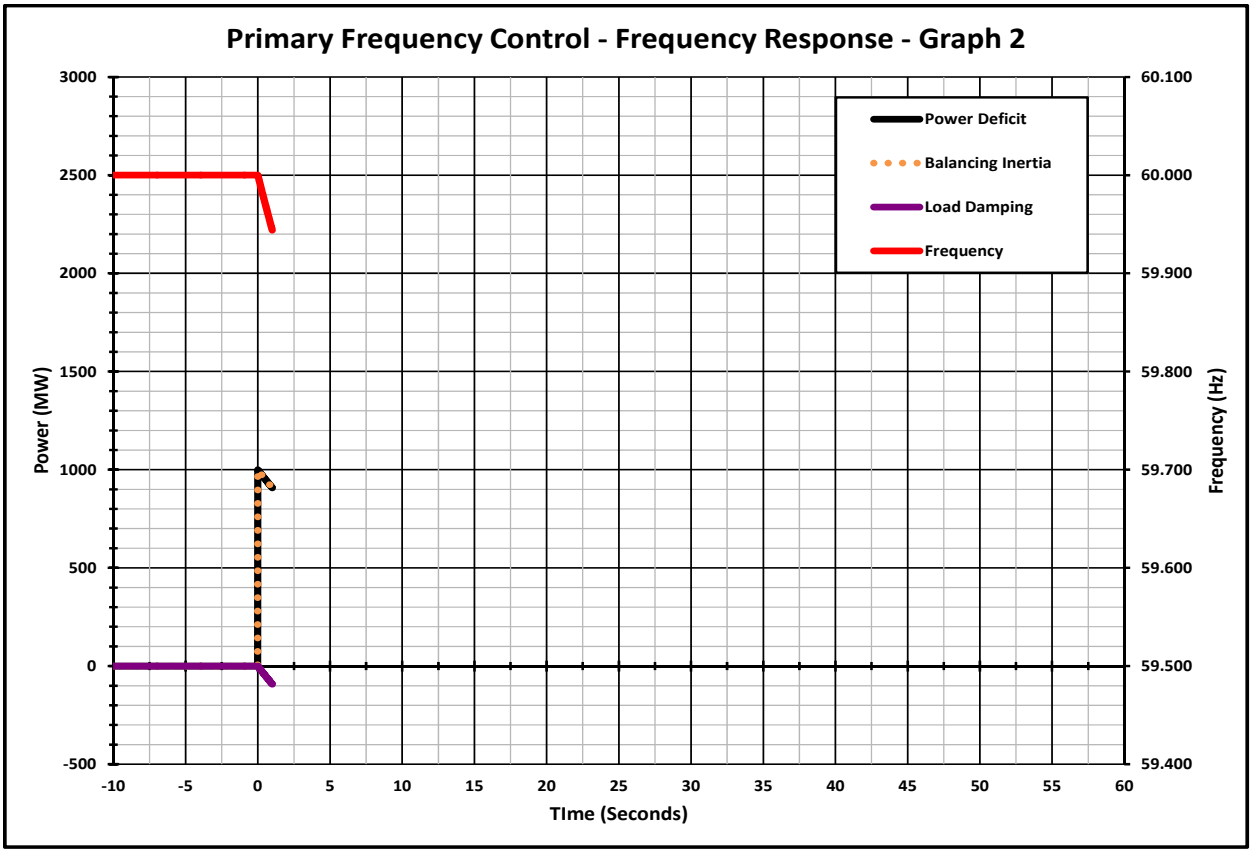
Frequency Response Illustration

The following simple example is presented to illustrate the components of Frequency Response in graphical form. It includes a series of seven graphs that illustrate the various components of Frequency Response and a brief discussion of each describing how these components react to attempted changes in the load-resource balance and resulting changes in system frequency. The illustration is based on an assumed Disturbance event of the sudden loss of 1000 MW of generation. Although a large event is used to illustrate the response components, even small frequently occurring events will result in similar reactions or responses. The magnitude of the event only affects the shape of the curves on the graph; it does not obviate the need for Frequency Response.



The first graph, Primary Frequency Control – Frequency Response – Graph 1, presents a sudden loss of generation of 1000 MW. The components are presented relative to time as shown on the horizontal Time axis in seconds. This simplified example assumes a Disturbance event of the sudden loss of generation resulting from a breaker trip that instantaneously removes 1000 MW of generation from the interconnection. This sudden loss is illustrated by the power deficit line shown in black using the MW scale on the left. Interconnection frequency is illustrated by the frequency line shown in red using the Hertz scale on the right. Since the Scheduled Frequency is normally 60 Hz, it is assumed that this is the frequency when the Disturbance event occurs.

Even though the generation has tripped and power injected by the generator has been removed from the interconnection, the loads continue to use the same amount of power. The "Law of Conservation of Energy"[3] requires that the 1000 MW must be supplied to the interconnection if energy balance is to be "conserved." This additional 1000 MW of power is produced by extracting kinetic energy that was stored in the rotating mass of all of the synchronized generators and motors on the interconnection – essentially using this equipment as a giant flywheel. The extracted energy supplies the "balancing inertia"[4] power required to maintain the power and energy balance on the interconnection. This balancing inertia power is produced by the generators' spinning inertial mass' resistance to the slowdown in speed of the rotating equipment on the interconnection that both provides the stored kinetic energy and reduces the frequency of the interconnection. This is illustrated in the second graph, Primary Frequency Control – Frequency Response – Graph 2, by the orange dots representing the balancing inertia power that exactly overlay and offset the power deficit.



As the frequency decreases, synchronized motors slow, as does the work they are providing, resulting in a decrease in load called "load damping." This load damping is the reason that the power deficit initially declines. Synchronously operated motors will contribute to load

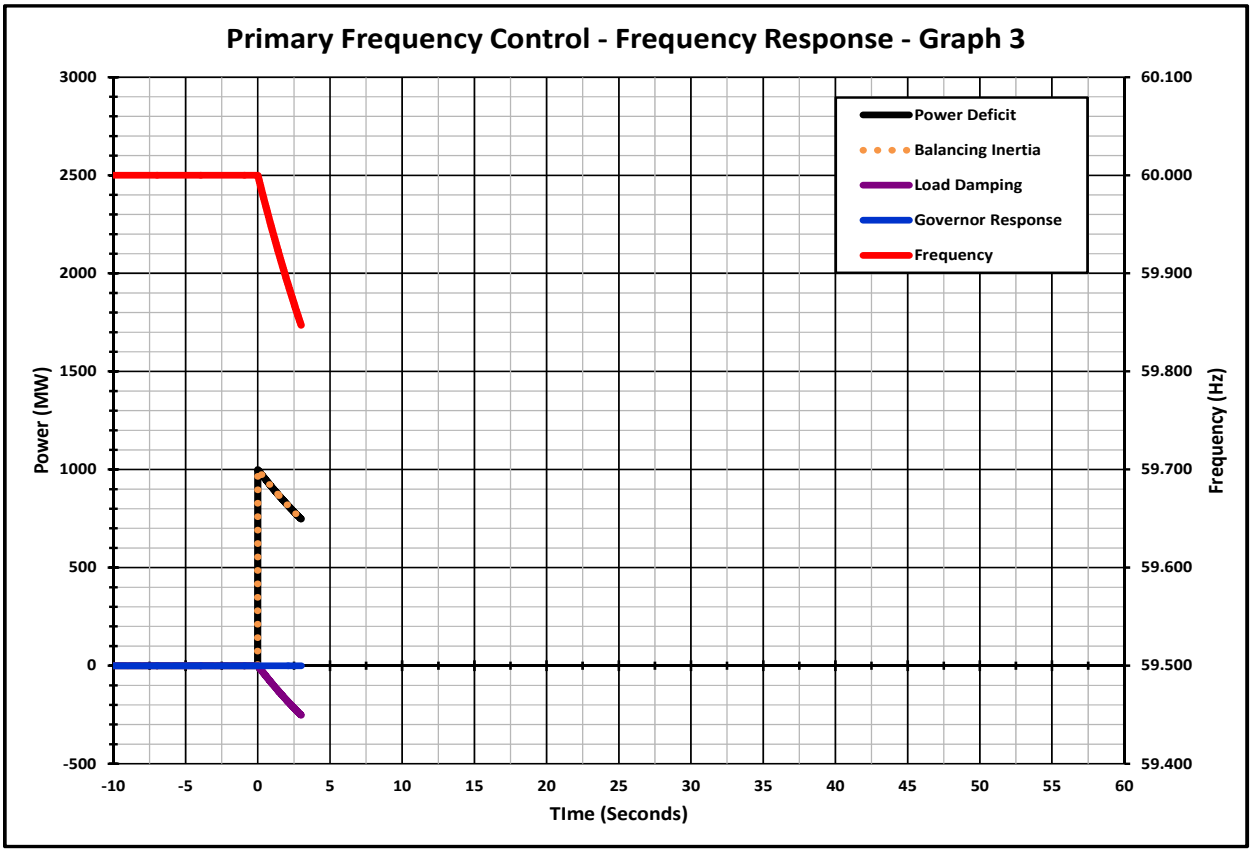
[3] The "Law of Conservation of Energy" is applied here in the form of power. If energy must be conserved, then power which is the first derivative of energy with respect to time, must also be conserved.

[4] The term "balancing Inertia" is coined here from the terms "inertial frequency response" and "balancing energy". Inertial frequency response is a common term used to describe the power supplied for this portion of the frequency response and balancing energy is a term used to describe the market energy supposedly purchased to restore energy balance.

damping. Variable speed drives that are decoupled from the interconnection frequency do not contribute to load damping. In general, any load that does not change with interconnection frequency including resistive load will not contribute to load damping or Frequency Response.

It is important to note that the power deficit equals exactly the balancing inertia, indicating that there is no power or energy imbalance at any time during this process. What is normally considered as "balancing power or energy" is actually power or energy required to correct the frequency error from scheduled frequency. Any apparent power or energy imbalance is corrected instantaneously by the balancing inertia power and energy extracted from the interconnection. Thus the balancing function is really a frequency control function described as a balancing function because ACE is calculated in MWs instead of Hertz, frequency error.

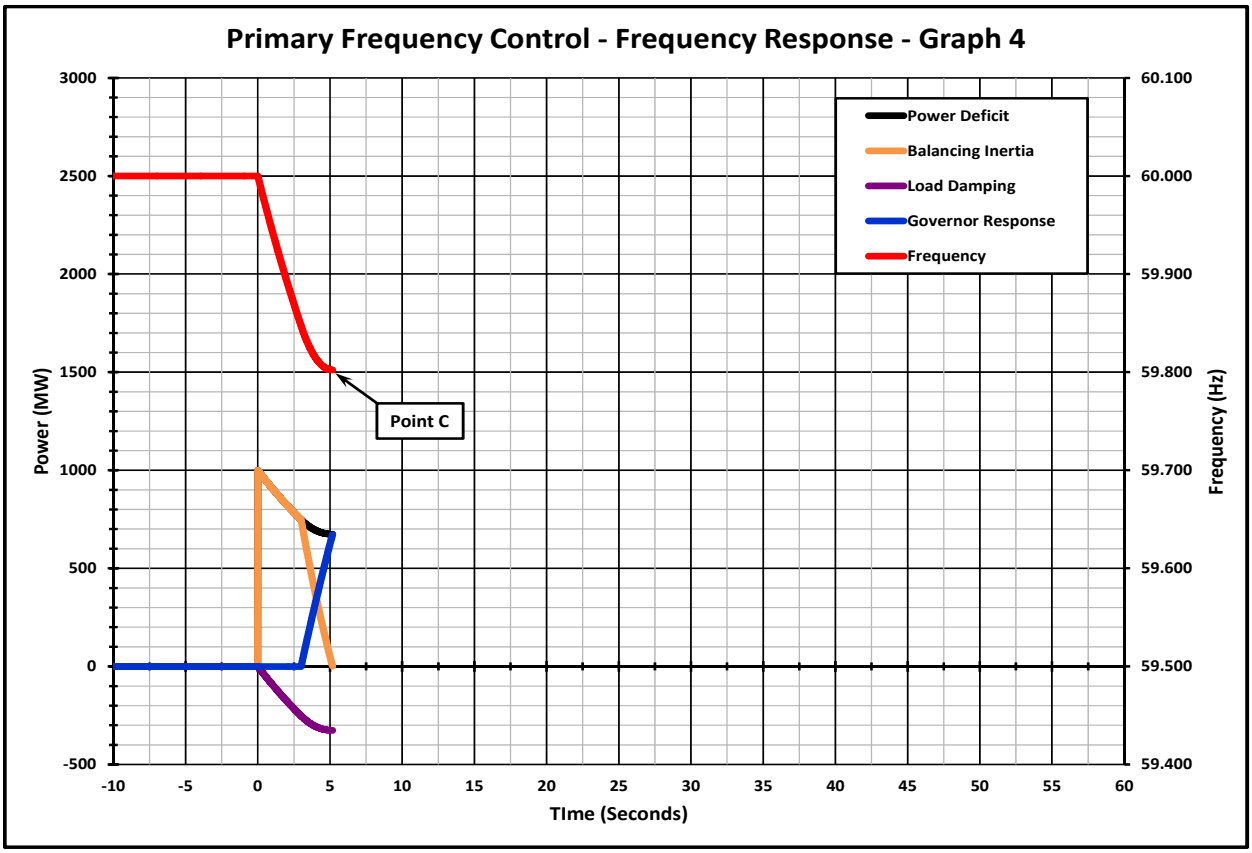
During the initial seconds of the Disturbance event, the governors have yet to respond to the frequency decline. This is illustrated with the Blue line on the third graph, Primary Frequency Control – Frequency Response – Graph 3, showing Governor Response. This time delay results from the time that it takes the controller to adjust the equipment and the time it takes the mass to flow from the source of the energy (main steam control valve for steam turbines, the combustor for gas turbines, or the gate valve for hydro turbines) to the turbine-generator blades where the power is converted to electrical energy.



Note that the frequency continues to decline due to the ongoing extraction by balancing inertia power of energy from the rotating turbine-generators and synchronous motors on the

interconnection. The reduction in load also continues as the effect of load damping continues to reduce the load while frequency declines. During this time delay (before the governor response begins) the balancing inertia limits the rate of change of frequency.

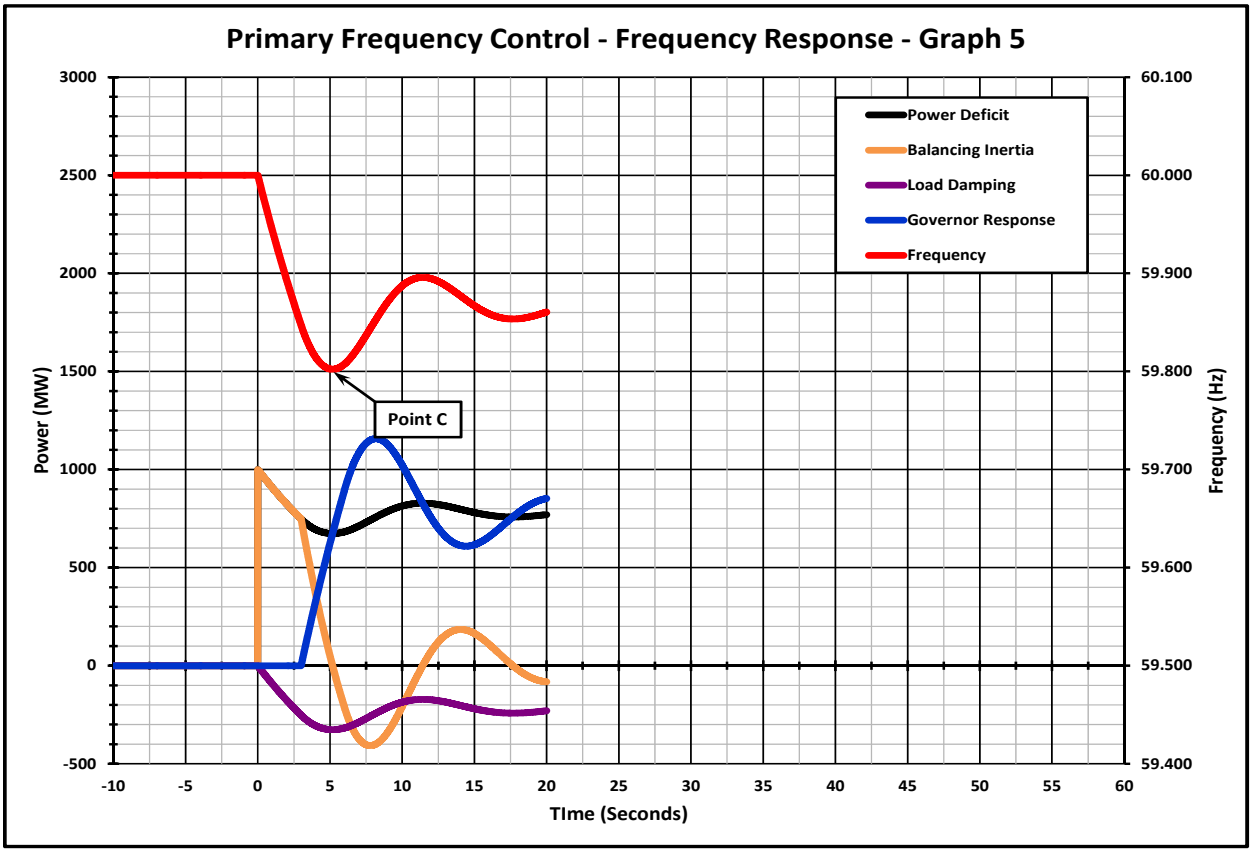
After a short time delay, the governor response begins to increase rapidly in response to the initial rapid decline in frequency, as illustrated on the fourth graph, Primary Frequency Control – Frequency Response – Graph 4. Governor response exactly offsets the power deficit at the point in time that the frequency decline is arrested. At this point in time, the balancing inertia has provided its contribution to reliability and its power contribution is reduced to zero as it is replaced by the governor response. If the time delay associated with the delivery of governor response is reduced, the amount of balancing inertia required to limit the change in frequency by the Disturbance event can also be reduced. This supports the conclusion that balancing inertia is required to manage the time delays associated with the delivery of Frequency Response. Not only is the rapid delivery of Frequency Response important, but the shortening of the time delay associated with its delivery is also important. Therefore, two important components of Frequency Response are 1) how long the time delay is before the initial delivery of response begins; and 2) how much of the response is delivered before the frequency change is arrested.



This point, at which the frequency is first arrested, is defined as "Point C" and Frequency Response calculated at this point is called the "**arrested frequency response**." The arrested

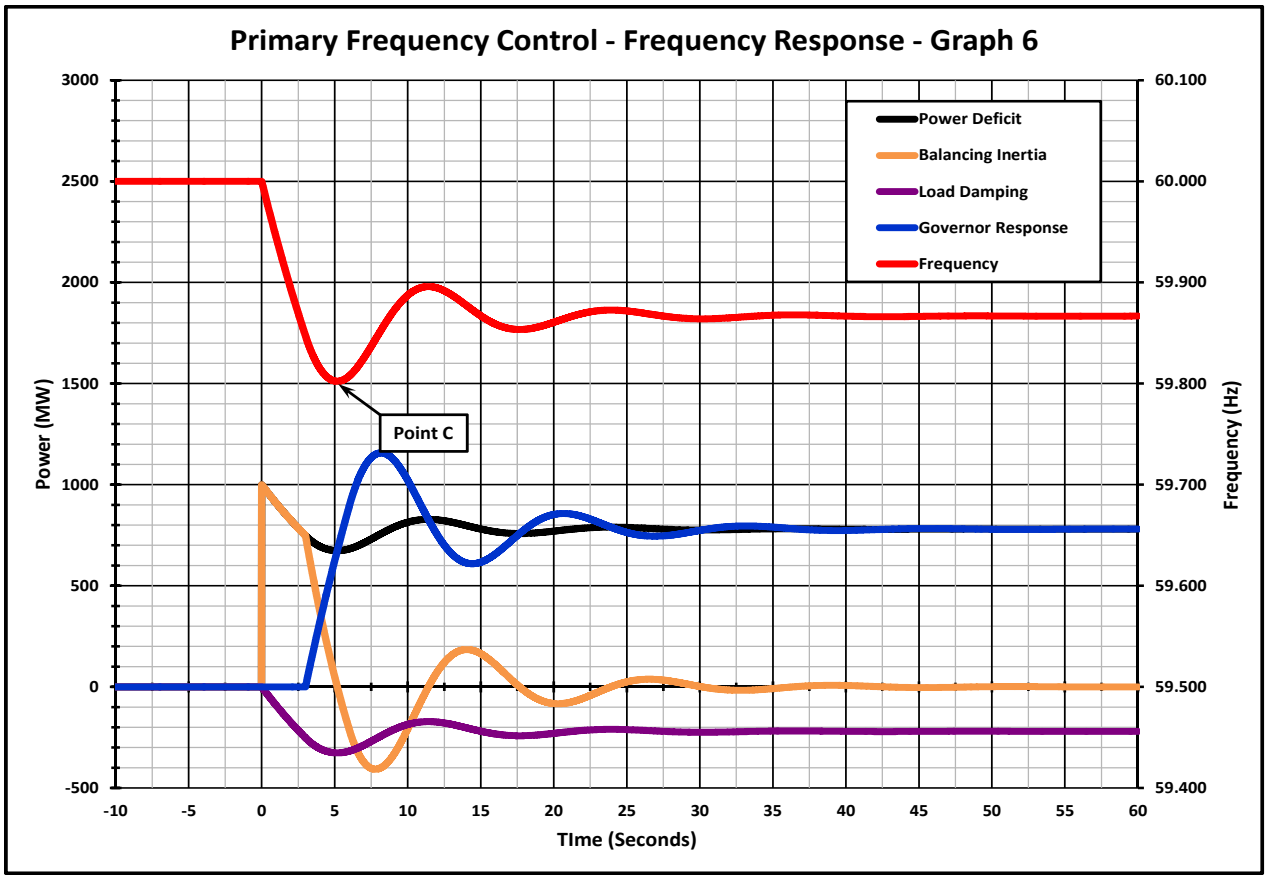
frequency is normally the minimum (maximum for load loss events) frequency that will be experienced during a Disturbance event. From a reliability perspective, this minimum frequency is the frequency that is of concern. Adequate reliability requires that frequency at the time frequency is arrested remain above the under-frequency relay settings so as not to trip these relays and the firm load interrupted by them. Frequency Response delivered after frequency is arrested at this minimum level provides less reliability value than Frequency Response delivered before Point C, but greater value than Secondary Frequency Control power and energy which is delivered minutes later.

Once the frequency decline is arrested, the governors continue to respond because of the time delay associated with their Governor Response. This results in the frequency partially recovering from the minimum arrested value and results in an oscillating transient that follows the minimum frequency (arrested frequency) until power flows and frequency settle during the transient period that ends roughly 20 seconds after the Disturbance event. This post-disturbance transient period is included on the fifth illustrative graph, Primary Frequency Control – Frequency Response – Graph 5.

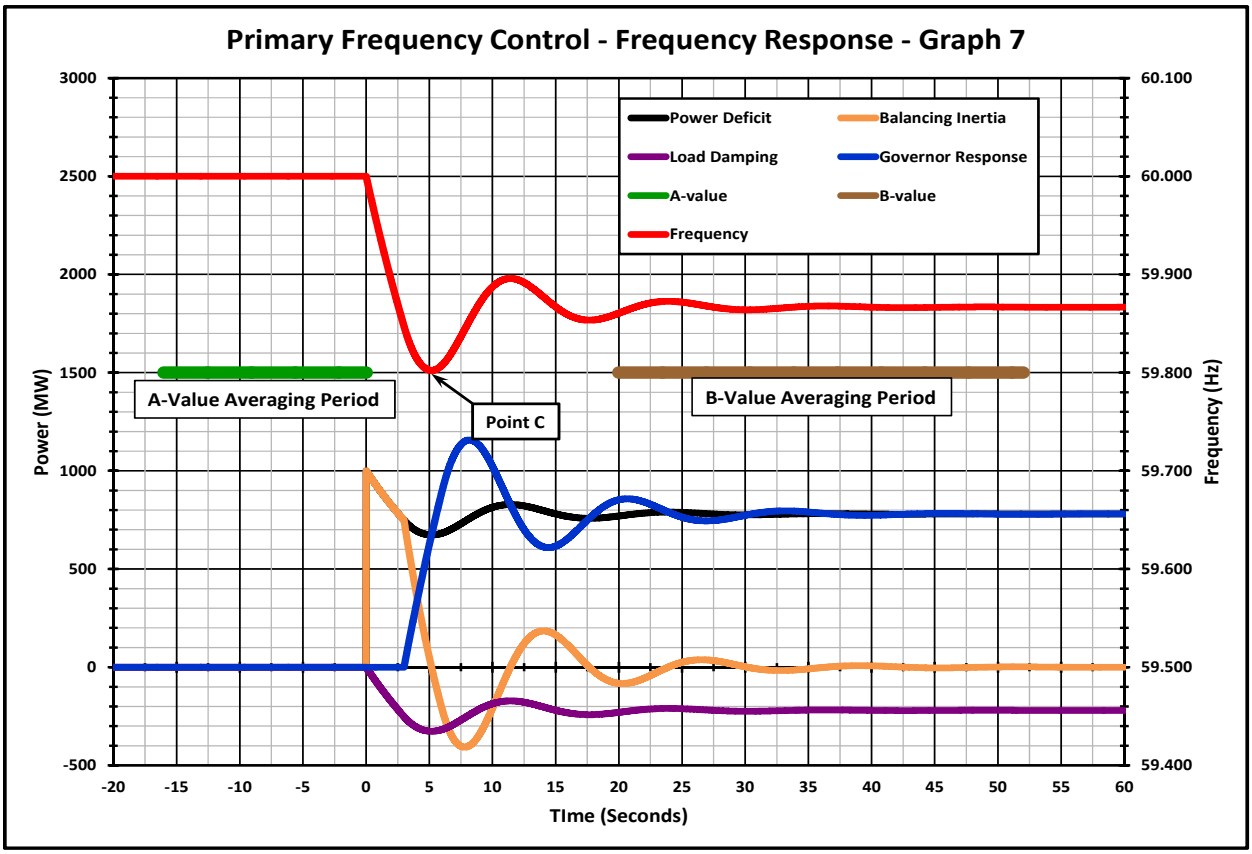


The total Disturbance event illustration is presented on the sixth graph, Primary Frequency Control – Frequency Response – Graph 6. Frequency and power contributions stabilize at the end of the transient period. Frequency Response calculated from data measured during this

settled period is called the “Settled Frequency Response.” The Settled Frequency Response is the best measure to use as an estimator for the “Frequency Bias Setting” discussed later.



The final Disturbance event illustration is presented on the seventh graph, Primary Frequency Control – Frequency Response – Graph 7. This graph shows the averaging periods used to estimate the pre-disturbance A-Value averaging period and the post-disturbance B-Value averaging period used to calculate the settled frequency response. A discussion of the measurement of Frequency Response immediately follows these graphs. That discussion includes consideration of the factors that affect the methods chosen to measure Frequency Response for implementation in a reliability standard.



Frequency Response Measurement (FRM)

The classic Frequency Response points A, C, and B, shown below in Fig. 1 Frequency Response Characteristic, are used for measurement as found in the Frequency Response Characteristic Survey Training Document within the NERC operating manual, found at http://www.nerc.com/files/opman_7-1-11.pdf. This traditional Frequency Response Measure has recently been more specifically termed "**settled frequency response**." This term has been used because it provides the best Frequency Response Measure to estimate the Frequency Bias Setting in Tie-line Bias Control based Automatic Generation Control Systems. However, the industry has recognized that there is considerable variability in measurement resulting from the selection of Point A and Point B in the traditional measure making the traditional measurement method unsuitable as the basis for an enforceable reliability standard in a real world setting of multiple Balancing Authority interconnections.

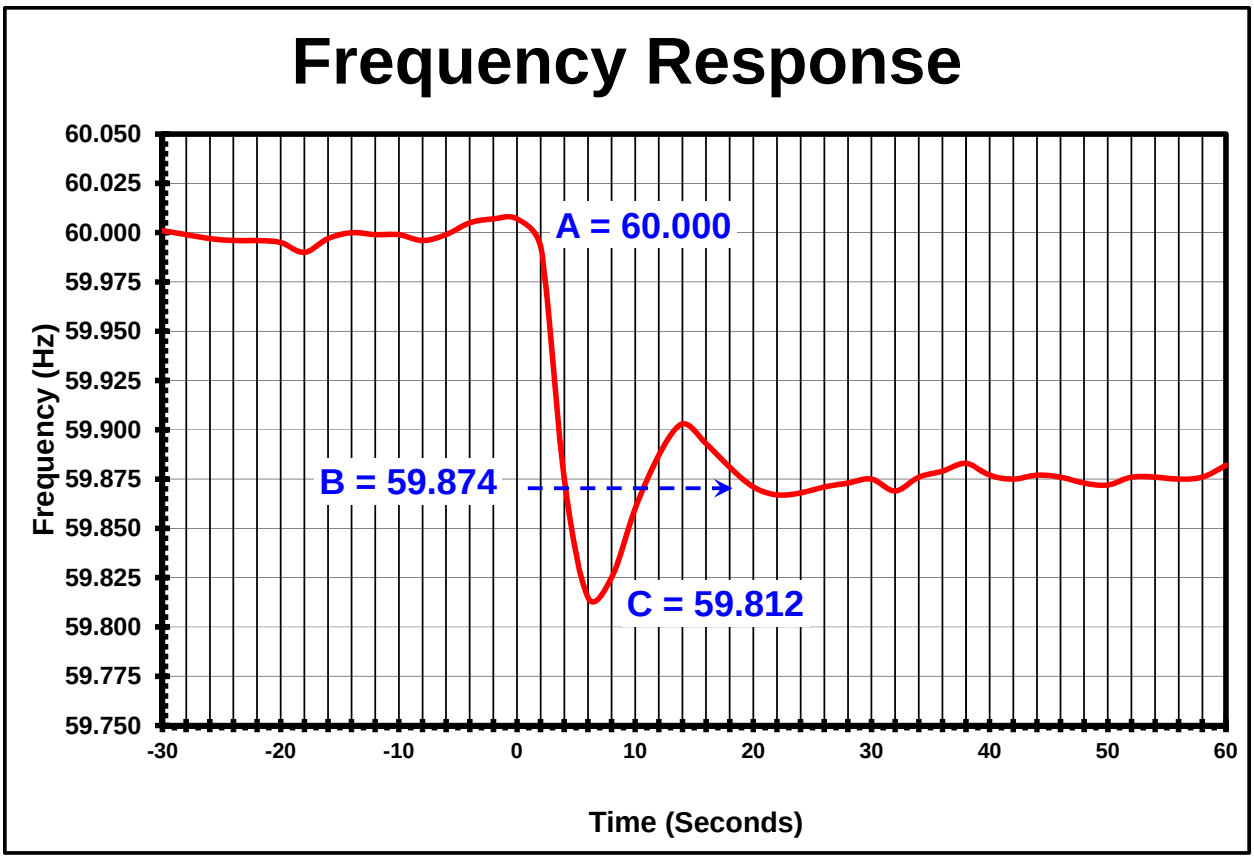


Figure 1. Frequency Response Characteristic

By contrast, measuring an Interconnection's settled frequency response is straightforward and fairly accurate. All that's needed to make the calculation is to know the size of a given contingency (MW), divide this value by the change in frequency and multiply the results by 10 since frequency response is expressed in MW/0.1Hz.

Measuring a BA's frequency response is more challenging. Prior to BAL-003-1, NERC's *Frequency Response Characteristic Survey Training Document* provided guidance to calculate Frequency Response. In short, it told the reader to identify the BA's interchange values "immediately before" and "immediately after" the Disturbance event and use the difference to calculate the MWs the BA deployed for the event. There are two challenges with this approach:

- Two people looking at the same data would come up with different values when assessing which exact points were immediately before and after the event.
- In practice, the actual response provided by the BA can change significantly in the window of time between point B and when secondary and tertiary control can assist in recovery.

Therefore, the measurement of settled frequency response has been standardized in a number of ways to limit the variability in measurement resulting from the poorly specified selection of Point A and Point B. It should be noted that t-0 has been defined as the first scan value that

shows a deviation in frequency of some significance, usually approaching about 10 mHz. The goal is such that the first scan prior to t-0 was unaffected by the deviation and appropriate for one of the averaging points.

- The A-value averaging period of approximately the previous 16 seconds prior to t-0 was selected to allow for an averaging of at least 2 scans for entities utilizing 6 second scan rates. (All time average period references in this document are for 2 second scan rates unless noted otherwise.)
- The B-value averaging period of approximately (t+20 to t+52 seconds) was selected to attempt to obtain the average of the data after primary frequency response was deployed and the transient completed(settled), but before significance influence of secondary control. Multiple periods were considered for averaging the B-value:
    - 12 to 24 sec
    - 18 to 30 sec
    - 20 to 40 sec
    - 18 to 52 sec
    - 20 to 52 sec

  It is necessary for all BAs from an interconnection to use the same averaging periods to provide consistent results. In addition, the SDT decided that until more experience is gained, it is also desirable for all interconnections to use the same averaging periods to allow comparison between interconnections.

The methods presented in this document only address the values required to calculate the frequency response associated with the frequency change between the initial frequency, A-Value, and the settling frequency, B-Value. No reasonable or consistent calculations can be made relating to the arresting frequency, C-Value, using Energy Management System (EMS) scan rate data as long as 6-seconds or tie-line flow values associated with the minimum value of the frequency response characteristic (C-value) as measured at the BA level.

Both the calculation of the frequency at Point A and the frequency at Point B began with the assumption that a 6-second scan rate was the source of the data. Once the averaging periods for a 6-second scan rate were selected, the averaging periods for the other scan rates were selected to provide as much consistency as possible between BAs with different scan rates.

The Frequency at Point A was initially defined as the average of the two scans immediately prior to the frequency event. All other averaging periods were selected to be as consistent as possible with this 12 second average scan from the 6-second scan rate method. In addition, the "**actual net interchange immediately before Disturbance**" is defined as the average of the same scans as used for the Point A frequency average.

The Frequency at Point B was then selected to be an average as long as the average of 6-second scan data as possible that would not begin until most of the hydro governor response had been delivered and would end before significant Automatic Generation Control (AGC) recovery response had been initiated as indicated by a consistent frequency restoration slope. The "**actual net interchange immediately after Disturbance**" is defined as the average of the same scans as used for the Point B frequency average.

B Averaging Period Selection:

Experience from the Electric Reliability Council of Texas ("ERCOT") and the field trail on other interconnections indicated that the 12 to 24 second and 18 to 30 second averaging periods were not suitable because they did not provide the consistency in results that the other averaging periods provided, and that the remaining measuring periods do not provide significantly different results from each other. The team believed that this was observed because the transients were not complete in all of the samples using these averaging periods.

The 18 to 52 second and 20 to 52 second averaging periods were compared to each other, with the 20 to 52 second period providing more consistent values, believed to result from the incomplete transient in some of the 18 to 52 second samples.

This left a choice between the 20 to 40 second and the 20 to 52 second averaging periods. The team recognized that there would be more AGC response in the 20 to 52 second period, but the team also recognized that the 20 to 52 second period would provide a better measure of squelched response from outer loop control action. The 20 to 52 second period was selected because it would indicate squelched response from outer-loop control and provide incentive to reduce response withdrawal. The final selections for the data averaging periods used in FRS Form 1 are shown in the table below.

Definitions of Frequency Values for Frequency Response Calculation

Scan Rate	T 0 Scan	A Value (average)	B Value (average)
6-Seconds	Identify first significant change in frequency as the T 0 scan	Average of T-1 through T-2 scans	Average of T+4 through T+8 scans
5-Seconds		Average of T-1 through T-2 scans	Average of T+5 through T+10 scans
4-Seconds		Average of T-1 through T-3 scans	Average of T+6 through T+12 scans
3-Seconds		Average of T-1 through T-5 scans	Average of T+7 through T+17 scans
2-Seconds		Average of T-1 through T-8 scans	Average of T+10 through T+26 scans

Consistent measurement of Primary Frequency Response is achievable for a selected number of events and can produce representative frequency response values, provided an appropriate sample size is used in the analysis. Available research investigating the minimum sample size to provide consistent measurements of Frequency Response has shown that a minimum sample size of 20 events should be adequate.

Measurement of Primary Frequency Response on an individual resource or load basis requires analysis of energy amounts that are often small and difficult to measure using current methods. In addition, the number of an interconnection's resources and loads providing their response could be problematic when compiling results for multiple events.

Measurement of Primary Frequency Response on an interconnection (System) basis is straight forward provided that an accurate frequency metering source is available and the magnitude of the resource/load imbalance is known in MWs.

Measurement on a Balancing Authority basis can be a challenge, since the determination of change in MWs is determined by the change in the individual BA's metered tie lines. Summation of tie lines is accomplished by summing the results of values obtained by the digital scanning of meters at intervals up to six seconds, resulting in a non-coincidental summing of values. Until the technology to GPS time stamp tie line values at the meter and the summing of those values for coincidental times is in use throughout the industry, it is necessary to use averaging of values described above to obtain consistent results.

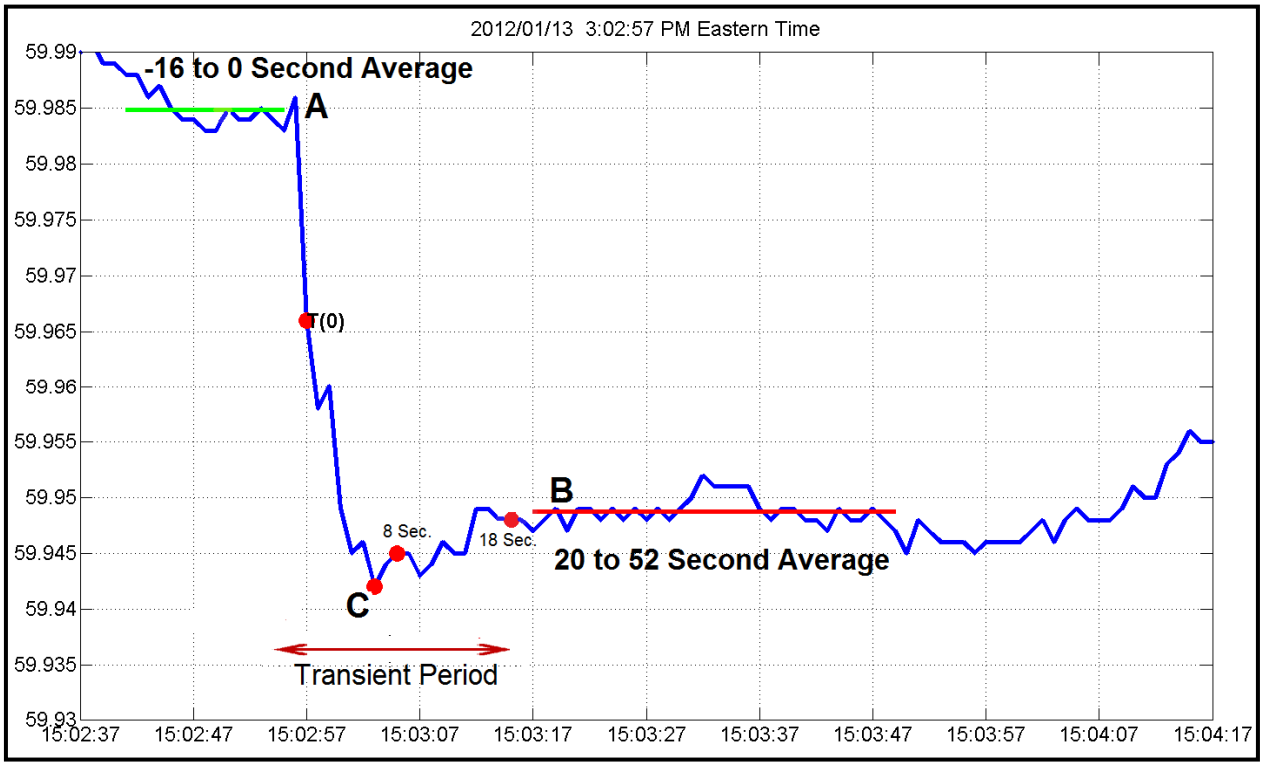


Figure 2. Frequency Response Measurement

The standardized measure is shown graphically in Fig. 2 Frequency Response Measurement with the averaging periods shown by the solid green and red lines on the graph. Since FERC directed a performance obligation for BAL-003-1, it is important to be more objective in the measurement process. The standardized calculation is available on FRS Form 2 for EMS scan rates of 2, 3, 4, 5, and 6 seconds at http://www.nerc.com/filez/standards/Frequency_Response.html.

Arrested Frequency Response

There is another measure of Frequency Response that is of interest when developing a Frequency Response estimate that not only will be used for estimating the Frequency Bias Setting, but will also be used to assure reliability by operating in a manner that will bound interconnection frequency and prevent the operation of Under-frequency Relays. This Frequency Response Measure has recently been named "**arrested frequency response.**" This Frequency Response is significantly affected by the inertial Frequency Response, the governor Frequency Response and the time delays associated with the delivery of governor Frequency

Response. It is calculated by using the change in frequency between the initial frequency, A, and the maximum frequency change during the event, C, instead of using the change between A and B. Arrested Frequency Response is the correct response for determining the minimum Frequency Response related to under-frequency relay operation and the support of interconnection reliability. This is because it can be used to provide a direct estimate of the maximum frequency deviation an interconnection will experience for an initial frequency and a given size event in MW. Unfortunately, arrested frequency response cannot currently be measured using the existing EMS-based measurement infrastructure. This limitation exists because the scan rates currently used in industry EMSs are incapable of measuring the net actual interchange at the same instant that the maximum frequency deviation is reached. Fortunately, the ratio of arrested frequency response and settled frequency response tends to be stable on an interconnection. This allows the settled frequency response value to be used as a surrogate for the arrested frequency response and implement a reasonable measure upon which to base a standard. One consequence of using the settled frequency response as a surrogate for the arrested frequency response is the inclusion of a large reliability margin in Interconnection Frequency Response Obligation to allow for the difference between the settled frequency response as measured and the arrested frequency response that indicates reliability.

As measurement infrastructure improves one might expect the Frequency Response Obligation to transition to a measurement based directly on the arrested frequency response while the Frequency Bias Setting will continue to be based on the settled frequency response. However, at this time, the measurement devices and methods in use do not support the necessary level of accuracy to estimate arrested frequency response contribution for an individual Balancing Authority.

Frequency Response Definition and Examples

Limitations of the measurement infrastructure determine the measurement methods recommended in this standard. The measurement limitations provide opportunities to improve the Frequency Response as measured in the standard without contributing to an improvement in Frequency Response that contributes to reliability. These definitions and examples provide a basis for determining which contributions to Frequency Response contribute the most to improved reliability. They also provide the basis for determining on a case by case basis whether the individual contributors to the Frequency Response Measure are also contributing to reliability.

General Frequency Response Characteristics

In the simplest case Frequency Response includes any automatic response to changes in local frequency. If that response works to decrease that change in frequency, it is beneficial to reliability. If that response works to increase that change in frequency, it is detrimental to reliability. However, this definition does not address the relative value of one response as compared to other responses that may be provided in a specific case.

There are numerous characteristics associated with the Frequency Response that affect the reliability value and economic value of the response. These characteristics include:

1. **Inertial** – the response is inertial or approximates inertial response

Inertial response provides power without delay that is proportional to the frequency and the change in frequency. Therefore, power provided by electronic control as synthetic Inertial response must be proportional to the frequency and change in frequency and be provided without a time delay.

2. **Immediate** – no unnecessary intentional time delays or reduction in the rate of response delivery
    a. time delay before the beginning of the response
    Turbines that convert heat or kinetic energy have time delays related to the time delay from the time that the control valves are moved to initiate the change in power and the time that the power is delivered to the generator. These times are usually associated with the time it takes a change in mass flow to travel from the control valve to the first blades of the turbine in the turbine generator.

    b. reduction in the rate of response delivery
    There are natural delays associated with the rate of response delivery that are related to the mass flow travel from the first turbine blades to the last turbine blades. In addition, some turbines have intentional delays designed into the control system to slow the rate of change in the delivery of the kinetic energy or fuel to the turbine to prevent the turbine or other equipment from being damaged, hydro turbines, or to prevent the turbine from tripping due to excessive rate of change, gas turbines.

3. **Proportional** – the amount of the total response is proportional to the frequency error
    a. No Deadband – the response is proportional across the entire frequency range
    b. Deadband – the response is only proportional outside of a defined deadband

4. **Bi-directional** – the response occurs to both increases and decreases in frequency

5. **Continuous** – there are no discontinuities in the delivery of the response (no step changes)

6. **Sustained** – the response is sustained until frequency is returned to schedule

Frequency Response Reliability Value

This section contains a more detailed discussion of the various characteristics of Frequency Response listed in the previous section. It also provides an indication of the relative value of these characteristics with respect to their contribution to reliability. Finally, it includes some examples of the described responses.

Inertial Response is provided from the stored energy in the rotating mass of the turbine-generators and synchronous motors on the interconnection. It limits the rate of change of frequency until sufficient Frequency Response can be supplied to arrest the change in frequency. Its reliability value increases as the time delay associated with the delivery of other Frequency Response on the interconnection increases. If those time delays are minimal, then the value of inertial response is low. If all time delays associated with the Frequency Response could be eliminated, then inertial response would have little value.

The reliability value of Inertial Response is the greatest on small interconnections because the size of the Disturbance events is larger relative to the inertia of the interconnection. Electronic controls have been developed to provide synthetic inertial response from the stored energy in asynchronous generators to supplement the natural inertial response. Some Type III & IV Wind Turbines have this capability. In addition, electronically controlled SCRs have been developed that can store energy in the electrical system and release this stored energy to supply synthetic inertial response when required.

Immediate Response is provided by load damping and because the time delays associated with its delivery are very short (related to the speed of electrical signal in the electrical system); load damping requires very little inertial response to limit arrested frequency effectively. Synthetic immediate response can also be supplied from loads because in many cases, there is no mass flow time delay associated with the load process providing the power and energy reduction. Therefore, loads can provide an immediate response with a higher reliability value than generators with time delays required by the physics of the turbine-generator.

Governor response has time delays associated with its delivery. Governor response provided with shorter time delays has a higher reliability value because those shorter time delays require less inertial response to arrest frequency. Governor response is provided by the turbine-generators on the interconnection. Time delays associated with governor response vary depending on the type of turbine-generator providing the response.

The longest time delays are usually associated with high head hydro turbine-generators that require long times from the governor action until the additional mass flow through the turbine. These units may also have the longest delivery time associated with the full delivery of response because of the timing designed into the governor response.[5]

Intermediate time delays are usually associated with steam turbine-generators. The response begins when the steam control valves are adjusted and the steam mass flows from the valves to the first high pressure turbine blades. The delivery times associated with the full delivery of response may require the steam to flow through high, intermediate and low pressure turbines including reheat flows before full power is delivered. These times are shorter than those of the hydro turbine-generators in general, but not as fast as the times associated with gas turbines.[6]

Gas turbines typically have the shortest time delays, because control is provided by injecting more or less fuel into the turbine combustor and adjusting the air control dampers. These control changes can be initiated rapidly and the mass flow has the shortest path to the turbine

[5] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-6 – 1-9.

[6] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-4 – 1-6.

blades. There may be timing limitations related to the rate of change in output of the gas turbine-generator to maintain flame stability in some cases slowing the rate of change.[7]

Synthetic Governor Response can be supplied by certain loads and storage systems. The immediacy of the response is normally limited only by the electronic controls used to activate the desired response. Synthetic response, when it can be supplied immediately without significant time delay, has a higher reliability value because it requires less inertial response to achieve smaller arrested frequency deviations.

Proportional Response indicates that the response provided is proportional in magnitude to the frequency error. Response deadbands cause a non-proportional response and reduce the value of the response with respect to reliability. Contrary to general consensus, deadbands do not reduce the amount of Frequency Response that must be provided, they only transfer the responsibility for providing that Frequency Response from one source on the interconnection to another. For a given response, the response with the smaller deadband has the greater reliability value. Therefore, deadbands should be set to the smallest value that supports overall reliable operation including the reliable operation of the generator.

Electronic controls have also been developed to provide synthetic governor response. When these controls are applied to certain loads or stored energy systems, they can be programmed to provide synthetic governor response similar to the proportional response of a turbine-generator governor. Governor response in generators is limited to a small percentage of the output of the generating unit, while synthetic governor response could be applied to much larger percentages of loads or storage devices providing such response.

Load damping provides a proportional response.

Continuous Response is response that has no discontinuous (step) changes in the frequency versus response curve. Step changes (Non-continuous Response) in the Governor Response curve can lead to frequency instabilities at frequencies near the changes. The ERCOT Interconnection observed this and has since prohibited the use of governor response characteristics incorporating step responses.

Step responses also occur with the implementation of load interruption using under-frequency or over-frequency relays.

Bi-directional Response is response that occurs in both directions, when the frequency is increasing and when the frequency is decreasing. A uni-directional response is a response that only occurs once when frequency is decreasing or when frequency is increasing.

Inertial response, governor response and load damping are all bi-directional responses. Certain loads are capable of providing proportional bi-directional response while others are only capable of providing non-proportional bi-directional response.

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[7] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-16 – 1-19.

The ERCOT Load Resource program is a uni-directional response program. Loads are only tripped when frequency declines below a given set-point. When frequency is restored above that set-point, the loads must be manually reconnected. As a consequence, the Frequency Response only occurs once with declining frequency and does not oppose the increase in frequency after the initial decline. If there should be a frequency oscillation, the uni-directional response will not contribute to the opposition of a second frequency decline across the set-point during an oscillation event. Once a uni-directional response has occurred, it is unavailable for a second decline before reset.

Step or proportional responses implemented bi-directionally can lead to frequency instability when there is less continuous frequency response than the magnitude of the change in continuous response between the trip and reset frequencies in step, or the proportional response rate of change is greater than the underlying continuous response. A step bi-directional response will have the load reconnected as frequency recovers from the event thus opposing the increase in frequency during recovery, and also resetting the load response for the next frequency decline automatically. Bi-directional response obviously has a greater reliability value than uni-directional response.

Sustained Response is provided at its full value until frequency is restored to its scheduled value. On today's interconnections, few frequency responses are fully sustained until frequency has been restored to its scheduled value. On steam based turbine-generators, the steam pressure may drop after a time as the result of the additional steam flow from governor action. However, in general this has not been a problem because most responses are incomplete at the time that frequency has been initially arrested and the additional response has generally been sufficient to make up for more than the these unpreventable reductions in response. However, the intentional withdrawal of response before frequency has been restored to schedule can cause a decline in frequency beyond that which would be otherwise expected. This intentional withdrawal of response is highly detrimental to reliability. Therefore, it can be concluded in general that sustained response has a higher reliability value than un-sustained response.

On an interconnection, the withdrawal of response due to the loss of steam pressure on the steam units may be offset by the slower response of hydro turbine-generators. In these cases, the reliability of the combined response provides a greater reliability value than the individual response of each type. The steam turbine-generators provide a fast response that may be reduced, while the hydro turbine-generators provide a slower response, contributing less to the arresting response, offsetting any reduction by the steam turbine-generators to assure a sustained response.

Sustained Response must also be considered for any resource that has a limited duration associated with its response. The amount of stored energy available from a resource may limit its ability to sustain response for a duration of time necessary to support reliability.

Frequency Response Cost Factors

In every system of exchange there are two sides; the supply side and the demand side. The supply side provides the services used by the demand side. In the case of Frequency Response,

the supply side includes all providers of Frequency Response and the demand side includes all participants that create the need for Frequency Response.

Frequency Response Costs – Supply Side

There are a number of factors that affect the cost of providing Frequency Response from resources. Since there is a cost associated with those factors, some method of appropriate compensation could be made available to those resources providing Frequency Response. Without compensation, providers of Frequency Response will be put in the position of incurring additional cost that can be avoided only by reducing or eliminating the response they provide. These costs are incurred independently of whether provided for in a formal Regional Transmission Organization/Independent System Operator (RTO/ISO) market or in a traditional BA subject to the FERC pro-forma tariffs.

It is the responsibility of the BA or the RTO/ISO to acquire the necessary amount of Frequency Response to support reliability in the most cost effective manner. This function is performed best when the suppliers are evaluated based on the value of the Frequency Response they provide and compensated appropriately for that Frequency Response. Suppliers provide Frequency Response when they are assured that they will receive fair compensation. Before considering how to perform this evaluation and compensation, the costs associated with providing Frequency Response should be understood and evaluated with respect to the level of reliability they offer.

Some cost factors that have been identified for providing Frequency Response include:

1. **Capacity Opportunity Cost** – the costs, including opportunity costs, associated with reserving capacity to provide Frequency Response. These costs are usually associated with the alternative use of the same capacity to provide energy or other ancillary services. There may also be capacity opportunity costs associated with the loss in average capacity by a load providing Frequency Response.
2. **Fuel Cost** – The cost of fuel used to provide the Frequency Response. The costs for fuel to provide Frequency Response can result in energy costs significantly different from the system marginal energy cost, both higher and lower. This is the case when Frequency Response is provided by resources that are not at the system marginal cost.
3. **Energy Efficiency Penalty Costs** – the costs associated with the loss in efficiency when the resource is operated in a mode that supports the delivery of Frequency Response. This cost is usually in the form of additional fuel use to provide the same amount of energy. An example is the difference between operating a steam turbine in valve control mode with an active governor and sliding pressure mode with valves wide open and no active governor control except for over-speed. This cost is incurred for all of the energy provided by the resource, not just the energy provided for Frequency Response. There may be additional energy costs associated with a load providing Frequency Response from loss in efficiency of their process when load is reduced.
4. **Capacity Efficiency Penalty Costs** – the costs associated with any reduction in capacity resulting from the loss of capacity associated with the loss in energy efficiency. When efficiency is lost, capacity may be lost at the same time because of limitations in the amount of input energy that can be provided to the resource.

5. **Maintenance Costs** – the operation of the resource in a manner necessary to provide Frequency Response may result in increases in the maintenance costs associated with the resource.
6. **Emissions Costs** – the additional costs incurred to manage any additional emissions that result when the resource is providing Frequency Response or stands ready to provide Frequency Response.

A good contract for the acquisition of Frequency Response from a resource will provide appropriate compensation to the resource for all of the costs the resource incurs to provide Frequency Response. It will also provide a method to evaluate the least cost mix of resources necessary to provide the minimum required Frequency Response for maintaining reliability. Finally, it will provide the least complex method of evaluation considering the complexity and efficiency of the acquisition process.

Frequency Response Costs – Demand Side

Not only are there costs associated with acquiring Frequency Response from the supplying resources, there are costs associated with the amount of Frequency Response that must be acquired and influenced by those participants that create the need for Frequency Response. If the costs of acquiring Frequency Response from the supply resources can be assigned to those parties that create the need for Frequency Response, there is the promise that the amount of Frequency Response required to maintain reliability can be minimized. The considerations are the same as those that are driving the development of "real time pricing" and "dynamic pricing". If the costs are passed on to those contributing to the need for Frequency Response, incentives are created to reduce the need for Frequency Response making interconnection operations less expensive and more reliable. The problem is to balance both cost and complexity against reliability on both the supply side and the demand side.

Rationale by Requirement

Requirement 1

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 Balancing Authority that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.

Background and Rationale

R1 is intended to meet the following primary objectives:

- Determine whether a Balancing Authority (BA) has sufficient Frequency Response for reliable operations.
- Provide the feeder information needed to calculate CPS limits and Frequency Bias Settings.

Primary Objective

With regard to the first objective, FRS Form 1 and the process in Attachment A provide the method for determining the Interconnections' necessary amount of Frequency Response and allocating it to the Balancing Authorities. The field trial for BAL-003-1 is testing an allocation methodology based on the amount of load and generation in the BA. This is to accommodate the wide spectrum of BAs from generation-only all the way to load-only.

Frequency Response Sharing Groups (FRSGs)

This standard proposes an entity called FRSG, which is defined as:

> *A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.*

This standard allows Balancing Authorities to cooperatively form FRSGs as a means to jointly meet the FRS. There is no obligation to form or be a part of FRSGs. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of FERC's Order No. 693 directives.

FRSG performance may be calculated 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 sums each participant's individual event performance.

Frequency Response Obligation and Calculation

The basic Frequency Response Obligation is based on annual load and generation data reported in FERC Form 714 (where applicable, see below for non-jurisdictional entities) for the previous full calendar year. The basic allocation formula used by NERC is:

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

Where:

- Annual $\mathrm{Gen_{BA}}$ is the annual "Net Generation (MWh)", FERC Form 714, line 13, column c of Part II - Schedule 3.
- Annual $\mathrm{Load_{BA}}$ is the annual "Net Energy for Load (MWh)", FERC Form 714, line 13, column e of Part II - Schedule 3.
- Annual $\mathrm{Gen_{Int}}$ is the sum of all Annual $\mathrm{Gen_{BA}}$ values reported in that interconnection.
- Annual $\mathrm{Load_{Int}}$ is the sum of all Annual $\mathrm{Load_{BA}}$ values reported in that interconnection.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data. Until the BAL-003-1 process outlined in Attachment 1 is implemented, Balancing Authorities can approximate their FRO by multiplying their Interconnection's FRO by their share of Interconnection Bias. The data used for this calculation should be for 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 merge or that transfer load or generation need to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation for the Interconnection remains the same and so that CPS limits can be adjusted.

Attachment A proposes the following Interconnection event criteria as a basis to determine an Interconnection's Frequency Response Obligation:

- Largest category C loss-of-resource (N-2) event.
- Largest total generating plant with common voltage switchyard.
- Largest loss of generation in the interconnection in the last 10 years.

With regard to the second objective above (determining Frequency Bias Settings and CPS limits), Balancing Authorities have been asked to perform annual reviews of their Frequency Bias Settings by measuring their Frequency Response, dating back to Policy 1. This obligation was carried forward into BAL-003-01.b. While the associated training document provided useful information, it left many of the details to the judgment of the person doing the analysis. The FRS Form 1 and FRS Form 2 provide a consistent, objective process for calculating Frequency Response to develop an annual measure, the FRM.

The FRM will be computed 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". The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change of 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 values to account for factors such as nonconforming loads. FRS Form 1 shows the types of adjustments that are allowed.)

A standardized sampling interval of approximately 20 to 52 seconds will be used in the computation of SEFRD values. Microsoft Excel® spreadsheet interfaces for EMS scan rates of 2 through 6 seconds are provided to support the computation.

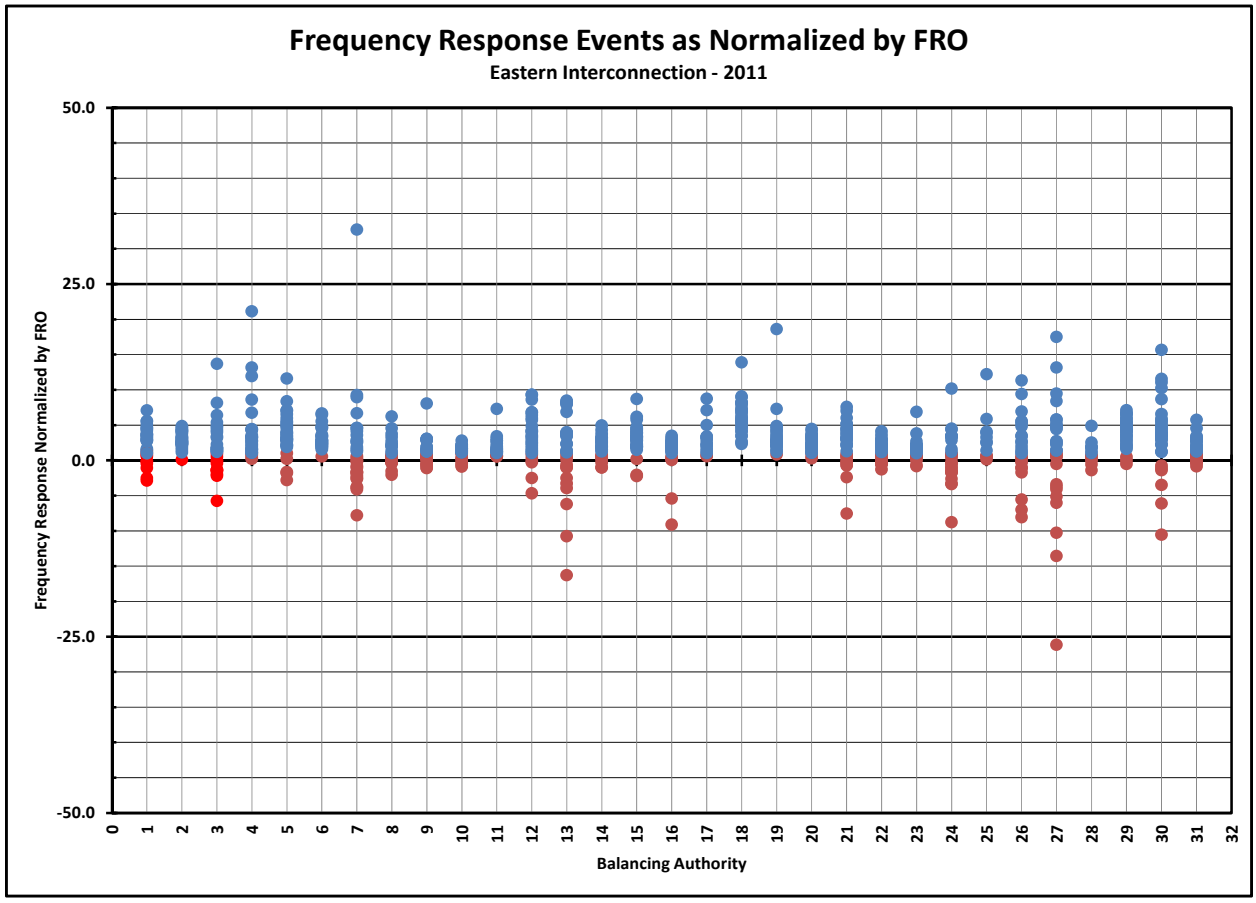
Single Event Frequency Response Data[8]

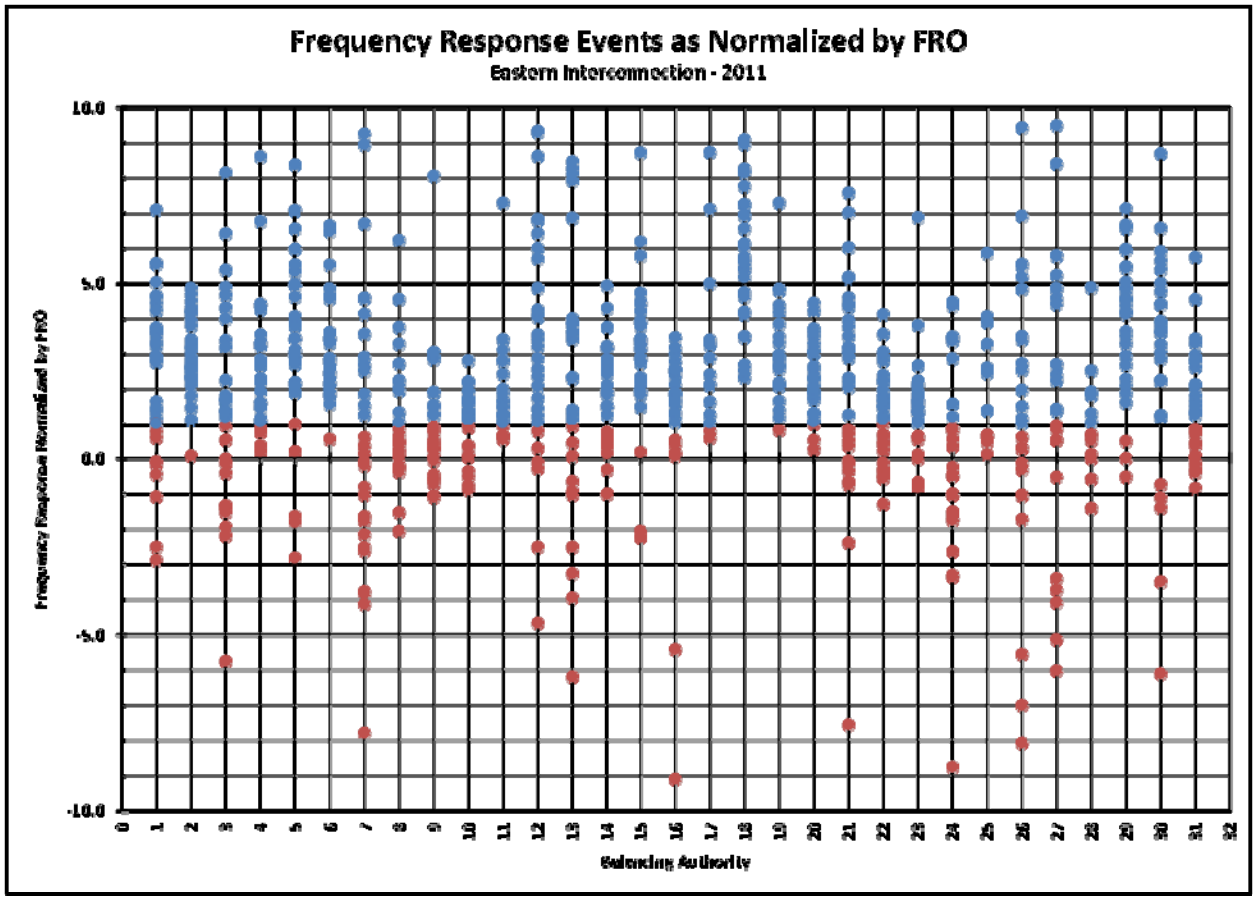
The use of a "single event measure" was considered early in the development of the FRS for compliance because a single event measure could be enforced for each event on the interconnection making compliance enforcement a simpler process. The variability of the measurement of Frequency Response for an individual BA for an individual Disturbance event was evaluated to determine its suitability for use as a compliance measure. The individual Disturbance events were normalized and plotted for each BA on the Eastern and Western Interconnections. This data was plotted with a dot representing each event. Events with a measured Frequency Response above the FRO were shown as blue dots and events with a measured Frequency Response below the FRO were shown as red dots. In order to show the full variability of the results the plots have been provided with two scales, a large scale to show all of the events and small scale to show the events closer to the FRO or a value of 1.0. This data is presented on four charts titled Frequency Response Events as Normalized by FRO.

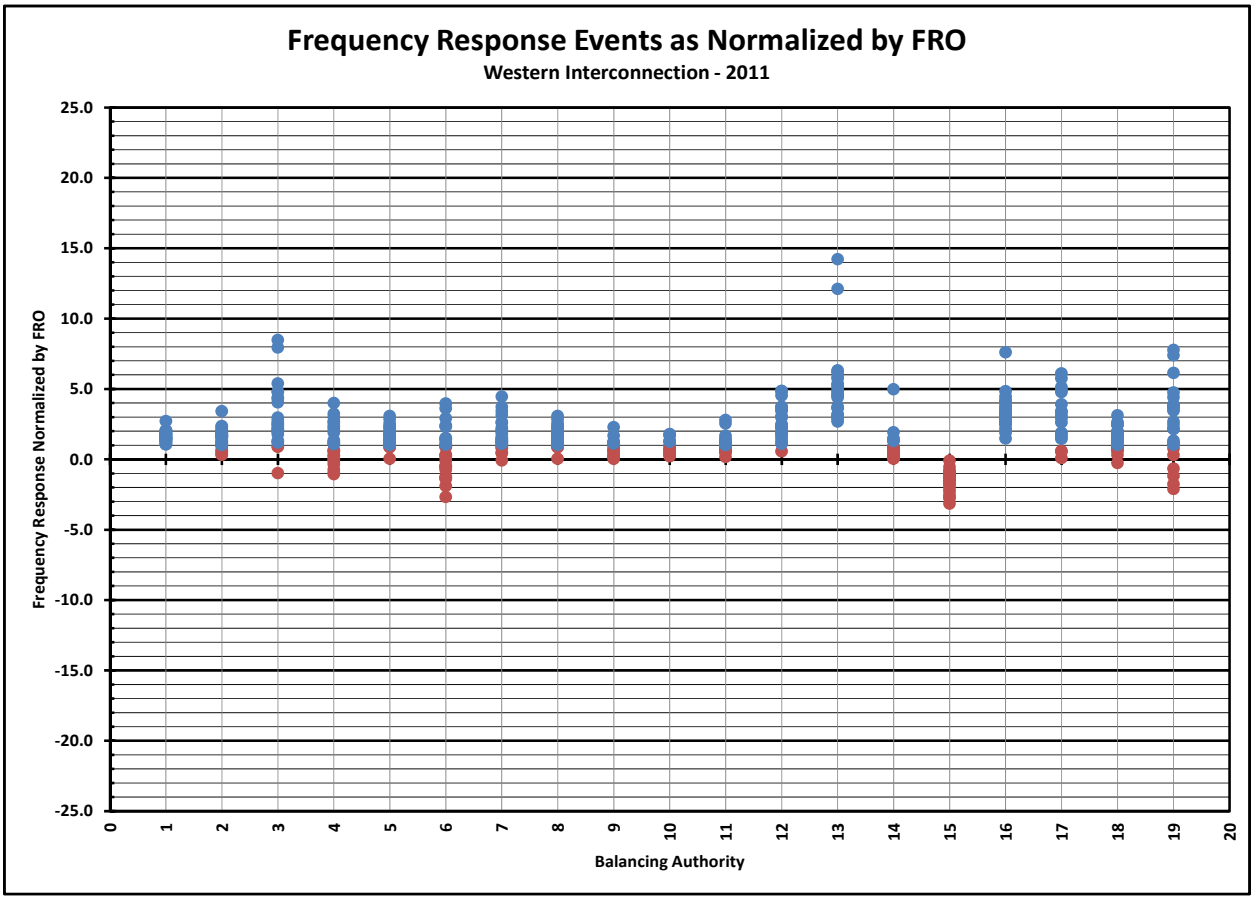
Analysis of this data indicates a single event based compliance measure is unsuitable for compliance evaluation when the data has the large degree of variability shown in these charts. Based on the field trial data provided, only 3 out of 19 BAs on the Western Interconnection would be compliant for all events with a standard based on a single event measure. Only 1 out of 31 BAs on the Eastern Interconnection would be compliant for all events with a standard based on a single event measure. The general consensus of the industry is that there is not a reliability issue with insufficient Frequency Response on any of the North American Interconnections at this time. Therefore, it is unreasonable to even consider a standard that would indicate over 90% of the BAs in North American to be non-compliant with respect to maintaining sufficient Frequency Response to maintain adequate reliability.

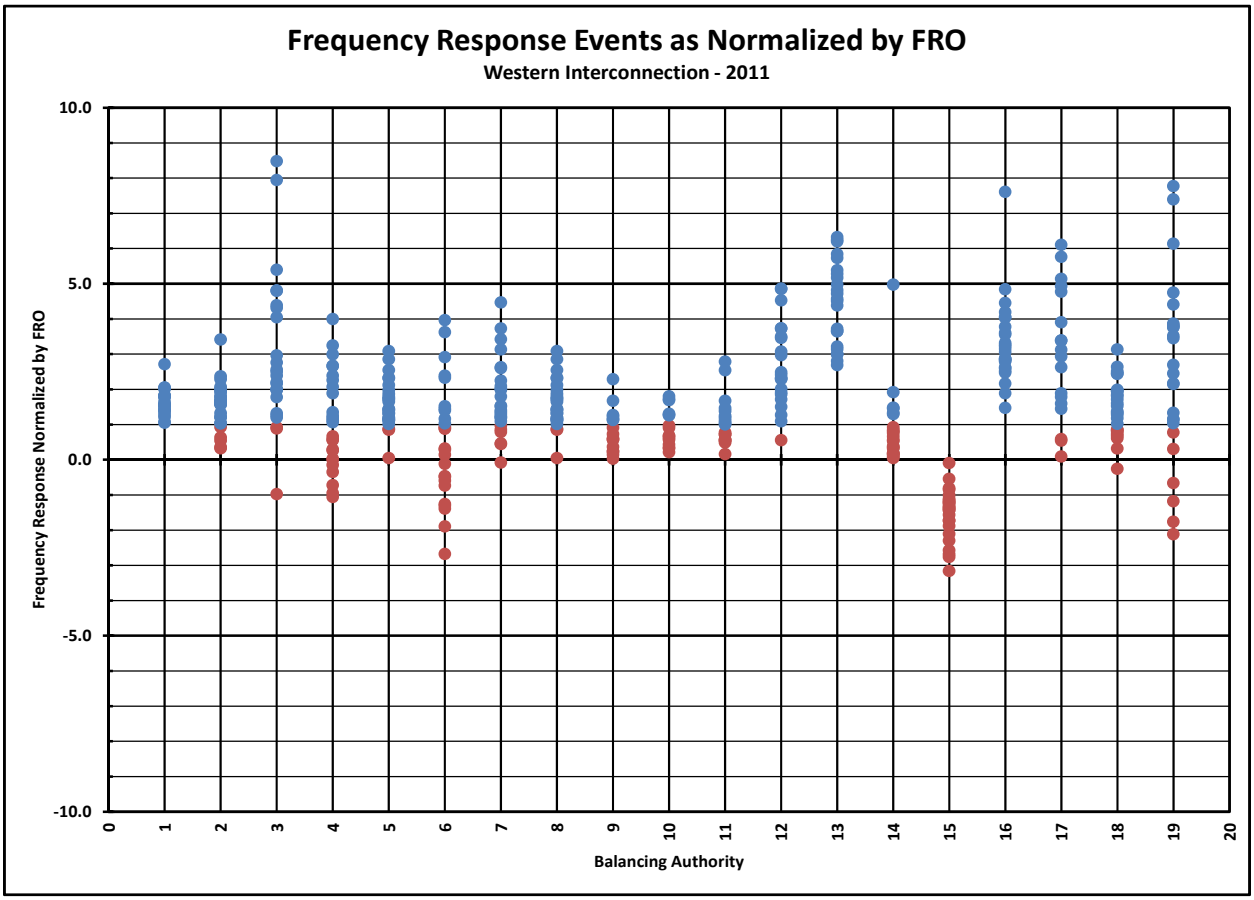
In an attempt to balance the workload of Balancing Authorities with the need for accuracy in the FRM, the standard will require at least 20 samples selected during the course of the year to compute the FRM. Research conducted by the FRSDT indicated that a Balancing Authority's FRM will converge to a reasonably stable value with at least 20 samples.

[8] Single Event Analysis based on results of Frequency Response Standard Field Trial Analysis, September 17, 2012.


Frequency Response Events as Normalized by FRO
Eastern Interconnection - 2011
Frequency Response Normalized by FRO
50.0
25.0
0.0
-25.0
-50.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32
Balancing Authority


Frequency Response Events as Normalized by FRO
Eastern Interconnection - 2011
10.0
5.0
0.0
-5.0
-10.0


Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
25.0
20.0
15.0
10.0
5.0
0.0
-5.0
-10.0
-15.0
-20.0
-25.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Balancing Authority


Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
10.0
5.0
0.0
-5.0
-10.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Balancing Authority

Sample Size
In order to support field trial evaluations of sample size, sampling intervals, and aggregation techniques, the FRSDT will be retrieving scan rate data from the Balancing Authorities for each SEFRD. Additional frequency events may also be requested for research purposes, though they will not be included in the FRM computation.

FERC Order No. 693 directed the ERO (at P 375) to define the number of Frequency Response surveys that were conducted each year and to define a necessary amount of Frequency Response. R1 addresses both of these directives:

- There is a single annual survey of at least 20 events each year.
- The FRM calculated on FRS Form 1 is compared by the ERO against the FRO determined 12 months earlier (when the last FRS Form 1 was submitted) to verify the Balancing Authority provided its share of Interconnection Frequency Response.

Median as the Standard's Measure of Balancing Authority Performance
The FRSDT evaluated different approaches for "averaging" individual event observations to compute a technically sound estimate of Frequency Response Measure. The MW contribution for a single BA in a multi-BA Interconnection is small compared to the minute to minute changes in load, interchange and generation. For example, a 3000 MW BA in the Eastern Interconnection may only be called on to contribute 10MW for the loss of a 1000MW. The 10 MW of governor and load response may easily be masked as a coincident change in load.

In general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FRSDT has shown the Median to be less influenced by noise in the measurement process and the team has chosen the median as the initial metric for calculating the BAs' Frequency Response Measure.

The FRSDT performed extensive empirical studies and engaged in lively discussions in an attempt to determine the best aggregation technique for a sample set size of at least 20 events. Mean, median, and linear regression techniques were used on a trial basis with the data that was available during the early phases of the effort.

A key characteristic of the "aggregation challenge" is related to the use of actual net interchange data for measuring frequency response. The tie line flow measurements are varying continuously due to other operational phenomena occurring concurrently with the provision of frequency response. (*See* Appendix 1 for details.) All samples have "noise" in them, as most operational personnel who have computed the frequency response of their BA can attest. What has also become apparent to the FRSDT is that while the majority of the frequency response samples have similar levels of noise in them, a few of the samples may have much larger errors in them than the others that result in unrepresentative results. And with the sample set size of interest, it is common to have unrepresentative errors in these few samples to be very large and asymmetric. For example, one BA's subject matter expert observed recently that 4 out of 31 samples had a much larger error contribution than the other 27 samples, and that 3 out of 4 of the very high error samples grossly underestimated the frequency response. The median value demonstrated greater resiliency to this data quality problem than the mean with this data set. (The median has also demonstrated superiority to

linear regression in the presence of these described data quality problems in other analyses conducted by the FRSDT, but the linear regression showed better performance than the mean.)

The above can be demonstrated with a relatively simple example. Let's assume that a Balancing Authority's true frequency response has an average value of -200 MW/ .1 Hz. Let's also assume that this Balancing Authority installed "special" perfect metering on key loads and generators, so that we could know the true frequency response of each sample. And then we will compare them with that measured by typical tie line flow metering, with the kind of noise and error that occurs commonly and "not so commonly". Let's start with the following 4 samples having a common level of noise, with MW/ .1 Hz as the unit of measurement.

Perfect measurement	Noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	Mean	-205
-200	Median	-215

Now let's add a fifth sample, which is highly contaminated with noise and error that grossly underestimates frequency response.

Perfect measurement	Noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	250	+50
-200	Mean	-154
-200	Median	-210

It is clear from the above simplistic example that the mean drops by about 25% while the median is affected minimally by the single highly contaminated value.

Based on the analyses performed thus far, the FRSDT believes that the median's superior resiliency to this type of data quality problem makes it the best aggregation technique at this time. However, the FRSDT sees merit and promise in future research with sample filtering combined with a technique such as linear regression.

When compared with the mean, linear regression shows superior performance with respect to the elimination of noise because the measured data is weighted by the size of the frequency change associated with the event. Since the noise is independent from frequency change, the greater weighting on larger events provides a superior technique for reducing the effect of noise on the results.

However, linear regression does not provide a better method when dealing with a few samples with large magnitudes of noise and unrepresentative error. There are only two alternatives to improve over the use of median when dealing with these larger unrepresentative errors:

1. Increase the sample size, or
2. Actively eliminate outliers due to unrepresentative error.

Unfortunately, the first alternative, increasing the sample size is not available because significantly more sample events are not available within the measurement time period of one year. Linear regression techniques are being investigated that have an active outlier elimination algorithm that would eliminate data that lie outside ranges of the 96th percentile and 99th percentile, for example.

Still, the use of linear regression has value in the context of this standard. The NERC Resources Subcommittee will use linear regression to evaluate Interconnection frequency response, particularly to evaluate trends, seasonal impacts, time of day influences, etc. The Good Practices and Tools section of this document outlines how a BA can use linear regression to develop a predictive tool for its operators.

Additional discussion on this topic is contained in "Appendix 1 – Data Quality Concerns Related to the Use of Actual Net Interchange Value" of this document.

The NERC Frequency Response Initiative Report addressed the relative merits of using the median versus linear regression for aggregating single event frequency response samples into a frequency response measurement score for compliance evaluation. This report provided 11 evaluation criteria as a basis for recommending the use of linear regression instead of the median for the frequency response measurement aggregation technique. The FRSDT made its own assessment on the basis of these evaluation criteria on September 20, 2012, but concluded that the median would be the best aggregation technique to use initially when the relative importance of each criterion was considered. A brief summary of the FRSDT majority consensus on the basis of each evaluation criterion is provided below.

- Provides two dimensional measurement – The FRSDT agrees that the two dimensional concept is a useful way to perceive frequency response characteristics, and that it may be useful for potential future modeling activities. Better data quality would increase support for such future efforts, and the use of the median for initial compliance evaluations within BAL-003-1 should not hinder any such effort. The FRSDT perceived this as a mild advantage for linear regression.
- Represents nonlinear characteristics – With considerations similar to those applied to the previous criterion, the FRSDT perceived this as a mild advantage for linear regression.
- Provides a single best estimator – The FRSDT gave minimal importance to the characteristic of the median averaging the middle values when used with an even number of samples.
- Is part of a linear system - With considerations similar to those applied to the first two criteria, the FRSDT perceived this as a mild advantage for linear regression (particularly in the modeling area.)
- Represents bimodal distributions – The FRSDT gave minimal weight of this criterion, as a change in Balancing Authority footprint does not seem to be addressed adequately by any aggregation technique.
- Quality statistics available – The FRSDT perceived this as a mild advantage for linear regression in that the statistics would be coupled directly to the compliance evaluation. The FRSDT also included this criterion as part of the modeling advantages cited above.

The FRSDT supports collecting data and performing quality statistical analysis. If it is determined that the use of the median, as opposed to a mean or linear regression aggregation, is yielding undesirable consequences, the FRSDT recommends that other aggregation techniques be re-evaluated at that time.

- Reducing influence of noise - This is the dominant concern of the FRSDT, and it perceives the median to have a major advantage over linear regression in addressing noise in the change in actual net interchange calculation. The FRSDT bases this judgment on: prior FRSDT studies that have shown that the median produces more stable results; the data used in the NERC Frequency Response Initiative document exhibits large quantities of noise; prior efforts of FRSDT members in performing frequency response sampling for their own Balancing Authorities over many years; and similar observations of noise in the CERTS frequency Monitoring Application. The FRSDT has serious concerns that the influence of noise has a greater tendency to yield a "false positive" compliance violation with linear regression than with the median. Also, limited studies performed by the FRSDT indicates the possibility that the resultant frequency response measure would yield more measurement variation across years with linear regression versus the median while the actual Balancing Authority performance remains unchanged.
- Reducing the influence of outliers – This is related to the previous criterion. The FRSDT recognizes four main sources of noise: concurrent operating phenomena (described elsewhere in this document), transient tie line flows for nearby contingencies, data acquisition time skew in tie line data measurements, and time skew and data compression issues in archiving techniques and tools such as PI. Some outliers may be caused in part by true variation in the actual frequency response, and it is desirable to include those in the frequency response measure. The FRSDT supports efforts in the near future to distinguish between outliers caused by noise versus true frequency response, and progress in this area may make it feasible and desirable to replace the median with linear regression, or some other validated technique. The FRSDT does note that this is a substantial undertaking, and it would require substantial input from a sufficient number of experts to help distinguish noise from true frequency response.
- Easy to calculate – The FRSDT perceives this to be a minor to moderate advantage for the median. However, more complex (but reasonably so) techniques would receive more support if clear progress can be made in noise elimination.
- Familiar indicator – The FRSDT perceives this to be a minor to moderate advantage for the median. However, more complex (but reasonably so) techniques would receive more support if clear progress can be made as a result of noise elimination.
- Currently used as a measure in BAL-003 – The present standard refers to an average and does not provide specific guidance on the computation of that average, but the FRSDT puts minimal weight on this evaluation criterion.

In summary, the FRSDT perceives an approximate balance between the modeling advantage for linear regression and the simplicity advantage of the median. However, the clear determinant in endorsing the use of the median is the data quality issue related to concurrent operational phenomena, transient tie line flows, and data acquisition and archiving limitations.

FERC Order No. 693 also directed the Standard (at P 375) to identify methods for Balancing Authorities to obtain Frequency Response. Requirement R1 allows Balancing Authorities to participate in Frequency Response Sharing Groups (FRSGs) to provide or obtain Frequency Response. These may be the same FRSGs that cooperate for BAL-002-0 or may be FRSGs that form for the purposes of BAL-003-1.

If BAs participate as an FRSG for BAL-003-1, compliance is based on the sum of the participants' performance.

Two other ways that BAs could obtain Frequency Response are through Supplemental Service or Overlap Regulation Service:

- No special action is needed if a BA provides or receives supplemental regulation. If the regulation occurs via Pseudo Tie, the transfer occurs automatically as part of Net Actual Interchange (NIA) and in response to information transferred from recipient to provider.
- If a BA provides overlap regulation, its FRS Form 1 will include the Frequency Bias setting as well as peak load and generation of the combined Balancing Authority Areas. The FRM event data will be calculated on the sum of the provider's and recipient's performance.

In the Violation Severity Levels for Requirement R1, the impact of a BA not having enough frequency response depends on two factors:

- Does the Interconnection have sufficient response?
- How short is the BA in providing its FRO?

The VSL takes these factors into account. While the VSLs look different than some other standards, an explanation would be helpful.

VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plane as single-BA Interconnections.

Consider a small BA whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response, because this would treat multi-BA Interconnections more harshly than single BA Interconnections on a significant scale.

The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.

Requirement 2

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.

Background and Rationale

Attachment A of the Standard discusses the process the ERO will follow to validate the BA's FRS Form 1 data and publish the official Frequency Bias Settings. Historically, it has taken multiple rounds of validation and outreach to confirm each BA's data due to transcription errors, misunderstanding of instructions, and other issues. While BAs historically submit Bias Setting data by January 1, it often takes one or more months to complete the process.

The target is to have BAs submit their data by January 10. The BAs are given 30 days to assemble their data since the BAs are dependent on the ERO to provide them with FRS Form 1, and there may be process delays in distributing the forms since they rely on identification of frequency events through November 30 of the preceding year.

Frequency Bias Settings generally change little from year to year. Given the fact that BAs can encounter staffing or EMS change issues coincident with the date the ERO sets for new Frequency Bias Setting implementation, the standard provides a 24 hour window on each side of the target date.

To recap the annual process:

1. The ERO posts the official list of frequency events to be used for this Standard in early December. The FRS Form 1 for each Interconnection will be posted shortly thereafter.

2. The Balancing Authority submits its revised annual Frequency Bias Setting value to NERC by January 10.

3. The ERO and the Resources Subcommittee validate Frequency Bias Setting values, perform error checking, and calculate, validate, and update CPS2 L10 values. This data collection and validation process can take as long as two months.

4. Once the L10 and Frequency Bias Setting values are validated, The ERO posts the values for the upcoming year and also informs the Balancing Authorities of the date on which to implement revised Frequency Bias Setting values. Implementation typically would be on or about March 1st of each year.

BAL-003-0.1b standard requires a minimum Frequency Bias Setting equal in absolute value to one percent of the Balancing Authority's estimated yearly peak demand (or maximum generation level if native load is not served). For most Balancing Authorities this calculated amount of Frequency Bias is significantly greater in absolute value than their actual Frequency Response characteristic (which represents an over-bias condition) resulting in over-control

since a larger magnitude response is realized. This is especially true in the Eastern Interconnection where this condition requires excessive secondary frequency control response which degrades overall system performance and increases operating cost as compared to requiring an appropriate balance of primary and secondary frequency control response.

Balancing Authorities were given a minimum Frequency Bias Setting obligation because there had never been a mandatory Frequency Response Obligation. This historic "one percent of peak per 0.1Hz" obligation, dating back to NERC's predecessor, NAPSIC, was intended to ensure all BAs provide some support to Interconnection frequency.

The ideal system control state exists when the Frequency Bias Setting of the Balancing Authority exactly matches the actual Frequency Response characteristic of the Balancing Authority. If this is not achievable, over-bias is significantly better from a control perspective than under-bias with the caveat that Frequency Bias is set relatively close in magnitude to the Balancing Authority actual Frequency Response characteristic. Setting the Frequency Bias to better approximate the Balancing Authority natural Frequency Response characteristic will improve the quality and accuracy of ACE control, CPS & DCS and general AGC System control response. This is the technical basis for recommending an adjustment to the long standing "1% of peak/0.1Hz" Frequency Bias Setting. The Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard is intended to bring the Balancing Authorities' Frequency Bias Setting closer to their natural Frequency Response. Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard balances the following objectives:

- Bring the Frequency Bias Setting and Frequency Response closer together.
- Allow time to analyze impact on other Standards (CPS, BAAL and to a lesser extent DCS) by adjustments in the minimum Frequency Bias Setting, by accommodating only minor adjustments.
- Do not allow the Frequency Bias Setting minimum to drop below natural Frequency Response, because under-biasing could affect an Interconnection adversely.

Additional flexibility has been added to the Frequency Bias Setting based on the actual Frequency Response (FRM) by allowing the Frequency Bias Setting to have a value in the range from 100% of FRM to 125% of FRM. This change has been included for the following reasons:

- When the new standardized measurement method is applied to BAs with a Frequency Response close to the interconnection minimum response, the requirement to use FRM is as likely to result in a Frequency Bias Setting below the actual response as it is to result in a response above the actual response. From a reliability perspective, it is

always better to have a Frequency Bias Setting slightly above the actual Frequency Response.

- As with single BA interconnections, the tuning of the control system may require that the BA implement a Frequency Response Setting slightly greater in absolute terms than its actual Frequency Response to get the best performance.
- The new standardized measurement method for determining FRM in some cases results in a measured Frequency Response significantly lower than the previous methods used by some BAs. It is desirable to not require significant change in the Frequency Bias Setting for these BAs that experience a reduction in their measured Frequency Response.

Requirement 3

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is:

- *Less than zero at all times, and*
- *Equal to or more negative than its Frequency Response Obligation when the Frequency varies from 60 Hz by more that +/- 0.036 Hz.*

Background and Rationale

In multi-Balancing Authority interconnections, the Frequency Bias Setting should be coordinated among all BAs on the interconnection. When there is a minimum Frequency Bias Setting requirement, it should apply for all BAs. However, BAs using a variable Frequency Bias Setting may have non-linearity in their actual response for a number of reasons including the dead-bands implemented on their generator governors. The measurement to ensure that these BAs are conforming to the interconnection minimum is adjusted to remove the dead-band range from the calculated average Frequency Bias Setting actually used. For BAs using variable bias, FRS Form 1 has a data entry location for the previous year's average monthly Bias. The Balancing Authority and the ERO can compare this value to the previous year's Frequency Bias Setting minimum to ensure R3 has been met.

On single BA interconnections, there is no need to coordinate the Frequency Bias Setting with other BAs. This eliminates the need to maintain a minimum Frequency Bias Setting for any reason other than meeting the reliability requirement as specified by the Frequency Response Obligation.

Requirement 4

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:

- *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 as shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.*

Background and Rationale

This requirement reflects the operating principles first established by NERC Policy 1 and is similar to Requirement R6 of the approved BAL-003-0.1b standard. Overlap Regulation Service is a method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into the providing Balancing Authority's AGC/ACE equation.

As noted earlier, a BA that is providing Overlap Regulation will report the sum of the Bias Settings in its FRS Form 1. Balancing Authorities receiving Overlap Regulation Service have an ACE and Frequency Bias Setting equal to zero (0).

How this Standard Meets the FERC Order No. 693 Directives

FERC Directive

The following is the relevant paragraph of Order No. 693.

> *Accordingly, the Commission approves Reliability Standard BAL-003-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL-003-0 through the Reliability Standards development process that: (1) includes Levels of Non-Compliance; (2) determines the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) defines the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved.*

1. Levels of Non-Compliance

VRFs and VSLs are an equally effective way of assigning compliance elements to the standard.

2. Determine the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other Requirements of the Reliability Standard are met

BAL-003 V0 R2 (the basis of Order No. 693) deals with the calculation of Frequency Bias Setting such that it reflects natural Frequency Response.

The drafting team has determined that a sample size on the order of at least 20 events is necessary to have a high confidence in the estimate of a BA's Frequency Response. Selection of the frequency excursion events used for analysis will be done via a method outlined in Attachment A to the Standard.

On average, these events will represent the largest 2-3 "clean" frequency excursions occurring each month.

Since Frequency Bias Setting is an annual obligation, the survey of the at least 20 frequency excursion events will occur once each year.

3. Define the necessary amount of Frequency Response needed for Reliable Operation for each Balancing Authority with methods of obtaining and measuring that the frequency response is achieved

Necessary Amount of Frequency Response

The drafting team has proposed the following approach to defining the necessary amount of frequency response. In general, the goal is to avoid triggering the first step of under-frequency load shedding (UFLS) in the given Interconnection for reasonable contingencies expected. The

methodology for determining each Interconnection's and Balancing Authority's obligation is outlined in Attachment A to the Standard.

It should be noted the standard cannot guarantee there will never be a triggering of UFLS as the magnitude of "point C" differs throughout an interconnection during a disturbance and there are local areas that see much wider swings in frequency.

The contingency protection criterion is the largest reasonably expected contingency in the Interconnection. This can be based on the largest observed credible contingency in the previous 10 years or the largest Category C event for the Interconnection.

Attachment A to the standard presents the base obligation by Interconnection and adds a Reliability Margin. The Reliability Margin included addresses the difference between Points B and C and accounts for variables.

For multiple BA interconnections, the Frequency Response Obligation is allocated to BAs based on size. This allocation will be based on the following calculation:

$$\mathrm{FRO_{BA}} = \mathrm{FRO_{Int}} \times \frac{\text{Annual Gen}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annual Gen}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}$$

Methods of Obtaining Frequency Response

The drafting team believes the following are valid methods of obtaining Frequency Response:

- Regulation services.
- Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.
- Through a tariff (e.g. Frequency Response and regulation service).
- From generators through an interconnection agreement.
- Contract with an internal resource or loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).

Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.

Measuring that the Frequency Response is Achieved

FRS Form 1 and the underlying data retained by the BA will be used for measuring whether Frequency Response was provided. FRS Form 1 will provide the guidance on how to account for and measure Frequency Response.

Going Beyond the Directive

Based on the combined operating experience of the SDT, the drafting team consensus is that each Interconnection has sufficient Frequency Response. If margins decline, there may be a need for additional standards or tools. The drafting team and the Resources Subcommittee are working with the ERO on its Frequency Response Initiative to develop processes and good practices so the Interconnections are prepared. These good practices and tools are described in the following section.

The drafting team is also evaluating a risk-based approach for basing the Interconnection Frequency Response Obligation on an historic probability density of frequency error, and for allocating the obligation on the basis of the Balancing Authority's average annual ACE share of frequency error. This allocation method uses the inverse of the rationale for allocating the CPS1 epsilon requirement by Bias share.

Good Practices and Tools

Background

This section outlines tips and tools to help Balancing authorities meet the Frequency Response Standard or to operate more reliably. If you have suggested additions, please send them to balancing@nerc.com.

Identifying and Estimating Frequency Responsive Reserves

Knowing the quantity and depth of frequency responsive reserves in real time is a possible next step to being better prepared for the next event. The challenge in achieving this is having the knowledge of the capabilities of all sources of frequency response. Presently the primary source of Frequency Response remains with the generation resources in our fleets.

Understanding how each of these sources performs to changes in system frequency and knowing their limitations would improve the BA's ability to measure frequency responsive reserves. Presently there are only guidelines, criteria and protocols in some regions of the industry that identify specific settings and performance expectations of Primary Frequency Response of resources.

One method of gaining a better understanding of performance is to measure performance during actual events that occur on the system. Measuring performance during actual events would only provide feedback for performance during that specific event and would not provide insight into depth of response or other limitations.

Repeated measurements will increase confidence in expected performance. NERC modeling standards are in process to be revised that will improve the BA's insight into predicting available frequency responsive reserves. However, knowing how resources are operated, what modes of operation provide sustained Primary Frequency Response and knowing the operating range of this response would give the BA the knowledge to accurately predict frequency response and the amount of frequency responsive reserves available in real time.

Some benefits have been realized by communicating to generation resources (GO) the importance of operating in modes that allow Primary Frequency Response to be sustained by the control systems of the resource. Other improvements in implementation of Primary Frequency Response have been achieved through improved settings on turbine governors through the elimination of "step" frequency response with the simultaneous reduction in governor dead-band settings.

Improvements in the full AGC control loop of the generating resource, which accounts for the expected Primary Frequency Response, have improved the delivery of quality Primary Frequency Response while minimizing secondary control actions of generators. Some of these actions can provide quick improvement in delivery of Primary Frequency Response.

Once Primary Frequency Response sources are known, the BA could calculate available reserves that are frequency responsive. Planning for these reserves during normal and emergency operations could be developed and added to the normal planning process.

Using FRS Form 1 Data

The information collected for this standard can be supplemented by a few data points to provide the Balancing Authority useful tools and information. The BA could do a regression analysis of its frequency response against the following values:

- Load (value A).
- Interchange (Value A).
- Total generation.
- Spinning reserve.

While the last two values above are not part of Form 1, they should be readily available. Small BAs might even include headroom on its larger generators as part of the regression.

The regression would provide a formula the BA could program in its EMS to present the operator a real time estimate of the BA's Frequency Response.

Statistical outliers in the regression would point to cases meriting further inspection to find causes of low Frequency Response or opportunities for improvement.

Tools

Single generating resource performance evaluation tools for steam turbine, combustion turbine (simple cycle or combined cycle) and for intermittent resources are available at the following link. http://texasre.org/standards_rules/standardsdev/rsc/sar003/Pages/Default.aspx.

These tools and the regional standard associated with them are in their final stages of development in the Texas region.

These tools will be posted on the NERC website.

References

NERC *Frequency Response Characteristic Survey Training Document* (Found in the NERC Operating Manual)

NERC Resources Subcommittee Position Paper on Frequency Response

NERC TIS Report *Interconnection Criteria for Frequency Response Requirements (for the Determination Interconnection Frequency Response Obligations (IFRO)*

Frequency Response Standard Field Trial Analysis, September 17, 2012

Appendix 1 - Data Quality Concerns Related To The Use Of The Actual Net Interchange Value

Actual net interchange for a typical Balancing Authority (BA) is the summation of its tie lines to other BAs. In some cases, there are pseudo-ties in it which reflect the effective removal or addition of load and/or generation from another BA, or it could include supplemental regulation as well. But in the typical scenario, actual net interchange values that are extracted from EMS data archiving can be influenced by data latency times in the data acquisition process, and also any timestamp skewing in the archival process.

Of greater concern, however, are the inevitable variations of other operating phenomena occurring concurrently with a frequency event. The impacts of these phenomena are superimposed on actual net interchange values along with the frequency response that we wish to measure through the use of the actual net interchange value.

To explore this issue further, let's begin with the idealized condition:

- frequency is fairly stable at some value near or a little below 60 Hz
- ACE of the non-contingent BA of interest is 0 and has been 0 for an extended period, and AGC control signals have not been issued recently
- Actual net interchange is "on schedule", and there are no schedule changes in the immediate future
- BA load is flat
- All generators not providing AGC are at their targets
- Variable generation such as wind and solar are not varying
- Operators have not directed any manual movements of generation recently

And when the contingency occurs in this idealized state, the change in actual net interchange will be measuring only the decline in load due to lesser frequency and generator governor response, and, none of the contaminating influences. While the ACE may become negative due to the actual frequency response being less than that called for by the frequency bias setting within the BA's AGC system, this contaminating influence on measuring frequency response will not appear in the actual net interchange value if the measurement interval ends before the generation on AGC responds.

Now let's explore the sensitivity of the resultant frequency response sampling to the relaxation of these idealized circumstances.

1. The "60 Hz load" increases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be reduced by the moderate increase in load and the frequency response will be underestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be increased by the AGC response (and/or manual adjustments) and the frequency response will be overestimated.

2. The “60 Hz load” decreases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be increased by the moderate reduction in load and the frequency response will be overestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be decreased by the AGC response (and/or manual adjustments) and the frequency response will be underestimated.
3. In anticipation of increasing load during the next hour, the operator increases manual generation before the load actually appears. If the frequency event happens while the generation “leading” the load is increasing, then the actual net interchange will be increased by the increase in manual generation and the frequency response will be overestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator’s leading actions take effect, then the actual net interchange will be decreased and the frequency response is underestimated.
4. In anticipation of decreasing load during the next hour, the operator decreases manual generation before the load actually declines. If the frequency event happens while the generation “leading” the load downward is decreasing, then the actual net interchange will be decreased by the reduction in manual generation and the frequency response will be underestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator’s leading actions take effect, then the actual net interchange will be increased and the frequency response is overestimated.
5. A schedule change to export more energy is made at 5 minutes before the top of the hour. The BA’s “60 Hz load” is not changing. The schedule change is small enough that the operator is relying on upward movement of generators on AGC to provide the additional energy to be exported. The time at which the AGC generators actually begin to provide the additional energy is dependent on how much time passes before the AGC algorithm gets out of its deadbands, the individual generator control errors get large enough for sending out the control signal, and maybe 20 seconds to 3 minutes for the response to be effected. The key point here is that it is not clear when the effects of a schedule change, as manifested in a change in generation and then ultimately a change in actual net interchange, will occur.
6. With the expected penetration of wind in the near future, unanticipated changes in their output will tend to affect actual net interchange and add noise to the frequency response observation process.

To a greater or lesser extent, 1 through 4 above are happening continuously for the most part with most BAs in the Eastern and Western Interconnections. The frequency response is buried within the typical hour to hour operational cacophony superimposed on actual net interchange values. The choice of metrics will be important to artfully extract frequency response from the noise and other unrepresentative error.

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Implementation Plan

Project 2017-01 Modifications to BAL-003-1.1
Reliability Standard BAL-003-2

Applicable Standard

- Standard BAL-003-2 — Frequency Response and Frequency Bias Setting

Requested Retirement(s)

- Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting

Applicable Entities

- Balancing Authority
  - 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.
- Frequency Response Sharing Group

Background

The BAL-003-2 Phase I portion of the project revises the BAL-003-1.1 standard and process documents to address: (1) the inconsistencies in calculation of IFROs due to interconnection Frequency Response performance changes of Point C and/or Value B; (2) the Eastern Interconnection Resource Contingency Protection Criteria; (3) the frequency of nadir point limitations (currently limited to t0 to t+12); (4) clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities; and (5) enhancements to the BAL-003-1 FRS Forms that include the ability to collect and submit FRSG performance data. Additionally, the supporting procedural and process steps have been removed from Attachment A and captured in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.* This proposed document would be subject to approval by the North American Electric Reliability Corporation Operating Committee and Board of Trustees, and subject to informational filing with the Federal Energy Regulatory Commission, to facilitate timely process improvements as future lessons are learned.

Effective Date

BAL-003-2 — Frequency Response and Frequency Bias Setting

Where approval by an applicable governmental authority is required, the standard shall become effective on the first operating year (which begins on December 1) that is 90 days 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 operating year (which begins on December 1) that is 90 days after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

BAL-003-1.1 — Frequency Response and Frequency Bias Setting
Reliability Standard BAL-003-1.1 shall be retired immediately prior to the effective date of BAL-003-2 in the particular jurisdiction in which the revised standard is becoming effective.

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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 events 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. The ~~P~~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~~for 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 Megawatts (MWs) 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~~ Error (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:

NERC will request ~~Balancing Authorities~~BAs to provide: their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event or largest resource as described above. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

~~NERC will request Balancing Authorities or Frequency Response Sharing Groups to provide: their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event or largest resource as described above. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be voluntary on the part of the Balancing Authorities but will be needed to complete the calculation of the RLPC and IFRO.~~

~~Balancing Authorities~~BAs determine the two largest ~~potential~~ resource losses for the next operating year based on a review of the following items:

- The two largest Balancing Contingency Events due to a single contingency identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FRS Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If th~~e~~is RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.
The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation). DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

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	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B= 500 MW	Electrically separate

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

Largest Resource Loss = 1500 MW
Second Largest Resource Loss = 1400 MW
Summation of two largest resource losses = 2900 MW
Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or 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 Resource Loss A = 1150 MW
BA1 Resource Loss B = 800 MW
BA2 Resource Loss A = 1380 MW
BA2 Resource Loss B = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 Resource Loss A = 800 MW
BA3 Resource Loss B = 700 MW

In this ~~case~~case, the ERO would determine the RLPC as ~~follows,~~follows~~;~~: the summation of the two largest resource losses ~~are~~is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

~~North American~~ Interconnection ~~RPLC~~ RLPC Values

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

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
~~MSSC1~~RESOURCE LOSS A = 1732 MW
~~MSSC2~~RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

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

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
~~MSSC1~~RESOURCE LOSS A = 1375 MW
~~MSSC2~~RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
~~MSSC1~~RESOURCE LOSS A = 1000 MW
~~MSSC2~~RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

Standard Authorization Request (SAR) Form

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

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

Requested information			
SAR Title:	Standards Alignment with Registration		
Date Submitted:			
SAR Requester			
Name:	Revised by Project 2017-07 Standards Alignment with Registration SAR Drafting Team Stephen Wendling, Chair		
Organization:	American Transmission Company		
Telephone:	(608) 877-8232	Email:	swendling@atcllc.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
This project will align the Reliability Standards with the outcome of the Risk-Based Registration (RBR) initiative.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project would modify Reliability Standards to be consistent with the FERC-approved changes to registration as part of the RBR initiative.			
Project Scope (Define the parameters of the proposed project):			
This project will review and align Reliability Standards impacted by the RBR initiative.			
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):			
This project will formally address any remaining edits to the Reliability Standards that are needed to align the existing standards with the RBR initiatives. The edits include updates to the BAL, CIP, FAC, INT, IRO, MOD, NUC, and TOP family of standards to remove the references to Purchasing-Selling Entities			

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

Requested information
(PSEs) and Interchange Authorities (IAs); references to the Load-Serving Entity (LSEs) will be removed or replaced by ~~either the Distribution Provider (DP), the Balancing Authority (BA), or~~ the appropriate functional ~~applicable~~ entity. ~~Additionally, t~~The project will include adding Underfrequency Load Shedding (UFLS)-only Distribution Providers (DPs) to the Applicability ~~Section~~ section of PRC-005 and PRC-006 per NERC registration criteria.~~; and review the Applicability sections of PRC-004 and PRC-008 and revise, as appropriate, to add UFLS-only DPs.~~ Additionally, the project will consider whether to include a definition for UFLS into the NERC Glossary of Terms, as well as review the standards to ensure consistent use of the term Planning Coordinator. The clean-up effort of the standards can be categorized into the following: 1. Modifications to existing standards where the removal of the retired function may need replacement by another function. For instance, Reliability Standard MOD-032-1 specifies certain data from LSEs that may need to be provided by other functional entities going forward. 2. Modifications where the applicable entity and references may be removed. These updates may be able to follow a similar process to the Paragraph 81 initiatives where standards are redlined and posted for industry comment and ballot. A majority of the edits would simply remove deregistered functional entities and their applicable requirements/references. The impacted standards include the BAL, CIP, IRO, and TOP family of standards. Additionally, PRC-005~~-1.1b~~ and PRC-006~~-003~~ will be updated to add UFLS-only DP to the Applicability ~~Sections~~sections. ~~and a review of the Applicability Sections of PRC-004-5(i) and PRC-008-0 to add, as appropriate, UFLS-only DP to align with the post-RBR registration impacts.~~ 3. Initiatives that can address RBR updates through the periodic review process. ~~-~~The 2017-07 SAR drafting team should consider whether it or the periodic review teams currently reviewing those standards should make the necessary revisions. ~~This would include the INT-004-3.1 and NUC-001-3 standards. Rather than the Project 2017-07 making the revisions the SDT could coordinate with the periodic review teams currently reviewing INT-004-3.1 and NUC-001-3 so that any changes resulting from those periodic reviews, if any, may be proposed at the same time after completion of each periodic review.~~
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
No additional costs outside of the time and resources needed to serve on the SAR and Standard Drafting Team.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.* Dispersed Generation Resources):
None
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.* Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):

Requested information
Since LSE is being removed or replaced by either the Distribution Provider (DP), the Balancing Authority (BA), or the appropriate Applicable Entity for the standards that need to be updated, those entities will likely be best suited for the MOD and PRC updates.
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
None
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

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

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes

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

Market Interface Principles	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
NPCC and SERC	~~UFLS-only DP will be added to the Applicability Section of PRC-006 and will create a variance of the following two~~ Regional Reliability Standards: PRC-006-NPCC-1 PRC-006-SERC-01 PRC-006-SERC-02

For Use by NERC Only

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

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	~~January X~~December 11, 2017	Standards Information Staff	Revised
3	February 1, 2018	Standards Information Staff	Revised

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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)	
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Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
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Identified Existing or Potential Regional or Interconnection Variances	
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NPCC and SERC	Regional Reliability Standards: PRC-006-NPCC-1 PRC-006-SERC-01 PRC-006-SERC-02

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2	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

PRC-024-3 is posted for a 45-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	December 2018
SAR posted for comment	December 19, 2018 – January 19, 2019
Standards Committee accepted the revised SAR	February 20, 2019

Anticipated Actions	Date
45-day formal or informal comment period with ballot	April – June 2019
45-day formal or informal comment period with additional ballot	July – August 2019
10-day final ballot	October 2019
Board adoption	November 2019

A. Introduction

1. **Title:** Generator Frequency and Voltage Protection ~~Protective Relay~~ Settings

2. **Number:** PRC-024-3~~PRC-024-2~~

3. **Purpose:** ~~Ensure Generator Owners~~ To ~~their~~ set generator protection, ~~protective relays~~ such that generating resource(s) ~~units~~ remain connected, continuing to support the BES during defined frequency and voltage excursions.

4. **Applicability:**

   4.1. ~~Generator Owner~~ Functional Entities:

   4.1.1. Generator Owners that apply protection listed in Section 4.2.1.

   4.1.2. Transmission Owners that own a BES generator step-up (GSU) transformer or collector transformer and apply protection listed in Section 4.2.1.

   4.2. Facilities:

   4.2.1 Frequency, voltage or volts per hertz protection, including frequency or voltage protective functions within control systems that provide tripping or momentary cessation signals to all or part of the generating resource, applied to the following:

   4.2.1.1 Bulk Electric System (BES) generating resource(s).

   4.2.1.2 BES GSU transformer(s).

   4.2.1.3 High side of the generator-connected unit auxiliary transformer installed on BES generating resource(s).

   4.2.1.4 Individual dispersed power producing resources identified in the BES Definition, Inclusion I4.

   4.2.1.5 Elements utilized in aggregation of the dispersed power producing resources.

   4.2.1.6 Collector transformer of resources identified in the BES Definition, Inclusion I4.

5. **Effective Date:** See Implementation Plan for ~~PRC-024-2~~ PRC-024-3

B. Requirements and Measures

R1. Each Generator Owner or Transmission Owner ~~that has generator frequency protective relaying[1] activated to trip its applicable generating unit(s)~~ shall set its applicable frequency protection ~~protective relaying~~ such that the ~~the generator frequency protective relaying~~generating resource does not trip or enter momentary cessation ~~the applicable generating unit(s)~~ within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions~~s~~[2]: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- ~~Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.~~
- ~~Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).~~
- Generating resource(s) ~~unit(s)~~ may be set to trip or enter momentary cessation within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner or Transmission Owner shall have evidence that the applicable frequency protection has ~~generator frequency protective relays have~~ been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner or Transmission Owner ~~that has generator voltage protective relaying[1] activated to trip its applicable generating unit(s)~~ shall set its ~~protective relaying~~applicable voltage protection such that the ~~generator voltage protective relaying~~generating resource does not trip or enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2~~the applicable generating unit(s) as a result of a~~ during a- voltage excursion at the high side of the GSU or collector transformer, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* ~~(at the point of interconnection[3]) caused by an event on the~~

~~[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.~~

~~[2] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.~~

~~transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.~~[4]

- If the Transmission Planner allows less stringent voltage ~~relay~~ protection settings than those required to meet PRC-024 Attachment 2, then the Generator Owner or Transmission Owner may ~~shall~~ set its protection ~~protective relaying~~ within the voltage recovery characteristics of a location-specific Transmission Planner's study. ~~Requirement R2 is subject to the following exceptions: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]~~

- ~~Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).~~

- ~~Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).~~

- ~~Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.~~

- Generating resource(s) ~~unit(s)~~ may trip or enter momentary cessation within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. Each Generator Owner or Transmission Owner shall have evidence that applicable ~~generator~~ voltage protection has~~protective relays have~~ been set in accordance with Requirement R2, such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

R3. Each Generator Owner or Transmission Owner shall document each known regulatory or equipment limitation[5] that prevents an applicable generating resource(s)~~unit~~ with generator frequency or voltage ~~protective relays~~protection from meeting the ~~relay~~ protection setting criteria in Requirements R1 or R2, including (but not limited to)

~~[3] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.~~

~~[4] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.~~

[5] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protection ~~protective relays themselves~~ itself but does not exclude limitations originating in the equipment that ~~they~~ it protects.

study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner or Transmission Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

M3. Each Generator Owner or Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations ~~(excluding limitations noted in footnote 3)~~ that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3, such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

R4. Each Generator Owner or Transmission Owner shall provide its applicable generator protection ~~trip~~ settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated generating resource(s) ~~unit~~ within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested ~~trip~~ settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of ~~relay~~ protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner or Transmission Owner shall have evidence that it communicated applicable generator ~~protective relay trip~~ protection settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

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 Generator Owner or Transmission Owner shall keep data or evidence of Requirements R1 through R4 for 3 years or until the next audit, whichever is longer.
- If a Generator Owner or Transmission Owner is found non-compliant, the Generator Owner or Transmission Owner shall keep information related to the non-compliance until mitigation is complete and approved 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Generator Owner or Transmission Owner ~~that has frequency protection activated to trip a generating unit,~~ failed to set its applicable ~~generator~~ frequency protection ~~protective relaying~~ so that it does not trip or enter momentary cessation ~~within the criteria listed in~~according to Requirement R1. ~~unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.~~
R2.	N/A	N/A	N/A	The Generator Owner or Transmission Owner ~~with voltage protective relaying activated to trip a generating unit,~~ failed to set its applicable voltage protection ~~protective relaying~~ so that it does not trip or enter momentary cessation ~~as a result of a voltage excursion~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~at the point of interconnection, caused by an event external to the plant per the criteria specified in~~according to Requirement R2.~~ unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.~~
R3.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	The Generator Owner or Transmission Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR The Generator Owner or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Transmission Planner within 120 calendar days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its generator protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its generator protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its generator protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner Transmission Owner failed to provide generator protection settings within 150 calendar days of a written request.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL

D. Regional Variances

D.A. Variance for the Quebec Interconnection

This Interconnection-wide Variance shall be applicable in the Quebec Interconnection and replaces~~,~~ in its entirety, continent-wide Requirement R2 with the following:

D.A.2. Each Generator Owner or Transmission Owner shall set its applicable voltage protection such that the generating resource does not trip or enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2a during a voltage excursion at the high side of the GSU or collector transformer, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2a, then the Generator Owner or Transmission Owner may set its protection~~-~~ within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Generating resource(s) may trip or enter momentary cessation within a portion of the "no trip zone" of PRC-024 Attachment 2a for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- Inverter-based resources voltage protection settings may be set to enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2a during a voltage excursion at the high side of the MPT under the following conditions:
  - After a minimum delay of 0.022 s, when the positive-sequence voltage exceeds 1.25 per unit (p.u.) Normal operation must resume once the voltage drops back below 1.25 p.u.
  - After a minimum delay of 0.022 s, when the phase-to-ground RMS voltages exceeds 1.4p.u., as measured at generator terminals, on one or multiple phases. Normal operation must resume once the voltage drops back below the 1.25 p.u.

M.D.A.2. Each Generator Owner or Transmission Owner shall have evidence that applicable voltage protection has been set in accordance with Requirement R2 such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

~~D.~~E. Associated Documents

Implementation Plan

Industry Recommendation I – Loss of Solar Resources during Transmission Disturbances Due to Inverter Settings

Industry Recommendation II – Loss of Solar Resources during Transmission Disturbances due to Inverter Settings

Blue Cut Fire Disturbance

Canyon 2 Fire Disturbance

"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

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"IEEE C50.13 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

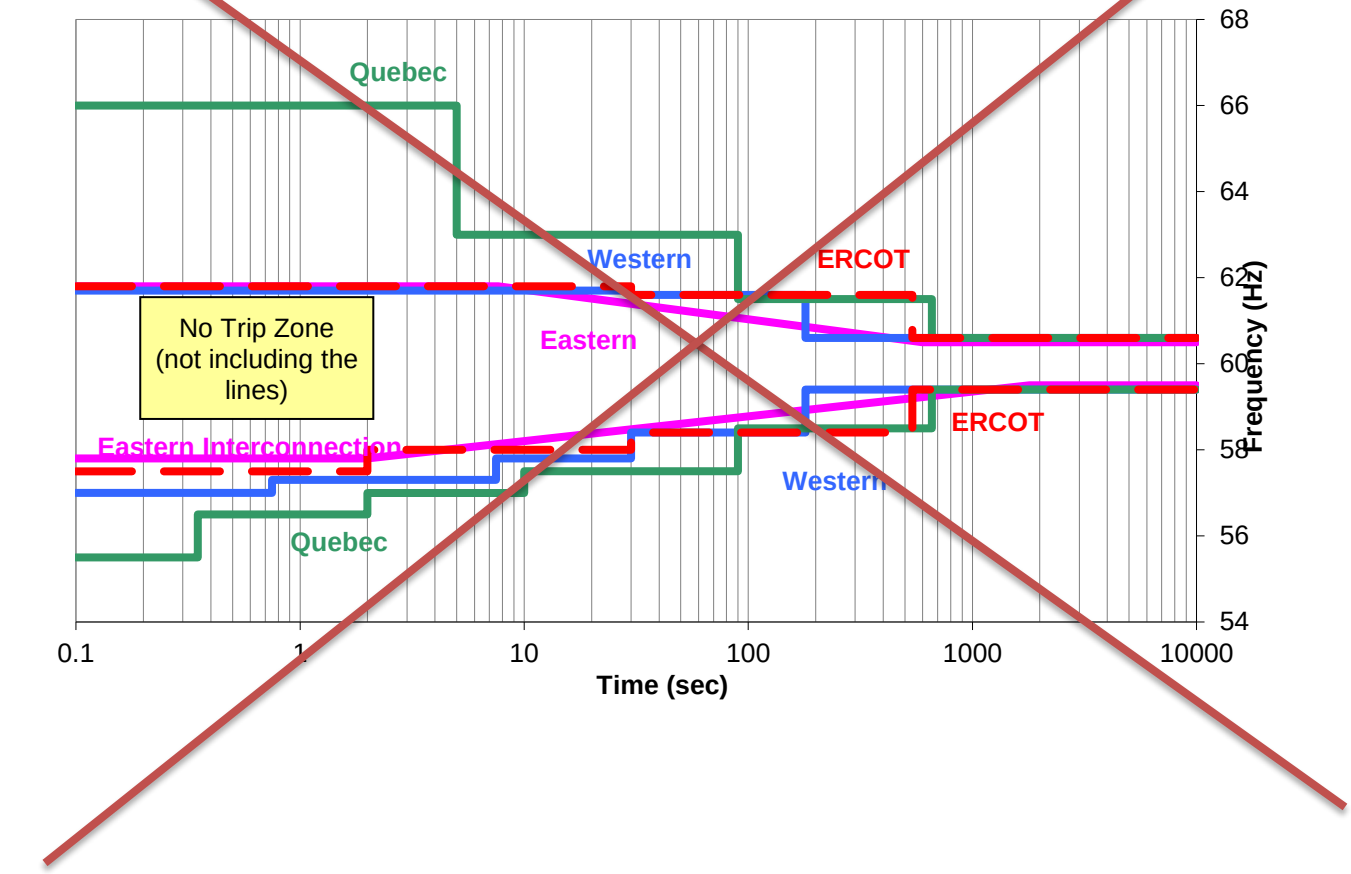
"IEEE C37.106 IEEE Guide for Abnormal Frequency Protection for Power Generating Plants"

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-024-2	Modifications to adjust the applicability to owners of dispersed generation resources.

PRC-024 — Attachment 1

~~OFF NOMINAL FREQUENCY CAPABILITY CURVE~~



Attachment 1

~~OFF NOMINAL FREQUENCY CAPABILITY CURVE~~

(Frequency No Trip Boundary by Interconnection)

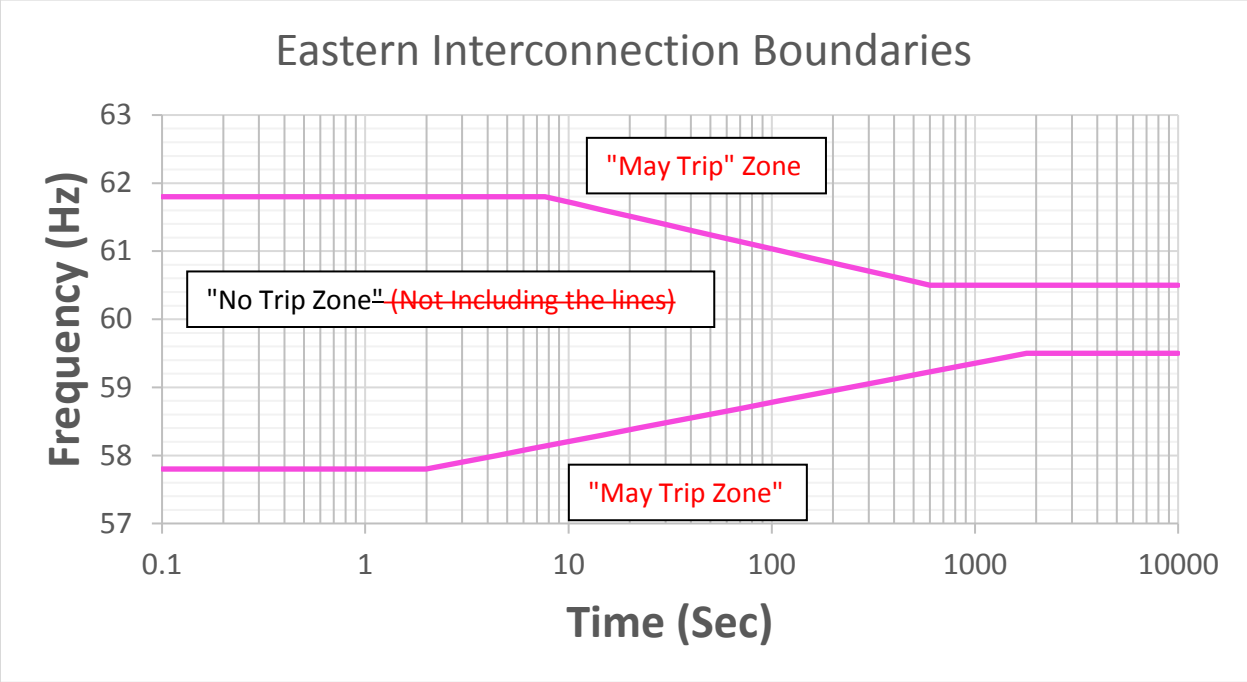


Figure 1

~~Curve~~ Frequency Boundary Data Points – Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	0.10~~Instantaneous trip~~	≤57.8	0.10~~Instantaneous trip~~
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Table 1

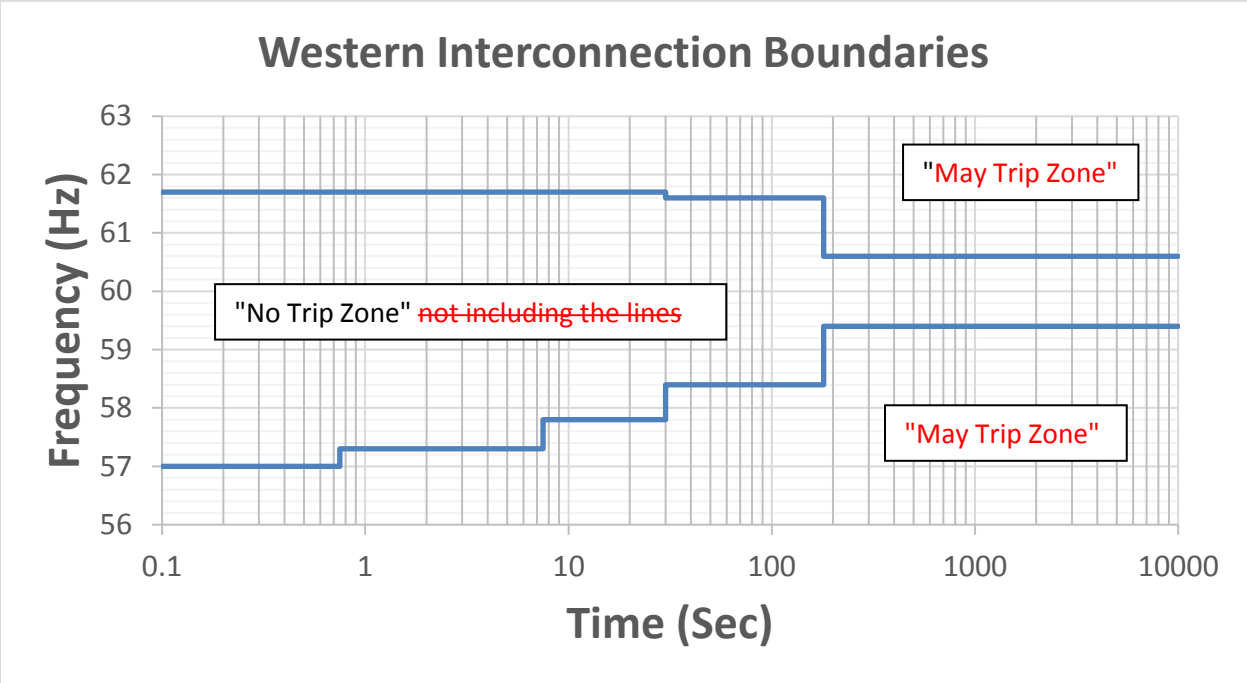


Figure 2

~~Curve~~Frequency~~-~~ Boundary Data Points – Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.7	0.10~~Instantaneous trip~~	≤57.0	0.10~~Instantaneous trip~~
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

Table 3

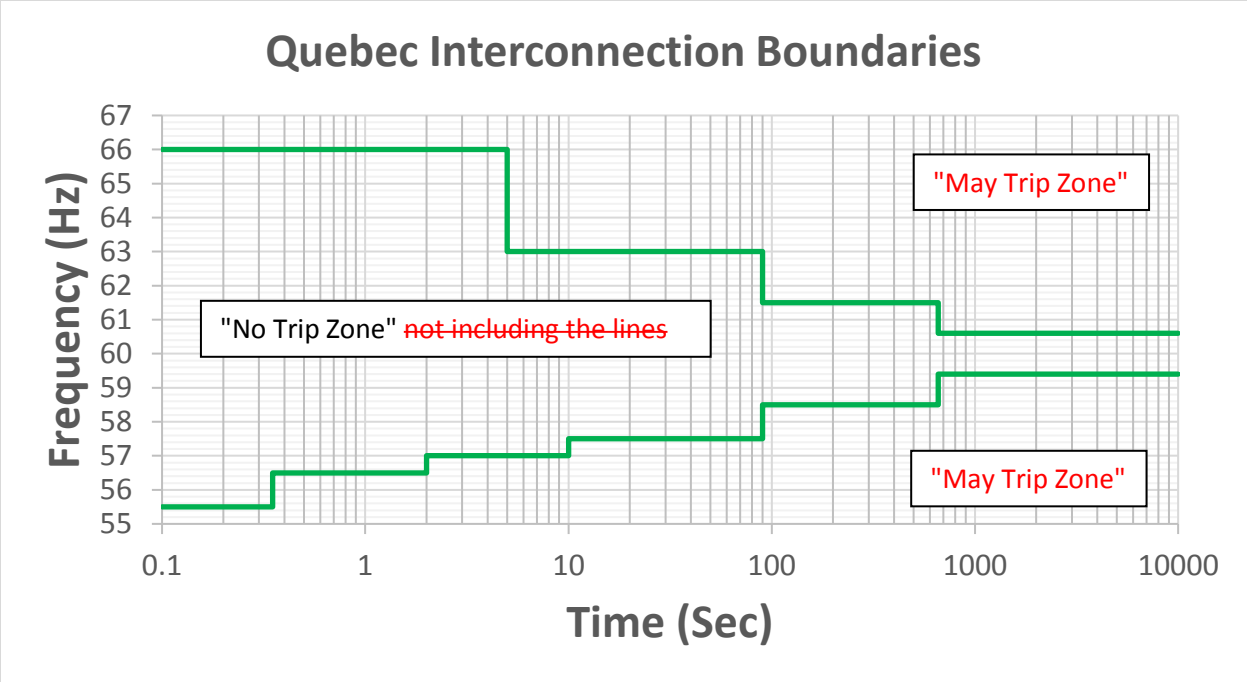


Figure 4

~~Curve~~ Frequency Boundary Data Points – Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (Sec)
>66.0	0.10~~Instantaneous trip~~	<55.5	0.10~~Instantaneous trip~~
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

Table 2

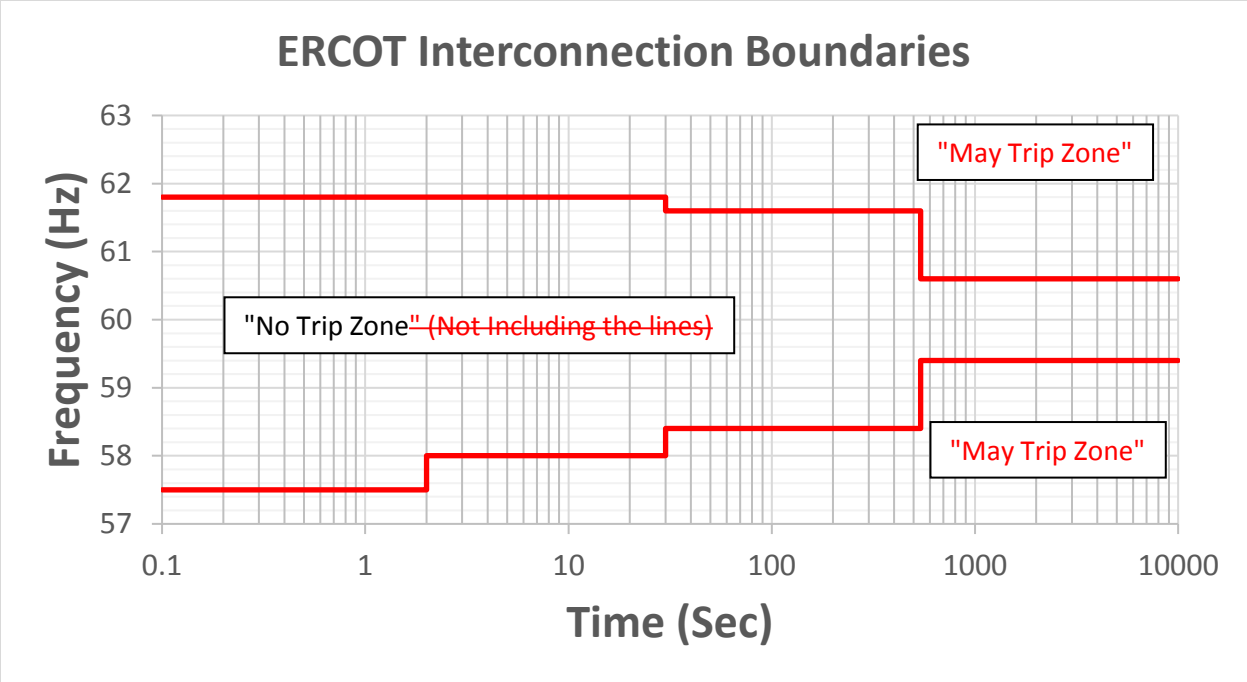


Figure 5

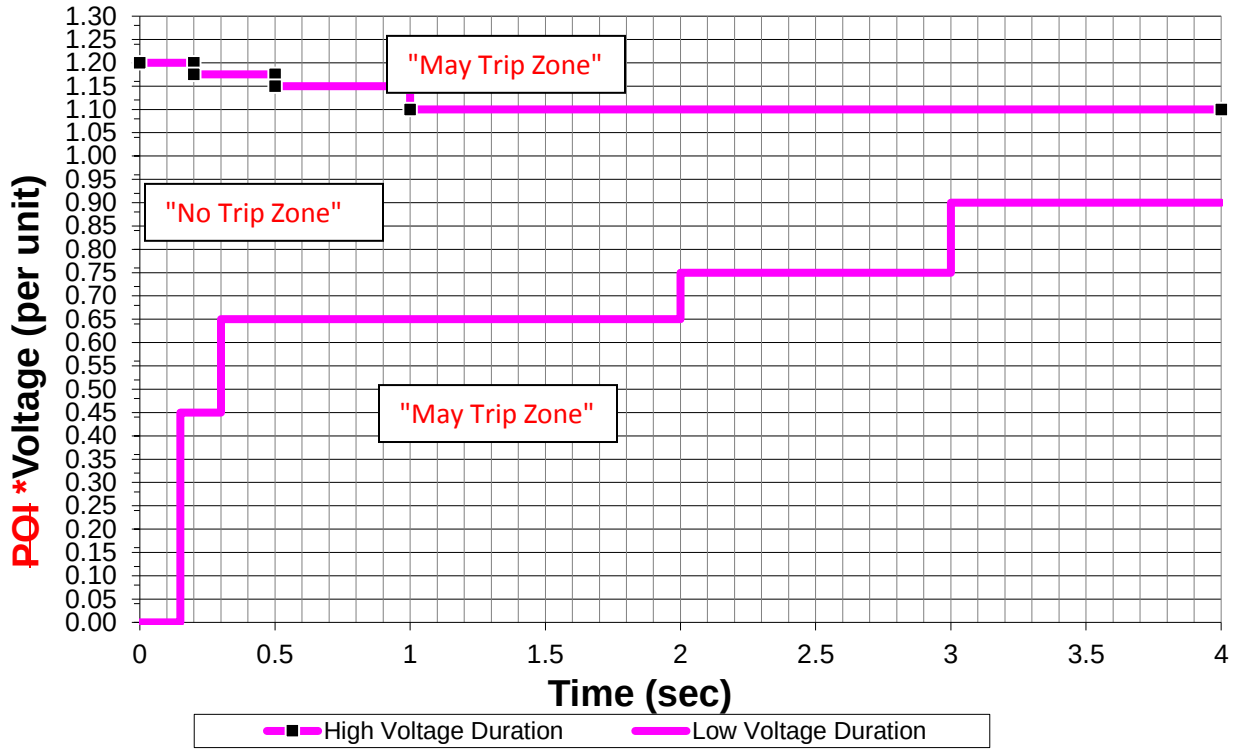
~~Curve~~ Frequency ~~-~~Boundary Data Points ~~–~~ ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	0.10~~Instantaneous trip~~	≤57.5	0.10~~Instantaneous trip~~
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

Table 3

PRC-024— Attachment 2

(Voltage No-Trip Boundary – Eastern, Western, and ERCOT Interconnections)



6

Figure 1

Voltage Boundary Data Points ~~Ride-Through Duration:~~

High Voltage ~~Ride-Through~~ Duration		Low Voltage ~~Ride-Through~~ Duration	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
≥1.200	~~Instantaneous trip~~0.00	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

*Voltage at the high-side of the GSU or collector transformer.

<1.10	4.00	≥ 0.90	4.00

Table 1
Voltage at the high-side of the GSU or collector transformer.

Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

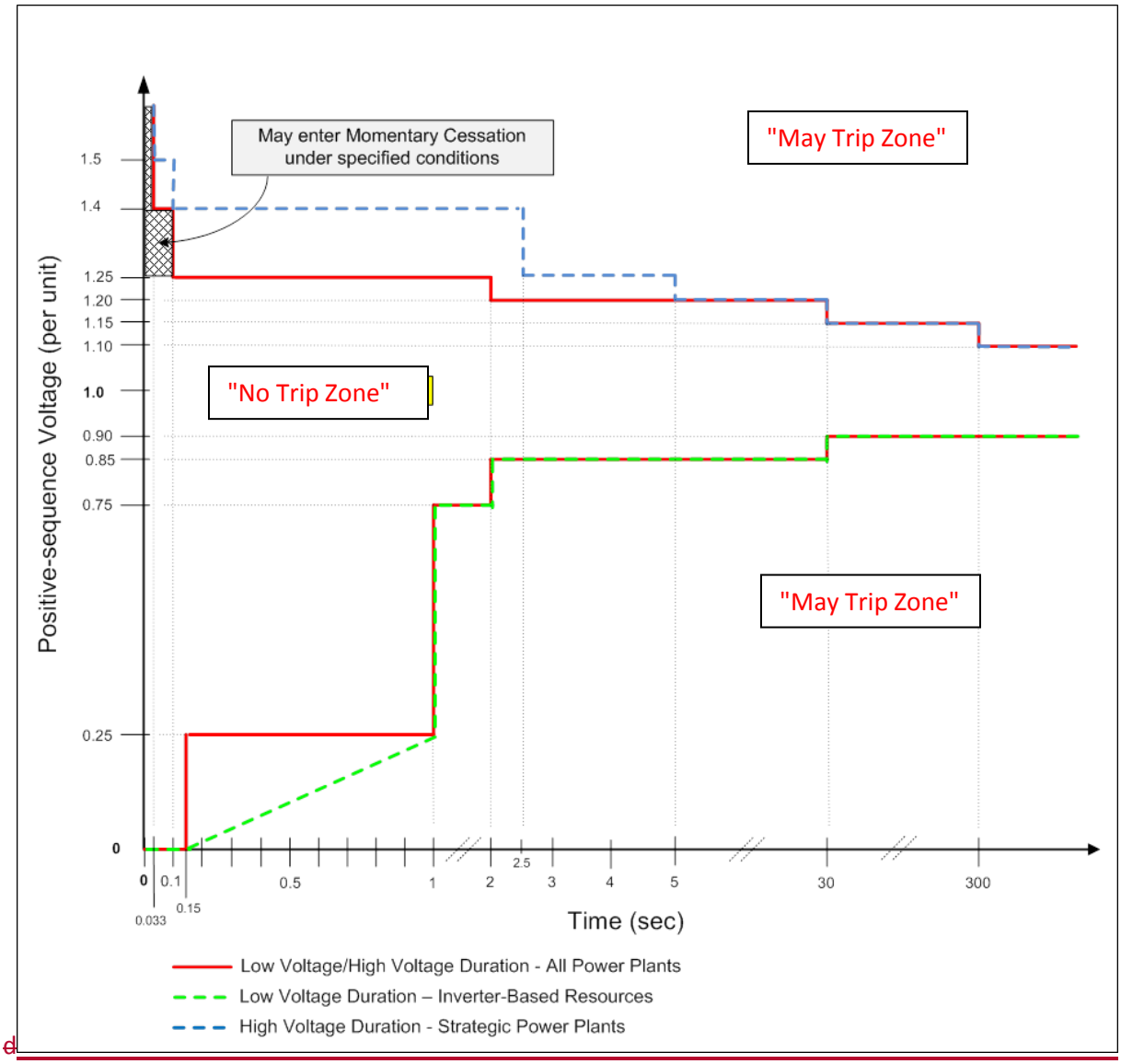
1. The per unit voltage base for these boundariescurves is the nominal operating voltage (e.g., 115 kV, 138 kV, 230 kV, 345 kV, 500 kV, etc.). specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The boundaries apply to voltage excursions regardless of the type of initiating event.
3. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The boundaries curves depicted assume a system frequency is of 60 Hertz. – When evaluating volts per hertzVolts/Hertz protection, you may adjust the magnitude of the high voltage curve boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
5. Voltages in the curve boundaries assume RMS minimum fundamental frequency phase-to-ground or phase-to-phase voltage. for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve
5.6. The “no trip zone” ends at 4 seconds.

Evaluating ProtectionProtective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection high

side of the GSU or collection transformer.

PRC-024— Attachment 2a
(Voltage No Trip Boundaries – Quebec Interconnection)



d

Figure 1a

Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Power Plants		High Voltage Duration for strategic[2] Power Plants	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
---	---	>1.50	0.033
>1.40	0.033	>1.40	0.10
>1.25	0.10	>1.25	2.50
>1.20	2.00	>1.20	5.00
>1.15	30	>1.15	30
>1.10	300	>1.10	300
≤1.10	continuous	≤1.10	continuous

Table 1a

Voltage Boundary Data Points – Quebec Interconnection

Low Voltage Duration for all Power Plants		Low Voltage Duration for Inverter-Based Resources	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
<0.25	0.15	<0.25	3.4*V(pu)+0.15
<0.75	1.00	<0.75	1.00
<0.85	2.00	<0.85	2.00
<0.90	30	<0.90	30
≥0.90	continuous	≥0.90	continuous

Table 2a

[1] Power Plants designated by the Transmission Planner for protecting the integrity of Transmission System equipment.

Voltage Boundary Clarifications – Quebec Interconnection

Boundary Details:

1. The per unit voltage base for these boundaries is the nominal operating voltage (e.g., 115 kV, 138 kV, 230 kV, 345 kV, 500 kV, etc.).
2. The boundaries apply to voltage excursions regardless of the type of initiating event.
3. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.
4. The boundaries assume a system frequency of 60 Hertz. When evaluating volts per hertz protection, magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
5. Voltages in the boundaries assume positive-sequence values.

Evaluating Protection Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection settings accounting for the actual tap settings of transformers between the generator terminals and the high side of the GSU or collector transformer.

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

PRC-024-3 is posted for a 45-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	December 2018
SAR posted for comment	December 19, 2018–January 19, 2019
Standards Committee accepted the revised SAR	February 20, 2019

Anticipated Actions	Date
45-day formal comment period with ballot	April – June 2019
45-day formal or informal comment period with additional ballot	July – August 2019
10-day final ballot	October 2019
Board adoption	November 2019

A. Introduction

1. **Title:** Generator Frequency and Voltage Protection Settings

2. **Number:** PRC-024-3

3. **Purpose:** To set generator protection, such that generating resource(s) remain connected, continuing to support the BES during defined frequency and voltage excursions.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owners that apply protection listed in Section 4.2.1.

   4.1.2. Transmission Owners that own a BES generator step-up (GSU) transformer or collector transformer and apply protection listed in Section 4.2.1.

   4.2. Facilities:

   4.2.1 Frequency, voltage or volts per hertz protection, including frequency or voltage protective functions within control systems that provide tripping or momentary cessation signals to all or part of the generating resource, applied to the following:

   4.2.1.1 Bulk Electric System (BES) generating resource(s).

   4.2.1.2 BES GSU transformer(s).

   4.2.1.3 High side of the generator-connected unit auxiliary transformer installed on BES generating resource(s).

   4.2.1.4 Individual dispersed power producing resources identified in the BES Definition, Inclusion I4.

   4.2.1.5 Elements utilized in aggregation of the dispersed power producing resources.

   4.2.1.6 Collector transformer of resources identified in the BES Definition, Inclusion I4.

5. **Effective Date:** See Implementation Plan for PRC-024-3

B. Requirements and Measures

R1. Each Generator Owner or Transmission Owner shall set its applicable frequency protection such that the generating resource does not trip or enter momentary cessation within the "no trip zone" of PRC-024 Attachment 1, subject to the following exception: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating resource(s) may be set to trip or enter momentary cessation within the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner or Transmission Owner shall have evidence that the applicable frequency protection has been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner or Transmission Owner shall set its applicable voltage protection such that the generating resource does not trip or enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2 during a voltage excursion at the high side of the GSU or collector transformer, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Generating resource(s) may trip or enter momentary cessation within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. Each Generator Owner or Transmission Owner shall have evidence that applicable voltage protection has been set in accordance with Requirement R2, such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

R3. Each Generator Owner or Transmission Owner shall document each known regulatory or equipment limitation[1] that prevents an applicable generating resource(s) with generator frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2, including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner or Transmission Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously

[1] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protection itself but does not exclude limitations originating in the equipment that it protects.

documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

M3. Each Generator Owner or Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3, such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

R4. Each Generator Owner or Transmission Owner shall provide its applicable generator protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated generating resource(s) within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner or Transmission Owner shall have evidence that it communicated applicable generator protection settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

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 Generator Owner or Transmission Owner shall keep data or evidence of Requirements R1 through R4 for 3 years or until the next audit, whichever is longer.
- If a Generator Owner or Transmission Owner is found non-compliant, the Generator Owner or Transmission Owner shall keep information related to the non-compliance until mitigation is complete and approved 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to set its applicable frequency protection so that it does not trip or enter momentary cessation according to Requirement R1.
R2.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to set its applicable voltage protection so that it does not trip or enter momentary cessation according to Requirement R2.
R3.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days	The Generator Owner or Transmission Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR The Generator Owner or Transmission Owner failed to communicate the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	but less than or equal to 60 calendar days of identifying the limitation.	but less than or equal to 90 calendar days of identifying the limitation.	but less than or equal to 120 calendar days of identifying the limitation.	documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its generator protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its generator protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its generator protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner failed to provide its generator protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide generator protection settings within 150 calendar days of a written request.

D. Regional Variances

D.A. Variance for the Quebec Interconnection

This Interconnection-wide Variance shall be applicable in the Quebec Interconnection and replaces, in its entirety, continent-wide Requirement R2 with the following:

D.A.2. Each Generator Owner or Transmission Owner shall set its applicable voltage protection such that the generating resource does not trip or enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2a during a voltage excursion at the high side of the GSU or collector transformer, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2a, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Generating resource(s) may trip or enter momentary cessation within a portion of the "no trip zone" of PRC-024 Attachment 2a for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- Inverter-based resources voltage protection settings may be set to enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2a during a voltage excursion at the high side of the MPT under the following conditions:
    - After a minimum delay of 0.022 s, when the positive-sequence voltage exceeds 1.25 per unit (p.u.) Normal operation must resume once the voltage drops back below 1.25 p.u.
    - After a minimum delay of 0.022 s, when the phase-to-ground root mean square (RMS) voltages exceeds 1.4 p.u., as measured at generator terminals, on one or multiple phases. Normal operation must resume once the voltage drops back below the 1.25 p.u.

M.D.A.2. Each Generator Owner or Transmission Owner shall have evidence that applicable voltage protection has been set in accordance with Requirement R2, such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

E. Associated Documents

Implementation Plan

Industry Recommendation I – Loss of Solar Resources during Transmission Disturbances Due to Inverter Settings

Industry Recommendation II – Loss of Solar Resources during Transmission Disturbances due to Inverter Settings

Blue Cut Fire Disturbance

Canyon 2 Fire Disturbance

“Protective Relaying For Power Generation Systems”, Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

“IEEE C37.102 IEEE Guide for AC Generator Protection”

“IEEE C50.13 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above”

“IEEE C37.106 IEEE Guide for Abnormal Frequency Protection for Power Generating Plants”

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2	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-024-2	Modifications to adjust the applicability to owners of dispersed generation resources.

Attachment 1
(Frequency No Trip Boundary by Interconnection)

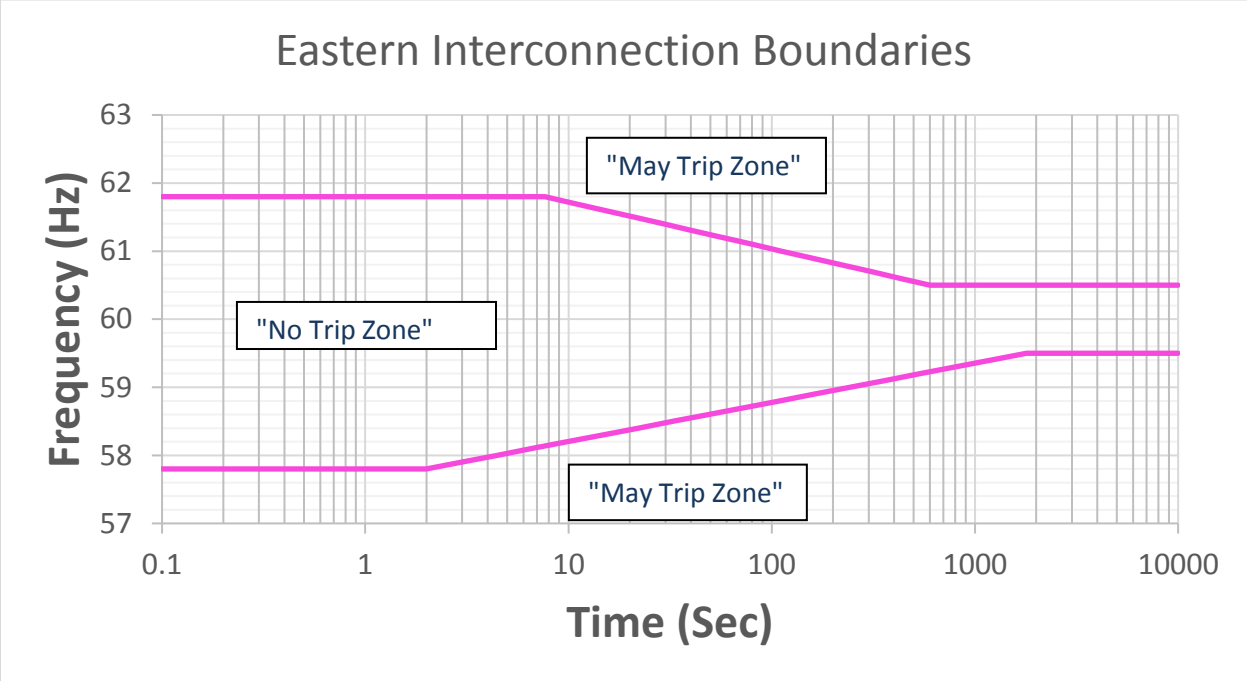


Figure 1

Frequency Boundary Data Points – Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.8	0.10	≤57.8	0.10
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Table 1

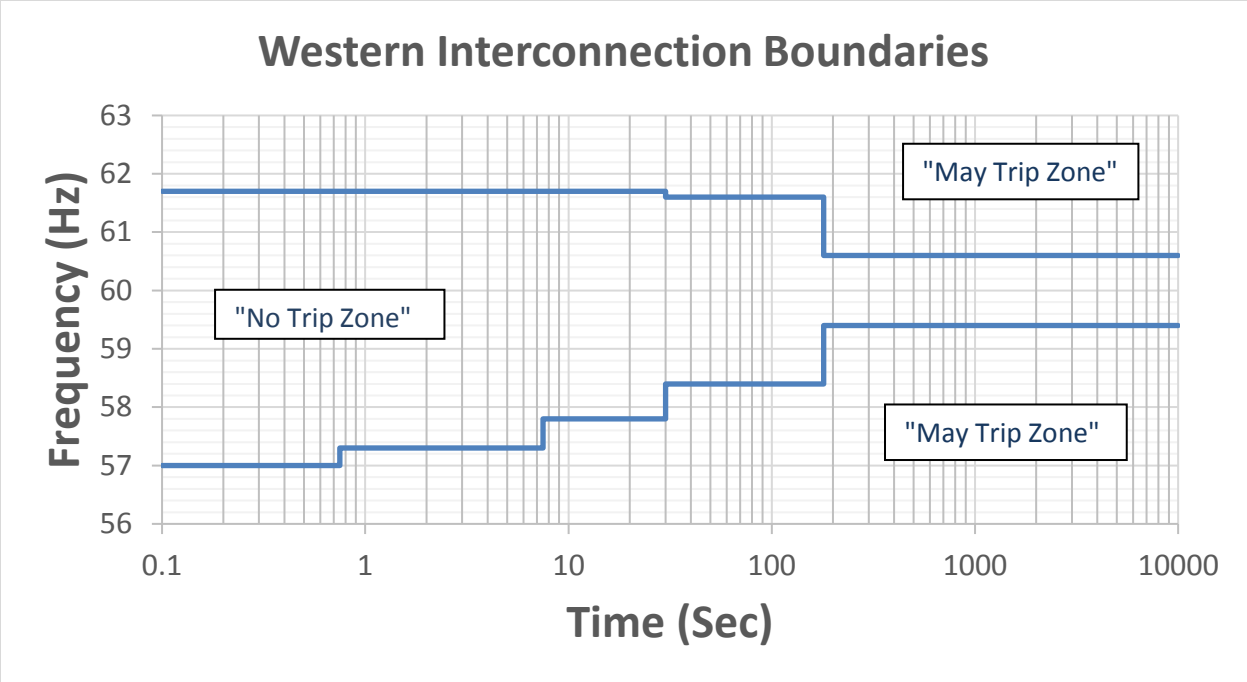


Figure 2

Frequency Boundary Data Points – Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.7	0.10	≤57.0	0.10
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

Table 3

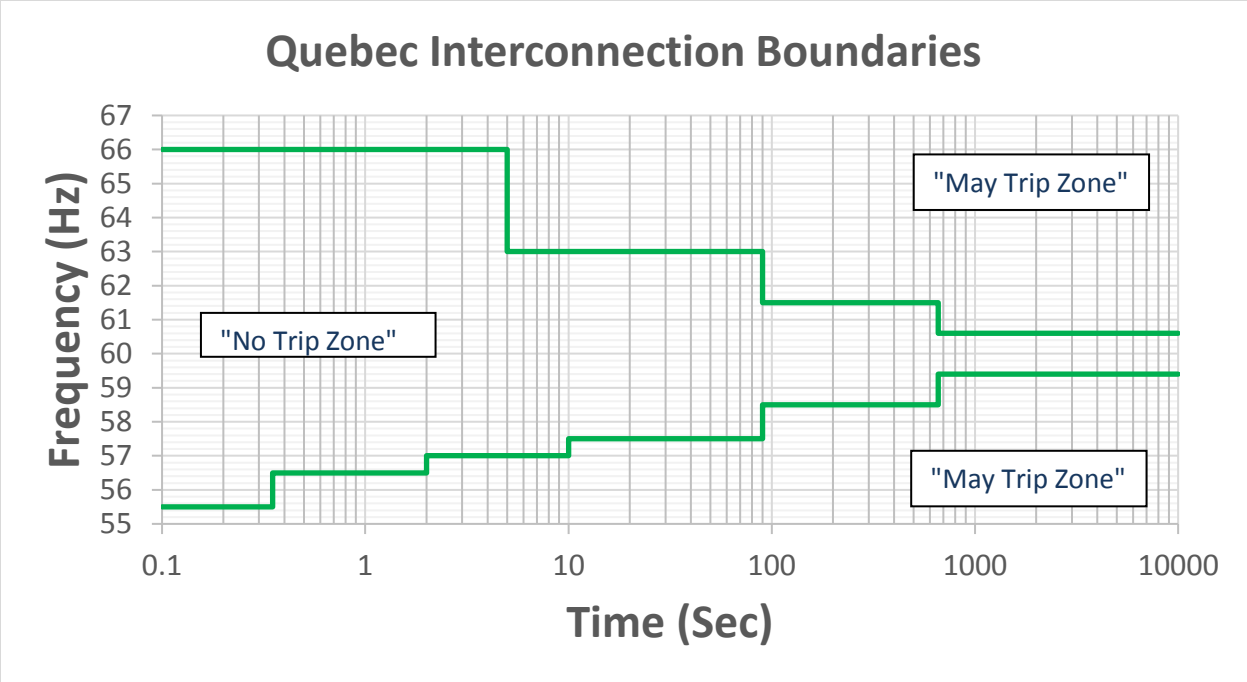


Figure 4

Frequency Boundary Data Points – Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (Sec)
>66.0	0.10	<55.5	0.10
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

Table 2

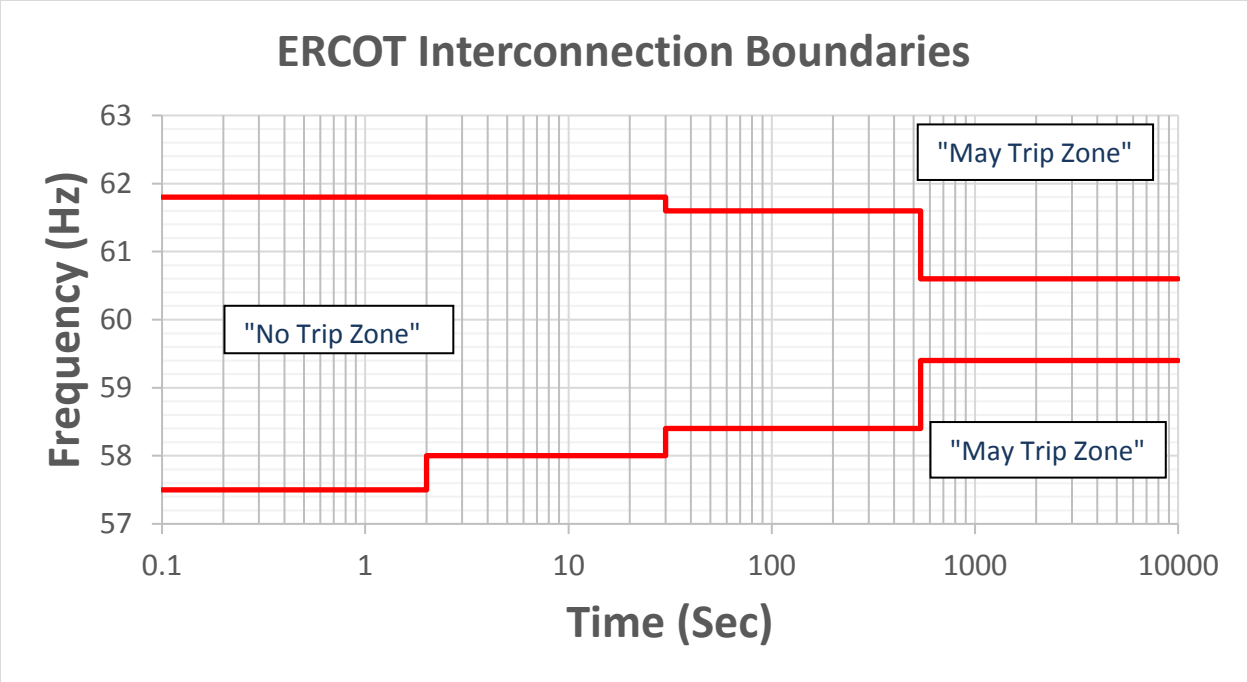


Figure 5

Frequency Boundary Data Points – ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	0.10	≤57.5	0.10
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

Table 3

PRC-024— Attachment 2

(Voltage No-Trip Boundary – Eastern, Western, and ERCOT Interconnections)

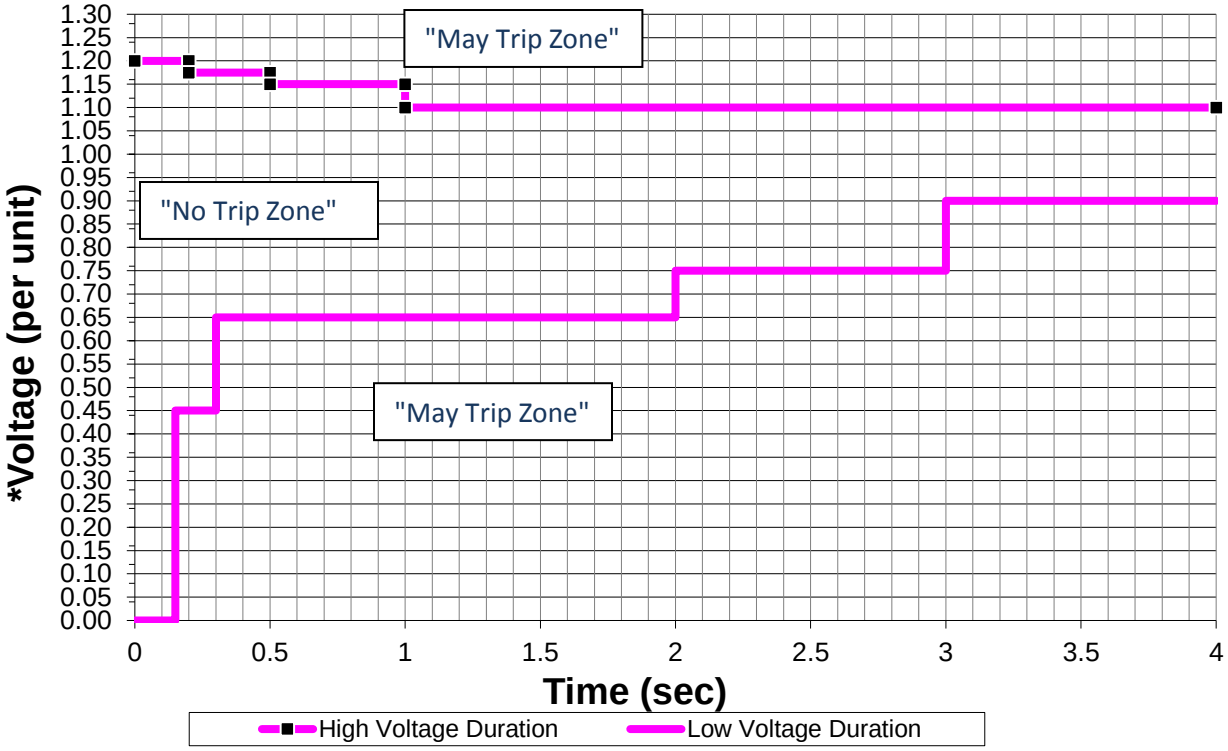


Figure 1

Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
≥1.200	0.00	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00
<1.10	4.00	≥ 0.90	4.00

Table 1

* Voltage at the high-side of the GSU or collector transformer.

Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. The per unit voltage base for these boundaries is the nominal operating voltage (e.g., 115 kV, 138 kV, 230 kV, 345 kV, 500 kV, etc.).
2. The boundaries apply to voltage excursions regardless of the type of initiating event.
3. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.
4. The boundaries assume a system frequency of 60 Hertz. When evaluating volts per hertz protection, magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
5. Voltages in the boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase voltage.
6. The “no trip zone” ends at 4 seconds.

Evaluating Protection Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection settings accounting for the actual tap settings of transformers between the generator terminals and the high side of the GSU or collector transformer.

PRC-024— Attachment 2a

(Voltage No Trip Boundaries – Quebec Interconnection)

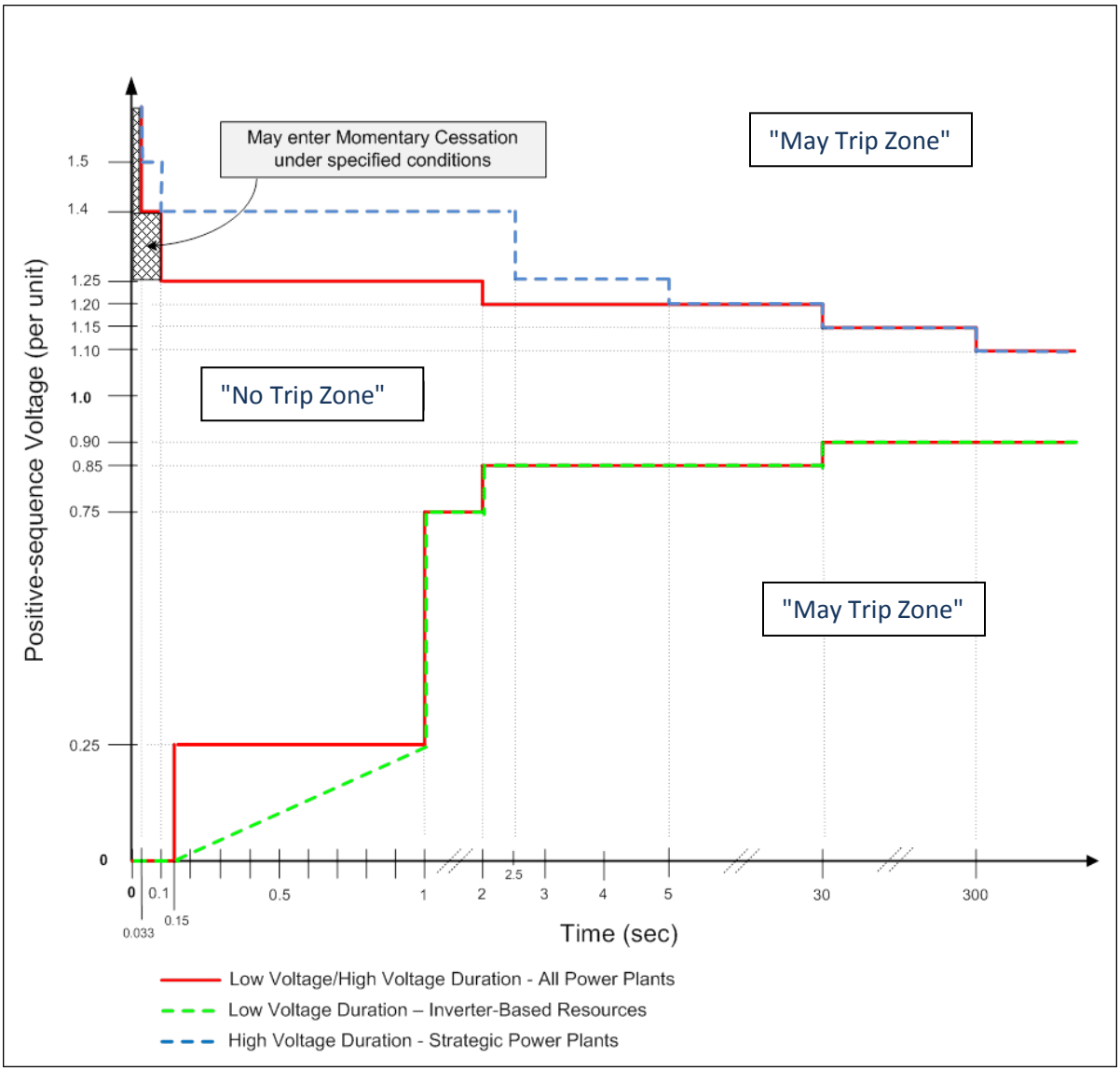


Figure 1

Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Power Plants		High Voltage Duration for strategic[1] Power Plants	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
---	---	>1.50	0.033
>1.40	0.033	>1.40	0.10
>1.25	0.10	>1.25	2.50
>1.20	2.00	>1.20	5.00
>1.15	30	>1.15	30
>1.10	300	>1.10	300
≤1.10	continuous	≤1.10	continuous

Table 1

Voltage Boundary Data Points – Quebec Interconnection

Low Voltage Duration for all Power Plants		Low Voltage Duration for Inverter-Based Resources	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
<0.25	0.15	<0.25	3.4*V(pu)+0.15
<0.75	1.00	<0.75	1.00
<0.85	2.00	<0.85	2.00
<0.90	30	<0.90	30
≥0.90	continuous	≥0.90	continuous

Table 2

[1] Power Plants designated by the Transmission Planner for protecting the integrity of Transmission System equipment.

Voltage Boundary Clarifications – Quebec Interconnection

Boundary Details:

1. The per unit voltage base for these boundaries is the nominal operating voltage (e.g., 115 kV, 138 kV, 230 kV, 345 kV, 500 kV, etc.).
2. The boundaries apply to voltage excursions regardless of the type of initiating event.
3. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.
4. The boundaries assume a system frequency of 60 Hertz. When evaluating volts per hertz protection, magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
5. Voltages in the boundaries assume positive-sequence values.

Evaluating Protection Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection settings accounting for the actual tap settings of transformers between the generator terminals and the high side of the GSU or collector transformer.

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Standard Authorization Request (SAR)

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

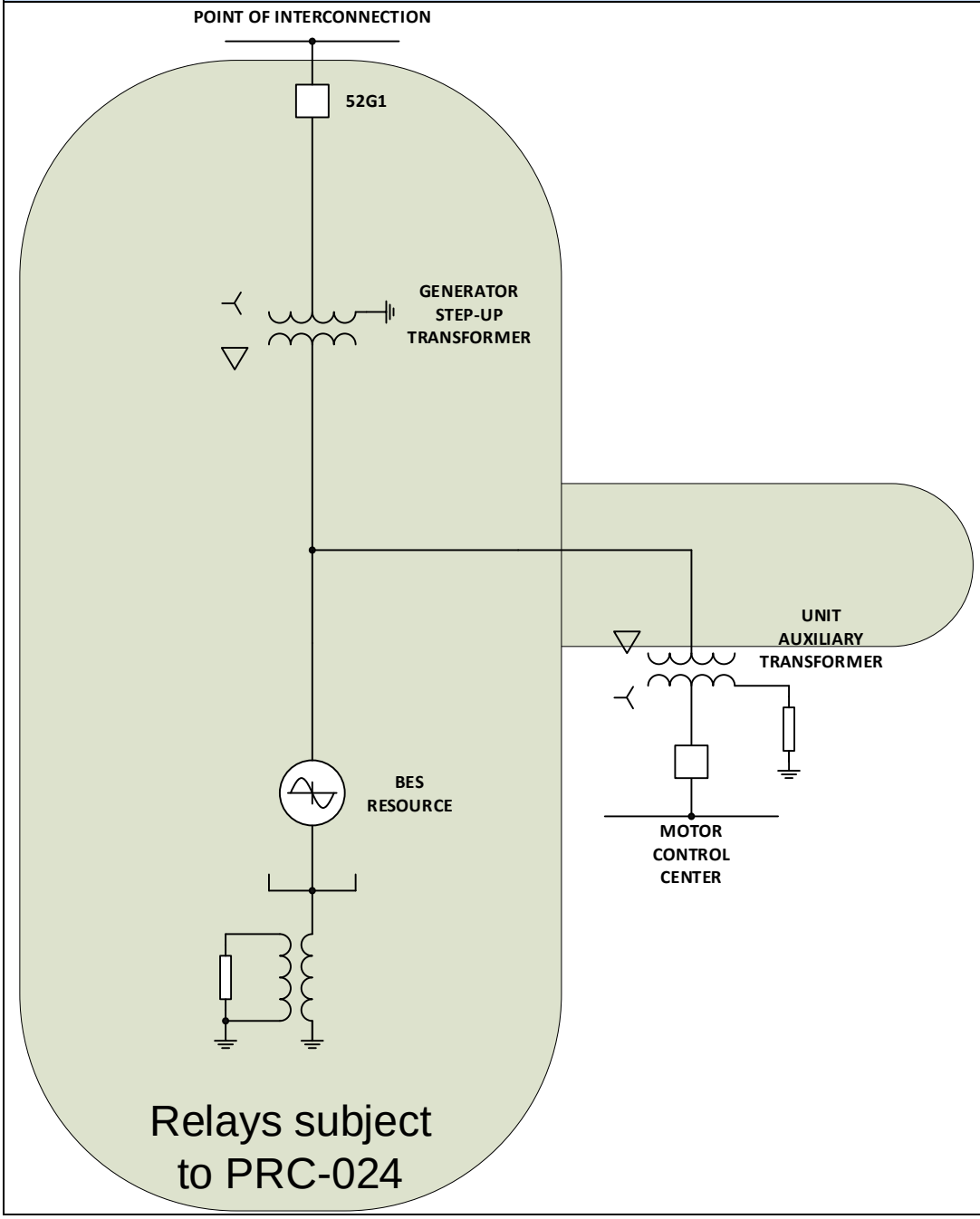
The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Supplemental SAR for Project 2018-04 Modifications to PRC-024-2		
Date Submitted:	6/14/2019		
SAR Requester			
Name:	Jason Espinosa		
Organization:	Seminole Electric Cooperative, Inc.		
Telephone:	321-604-8619	Email:	jespinosa@seminole-electric.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?):			
During its discussions, the SDT identified two issues within PRC-024 that must be addressed to ensure the reliability intent of the standard is achieved. 1. In the currently enforceable standard, Requirements R1 and R2 refer only to "generator protective relaying" which seems to exclude the setting of voltage and frequency protection relays on the Generator Step-Up Transformer (GSU) associated with synchronous generators. Because the GSU and the generator are connected to the same bus and have the same source (the generator), they see the same voltage (and frequency). Consequently, the voltage and frequency protection settings applied to the relays on the GSU must be included in the standard as the operation of those relays would result in tripping the generator. Note: This situation does not exist in the standard for dispersed power producing resources because the associated collector transformer and its voltage and frequency protection is included via Inclusion I4 of the BES definition and in the standard through footnotes 2, 3, and 4.			

Requested information
2. The existing standard is applicable only to Generator Owners which excludes instances where the Transmission Owner is the Registered Entity that owns the GSU or collector transformer and the associated voltage and frequency protective relays. The Supplemental SAR expands the scope of the project to eliminate the identified reliability issues by: (1) requiring all voltage and frequency protection up to the point of interconnection (the high voltage side of the GSU or collector transformer) to adhere to the voltage and frequency boundary curves of PRC-024, and (2) requiring those Transmission Owners that own the GSU or collector transformer and the associated voltage and frequency protective relays to be compliant with the standard. Closing these gaps increases reliability by ensuring all of the Registered Entities and facilities relevant to achieving the reliability intent of this standard are included in the Applicability Section and requirement language of the revised standard.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
Ensure the voltage and frequency protection on all applicable equipment (including the GSU or collector transformer) up to the point of interconnection that could cause a generating resource to trip or cease to inject current meets the voltage and frequency ride-through requirements of PRC-024, thus enabling the generating resource to support grid stability during defined system voltage and frequency excursions.
Project Scope (Define the parameters of the proposed project):
Revise the Applicability to include all relevant Registered Entities and facilities to make the standard more comprehensive, and revise the requirement language to improve the clarity and completeness of the standard.

Requested information

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



[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
Referring to the figure above, all voltage and frequency protection relays in the shaded area would not be considered "generator protective relaying" and would therefore not be subject to the existing PRC-024-2 standard. However, the operation of any of these voltage and frequency protections results in the disconnection of the generating resource. If these relays are getting their voltage and frequency inputs from the terminals of the generator, then they are seeing the same voltage and frequency as the "generator protective relaying". Because the generator, GSU, and Unit Auxiliary Transformer (UAT) all see the same voltage and frequency since they are connected to the same bus (the generator being the source), the settings applied to the voltage and frequency protection on the GSU and the high side of the UAT must also comply with the PRC-024 frequency and voltage curves to ensure the generator remains connected during defined frequency and voltage excursions. To avoid having to comply with PRC-024, an entity could remove (disable) the voltage and frequency protective functionality from the "generator protective relaying" and place it (enable) in either the GSU or UAT protection. Alternatively, an entity could enable voltage protective functions in both the "generator protective relaying" and the GSU relaying. If the generator voltage protective function is set outside of the no trip zone and the GSU relay voltage protective function is set within the no trip zone; then for a voltage excursion condition (within the no trip zone), the generator protection would not initiate a trip but the GSU relay would initiate a trip. This would not qualify as a violation of PRC-024 according to the existing language but it would conflict with the intent of the standard since the generation would be taken off-line without the generator protection initiating the trip. The SDT asserts that all frequency and voltage protective functions from the generator up to the point of interconnection should have to comply with the requirements of PRC-024. This would ensure the reliability intent of the standard is achieved, enabling the generator to ride through defined frequency and voltage excursions at the point of interconnection.

Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.* Dispersed Generation Resources):
Frequency and voltage protective functions on GSUs/collector transformers owned by transmission entities, synchronous generation, and inverter-based resources may be impacted by the revisions.
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 Generator Owners and only those Transmission Owners that own a GSU or collector transformer and associated voltage and frequency protection.

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.
Project 2018-04 Modifications to PRC-024-2
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
No
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
No

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
None	None

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

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PRC-024-3 – Summary of Key Changes

Project 2018-04 Modifications to PRC-024-2

Momentary Cessation

- Requirements R1 and R2 modified to specify that a generating resource may neither trip NOR enter momentary cessation inside the No Trip Zone

No Trip Zone

- To clarify confusion regarding tripping or entering momentary cessation *outside* the No Trip Zone, the area outside the boundary is now labeled as a "May Trip Zone"

Applicability Section

- Facilities Section added that explicitly lists protective functions for specific equipment
  - Plant Auxiliary Equipment is not included as an applicable facility
  - Specifies that voltage and frequency protection should be applied to both generator step-up (GSU) and collector transformers
  - Addresses a potential reliability gap identified by the standard drafting team
    - Some Transmission Owners (TOs) own GSU or collector transformers, yet are not currently in scope PRC-024

Inclusion of Some TOs as Functional Entities[1]

- *Not all TOs are applicable*
- Only those specific TOs that own a GSU or collector transformer and apply protection listed in the facilities section are now in scope of PRC-024

Point of Interconnection (POI)

- To address ambiguity concerns, removed the term altogether and replaced with precise language for this standard:

[1] Requirements R1 and R2 in the currently enforceable PRC-024-2 standard, via footnotes 2 and 4, include all frequency and voltage protective relays from the individual generating resource to the high side of the main power transformer for dispersed power producing resources. There was also an identified potential reliability gap when frequency and voltage protection, specifically volts per hertz, are applied to conventional generator GSUs. To alleviate this potential reliability gap, and to achieve parity for all resources, the SDT added a facilities section to specify the facilities that are subject to the Standard, if those facilities have frequency and voltage protection enabled. The facilities section now clarifies that the GSU or collector transformer is an applicable facility.

- "at the high side of the GSU or collector transformer"

Figures and Tables

- Clarified areas of confusion as specified by the Standard Authorization Request
- General "clean up" work throughout

Variance – Quebec Interconnection

- Variance to Requirement R2 with more stringent under/over voltage boundaries

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Violation Risk Factor and Violation Severity Level Justification

Project 2018-04 Modifications to PRC-024-2 April 2019

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard PRC-024-3. 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.

Justification for PRC-024-3 VRFs and VSLs

VRF Justification for PRC-024-3, Requirement R1

The VRF did not change from the previously FERC-approved PRC-024-2 Reliability Standard.

VSL Justification for PRC-024-3, Requirement R1

The SDT only made changes to conform the Requirement R1 VSL to the revised Requirement R1 language. The SDT retained the binary structure of the VSL, which is consistent with both the PRC-024-2 and PRC-024-1 VSLs. As a result, the justification for the Commission-approved PRC-024-1 Requirement R1 VSL supports the justification for the proposed PRC-024-3, Requirement R1 VSL.

VRF Justification for PRC-024-3, Requirement R2

The VRF did not change from the previously FERC-approved PRC-024-2 Reliability Standard.

VSL Justification for PRC-024-3, Requirement R2

The SDT only made changes to conform the Requirement R2 VSL to the revised Requirement R2 language. The SDT retained the binary structure of the VSL, which is consistent with both the PRC-024-2 and PRC-024-1 VSLs. As a result, the justification for the Commission-approved PRC-024-1 Requirement R2 VSL supports the justification for the proposed PRC-024-3, Requirement R2 VSL.

VRF Justification for PRC-024-3, Requirement R3

The VRF did not change from the previously FERC-approved PRC-024-2 Reliability Standard.

VSL Justification for PRC-024-3, Requirement R3

The SDT only revised the Requirement R3 VSL to add Transmission Owner. The SDT retained the existing levels of the VSLs, which is consistent with both the PRC-024-2 and PRC-024-1 VSLs. As a result, the justification for the Commission-approved PRC-024-1 Requirement R3 VSL supports the justification for the proposed PRC-024-3, Requirement R3 VSL.

VRF Justification for PRC-024-3, Requirement R4

The VRF did not change from the previously FERC-approved PRC-024-2 Reliability Standard.

VSL Justification for PRC-024-3, Requirement R4

The SDT only revised the Requirement R4 VSL to add Transmission Owner. The SDT retained the existing levels of the VSLs, which is consistent with both the PRC-024-2 and PRC-024-1 VSLs. As a result, the justification for the Commission-approved PRC-024-1 Requirement R4 VSL supports the justification for the proposed PRC-024-3, Requirement R4 VSL.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2018-04 Modifications to PRC-024-2
Reliability Standard PRC-024-3

Applicable Standard

- Reliability Standard PRC-024-3 – Generator Frequency and Voltage Protection Settings

Requested Retirement

- Reliability Standard PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

Prerequisite Standard(s)

- None

Applicable Entities

- Generator Owners that apply protection listed in Section 4.2.1.
- Transmission Owners that own a BES generator step-up transformer or collector transformer and apply protection listed in Section 4.2.1.

Background

On November 27, 2018, the NERC Operating Committee (OC) and Planning Committee (PC) submitted a Standard Authorization Request (SAR) prepared by the Inverter-Based Resource Performance Task Force (IRPTF), which reports to the OC and PC. Project 2018-04 addresses this SAR.

In 2017, the OC and PC convened the IRPTF shortly after it became clear that inverter-based generation was dropping off-line during normally cleared Bulk Power System (BPS) line faults. The NERC IRPTF supported NERC and WECC staff in the analysis of the Blue Cut Fire and Canyon 2 Fire disturbances in southern California. From the key findings and recommendations in the reports on the analysis, the IRPTF (as a stakeholder group of industry experts) developed recommended performance characteristics from inverter-based resources connected to the BPS.

Based off the disturbance analyses and development of the PRC-024-2 Gaps Whitepaper, the IRPTF identified potential modifications to PRC-024-2 to help ensure that inverter-based generator owners, operators, developers, and equipment manufacturers understand the intent of the standard in order for their plants respond to grid disturbances in a manner that contributes to the reliable operation of the BPS.

General Considerations

This Implementation Plan includes an effective date as well as phased-in compliance dates. As detailed below, there are two compliance dates: one for Generator Owners and one for Transmission Owners.

Effective Date

Reliability Standard PRC-024-3

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 eighteen (18) 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 eighteen (18) 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 Applicable Generator Owners

Applicable Generator Owners shall comply with all Requirements upon the effective date of Reliability Standard PRC-024-3.

Compliance Date for Applicable Transmission Owners

Applicable Transmission Owners shall not be required to comply with the Requirements until forty-two (42) months after the effective date of Reliability Standard PRC-024-3.

Retirement Date

Reliability Standard PRC-024-2

Reliability Standard PRC-024-2 shall be retired immediately prior to the effective date of Reliability Standard PRC-024-3 in the particular jurisdiction in which the revised standard is becoming effective.

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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first draft of proposed standard for formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 20, 2019
SAR posted for comment	February 25 – March 27, 2019

Anticipated Actions	Date
45-day formal comment period with ballot	July – September 2019
45-day formal comment period with additional ballot	October – December 2019
45-day formal comment period with second additional ballot	January – March 2020
10-day final ballot	April 2020
Board adoption	May 2020

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A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events

2. **Number:** TPL-007-4

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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-007-4

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6. **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.

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Deleted: 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 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]*

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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.

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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.

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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

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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 ERO approval for any extension sought under Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

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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 submitted to the ERO with a request for extension if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following:

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7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

7.4.2. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable; and

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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. Updated timetable for implementing the selected actions in Part 7.1.

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.

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7.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

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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 submitted a request for extension to the ERO if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. 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.

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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.

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8.3. 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.

8.3.1. 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.

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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 Assessment: (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.

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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.

R11. Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1, shall develop a Corrective

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Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

11.1. 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.

11.2. Be developed within one year of completion of the supplemental GMD Vulnerability Assessment.

11.3. Include a timetable, subject to ERO approval for any extension sought under Part 11.4, for implementing the selected actions from Part 11.1. The timetable shall:

11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

11.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

11.4. Be submitted to the ERO with a request for extension if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. The submitted CAP shall document the following:

11.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures, if applicable; and

11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

11.5. 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.

11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

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M11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental 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 R11. 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 submitted a request for extension to the ERO if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. 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 R11. 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 R11.

GMD Measurement Data Processes

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R12. 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]*

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M12. 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 R12.

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R13. 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]*

M13. 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 R13.

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C. Compliance

1. Compliance Monitoring Process

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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 and R11, 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 R12 and R13, each responsible entity shall retain documentation as evidence for three years.

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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.

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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

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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.

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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

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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

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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

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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 develop a Corrective Action Plan as required by Requirement R7.
R8.	The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R8, Parts 8.1 through 8.3; 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 the elements listed in Requirement R8, Parts 8.1 through 8.3; 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 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more

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R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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

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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

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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.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.

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R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12.	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.
R13.	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.

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D. Regional Variances

D.A. Regional Variance for Canadian Jurisdictions

This Variance shall be applicable in those Canadian jurisdictions where the Variance has been approved for use by the applicable governmental authority or has otherwise become effective in the jurisdiction.

This variance replaces all references to "Attachment 1" in the standard with "Attachment 1 or Attachment 1-CAN."

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In addition, this Variance replaces Requirement R7, Part 7.3 through Part 7.5 and Requirement R11, Part 11.3 through Part 11.5 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part D.A.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

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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.

D.A.7.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.7.3. The revised CAP shall document the following:

D.A.7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

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D.A.7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable; and

D.A.7.4.3 Updated timetable for implementing the selected actions in Part 7.1.

D.A.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, (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, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision.

D.A.7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

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D.A.M.7. 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, (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, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision. 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.

D.A.11.3. Include a timetable, subject to revision by the responsible entity in Part D.A.11.4, for implementing the selected actions from Part 11.1. The timetable shall:

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D.A.11.3.1. 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.11.3.2. 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.

D.A.11.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.11.3. The revised CAP shall document the following:

D.A.11.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

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D.A.11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures if applicable; and

D.A.11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

D.A.11.5. 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, (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, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision.

D.A.11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

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D.A.M.11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental 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 R11. 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, (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 R11, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision. 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 R11.

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E. Associated Documents

Attachment 1

Attachment 1-CAN

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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.
2	November 25, 2018	FERC Order issued approving TPL-007-2. Docket No. RM18-8-000	
3	February 7, 2019	Adopted by the NERC Board of Trustees	Canadian Variance
4	TBD	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order. 851

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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.

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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.

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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.

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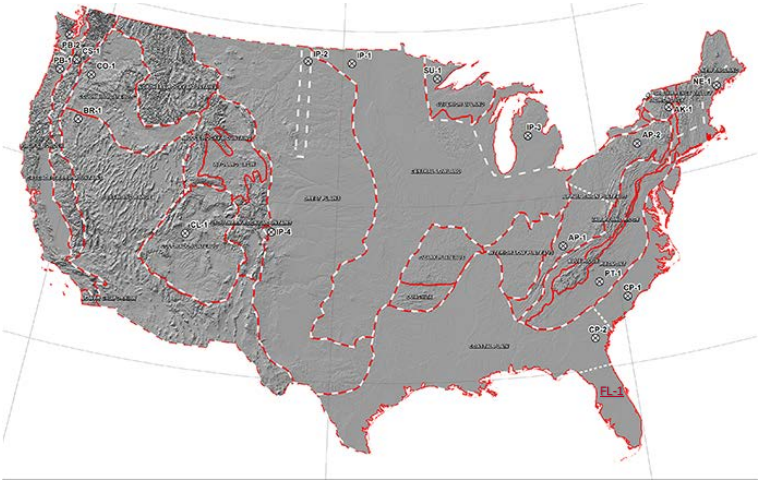


Figure 1: Physiographic Regions of the Continental United States[6]



Figure 2: Physiographic Regions of Canada

[6] Additional map detail is available at the U.S. Geological Survey: http://geomag.usgs.gov/.

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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

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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.

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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.

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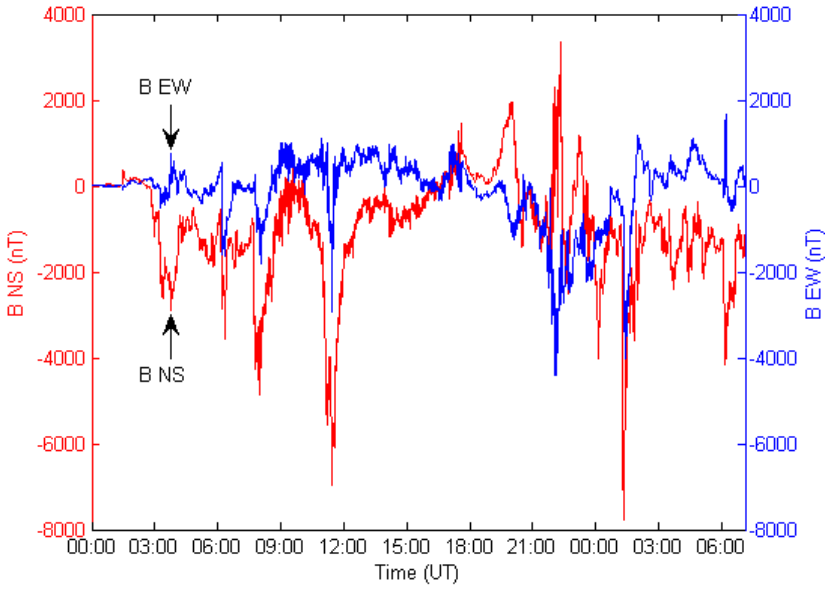


Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

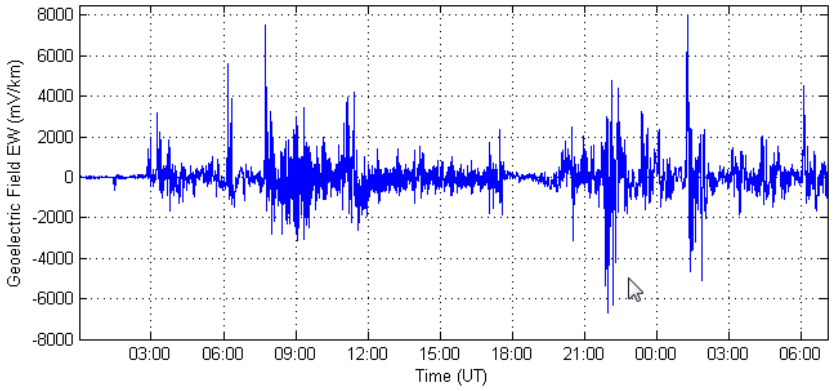


Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

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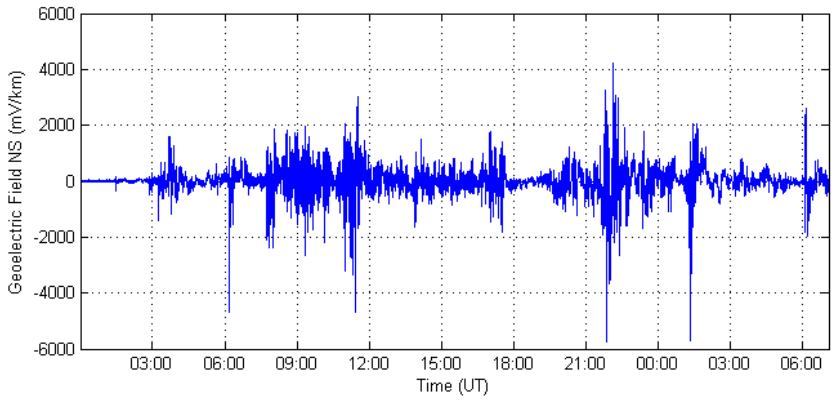


Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

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.

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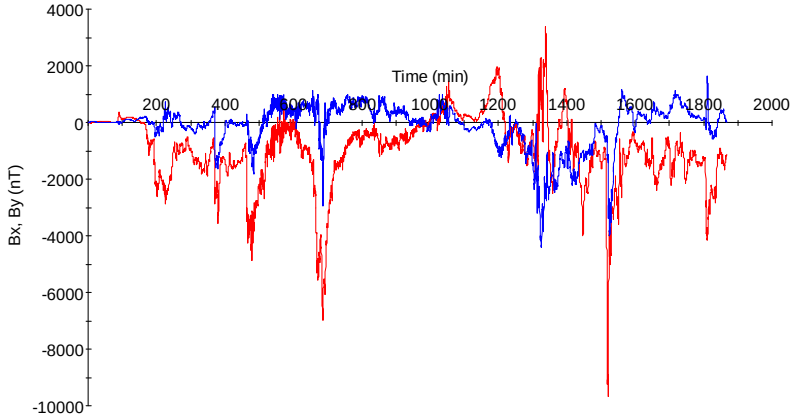


Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

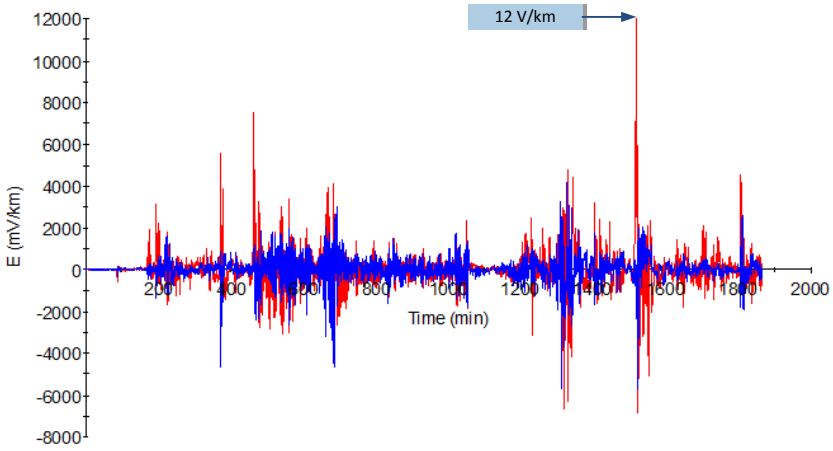


Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

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Attachment 1-CAN provides an alternative that a 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.

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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 entity shall consider the small-scale spatial structure of the GMD event (e.g., using magnetometer measurements or realistic electrojet calculations).

[1] The "earth transfer function" is the relationship between the electric fields and magnetic field variations at the surface of the earth.

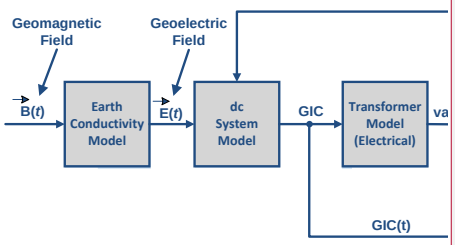
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Guidelines and Technical Basis¶

Guidelines and Technical Basis¶

The diagram below provides an overall view of the GMD Vulnerability Assessment process:¶



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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first draft of proposed standard for formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 20, 2019
SAR posted for comment	February 25 – March 27, 2019

Anticipated Actions	Date
45-day formal comment period with ballot	July – September 2019
45-day formal comment period with additional ballot	October – December 2019
45-day formal comment period with second additional ballot	January – March 2020
10-day final ballot	April 2020
Board adoption	May 2020

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events

2. **Number:** TPL-007-4

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-007-4.

6. **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.

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 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 ERO approval for any extension sought under 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 submitted to the ERO with a request for extension if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

7.4.2. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable; and

7.4.3. Updated timetable for implementing the selected actions in Part 7.1.

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 CAP, 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 submitted a request for extension to the ERO if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. 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. 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.

8.3.1. 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 Assessment: (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.

R11. Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental 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]*

11.1. 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.

11.2. Be developed within one year of completion of the supplemental GMD Vulnerability Assessment.

11.3. Include a timetable, subject to ERO approval for any extension sought under Part 11.4, for implementing the selected actions from Part 11.1. The timetable shall:

11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

11.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

11.4. Be submitted to the ERO with a request for extension if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. The submitted CAP shall document the following:

11.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures, if applicable; and

11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

11.5. 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.

11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental 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 R11. 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 submitted a request for extension to the ERO if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. 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 R11. 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 R11.

GMD Measurement Data Processes

R12. 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]*

M12. 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 R12.

R13. 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]*

M13. 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 R13.

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 and R11, 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 R12 and R13, 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 develop a Corrective Action Plan as required by Requirement R7.
R8.	The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R8, Parts 8.1 through 8.3; 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 the elements listed in Requirement R8, Parts 8.1 through 8.3; 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 8.3; 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 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.	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12.	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.
R13.	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 those Canadian jurisdictions where the Variance has been approved for use by the applicable governmental authority or has otherwise become effective in the jurisdiction.

This variance replaces all references to "Attachment 1" in the standard with "Attachment 1 or Attachment 1-CAN."

In addition, this Variance replaces Requirement R7, Part 7.3 through Part 7.5 and Requirement R11, Part 11.3 through Part 11.5 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part D.A.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.

D.A.7.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.7.3. The revised CAP shall document the following:

D.A.7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

D.A.7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable; and

D.A.7.4.3 Updated timetable for implementing the selected actions in Part 7.1.

D.A.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, (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, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision.

D.A.7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.7. 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, (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, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision. 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.

D.A.11.3. Include a timetable, subject to revision by the responsible entity in Part D.A.11.4, for implementing the selected actions from Part 11.1. The timetable shall:

D.A.11.3.1. 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.11.3.2. 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.

D.A.11.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.11.3. The revised CAP shall document the following:

D.A.11.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

D.A.11.4.2 Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures if applicable; and

D.A.11.4.3 Updated timetable for implementing the selected actions in Part 11.1.

D.A.11.5. 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, (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, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision.

D.A.11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental 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 R11. 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, (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 R11, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision. 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 R11.

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.
2	November 25, 2018	FERC Order issued approving TPL-007-2. Docket No. RM18-8-000	
3	February 7, 2019	Adopted by the NERC Board of Trustees	Canadian Variance
4	TBD	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order. 851

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.

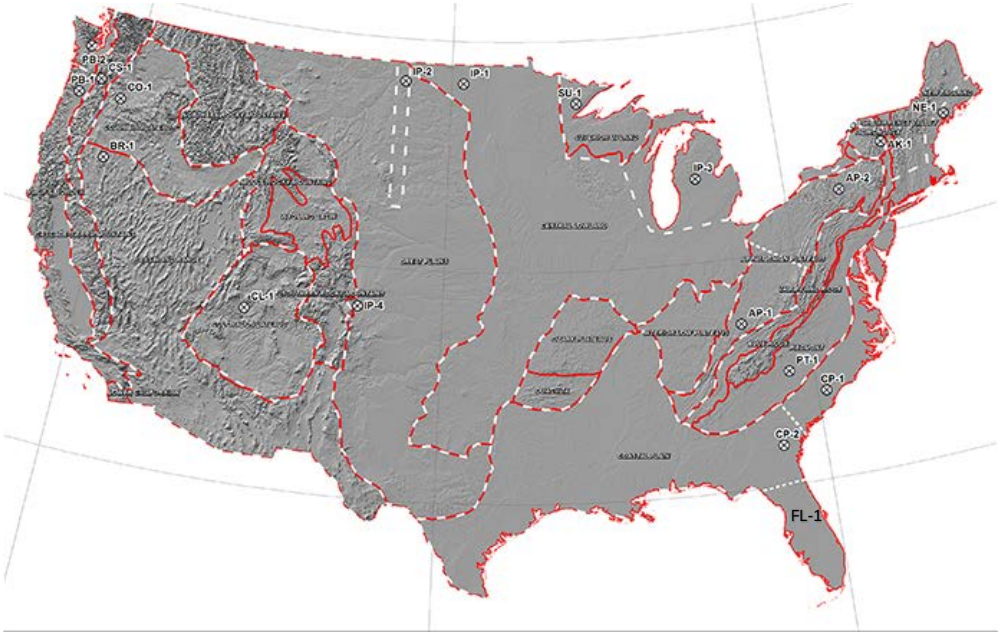


Figure 1: Physiographic Regions of the Continental United States[6]



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

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.

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.

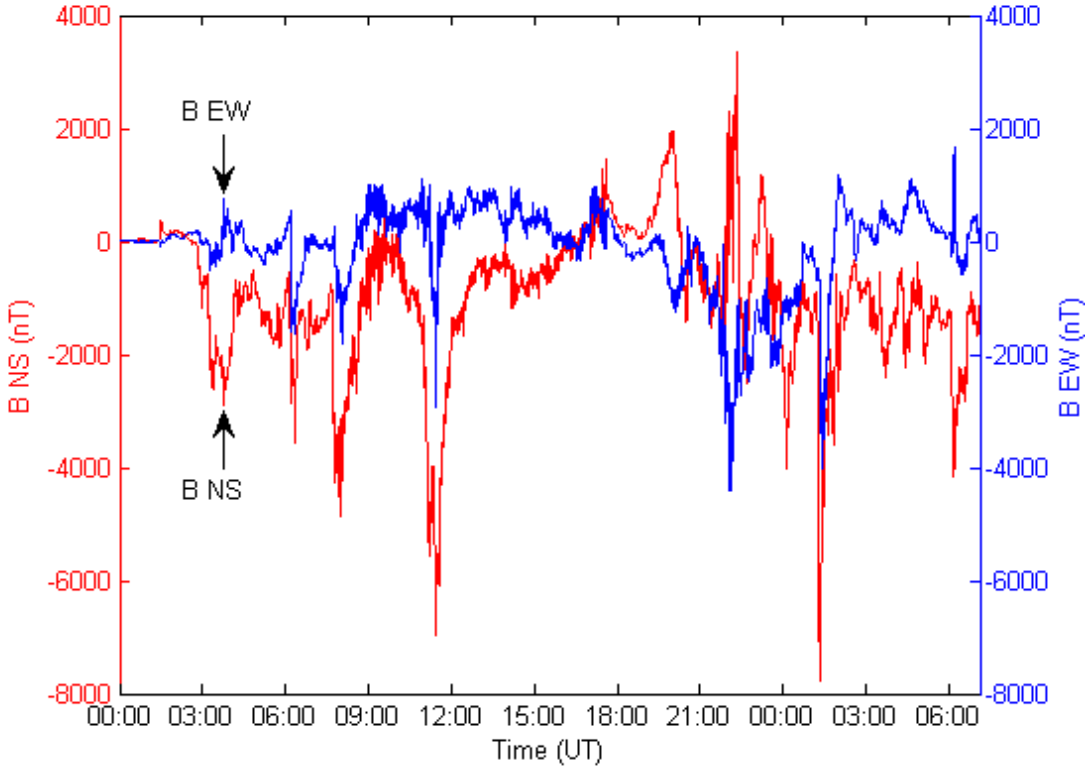


Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

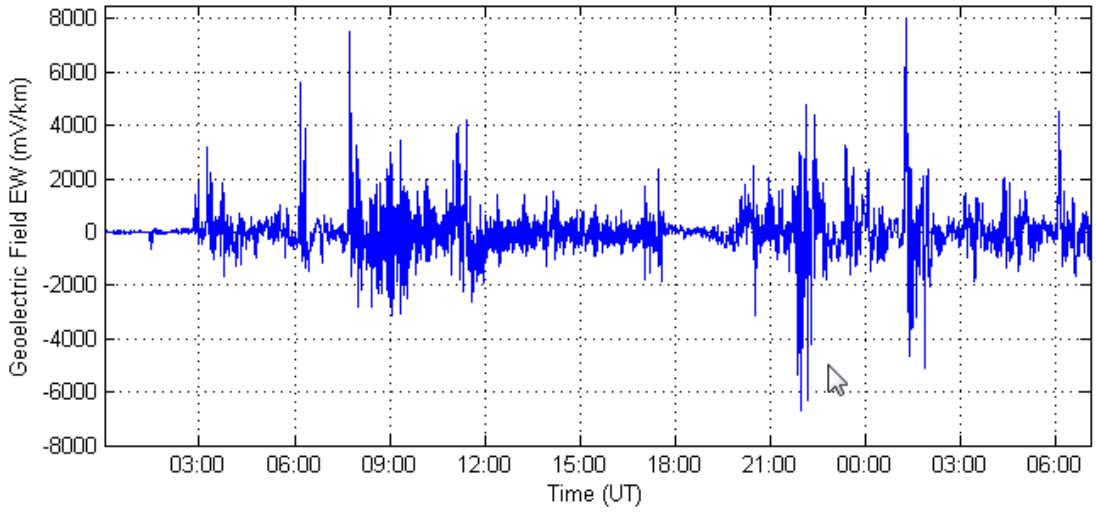


Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

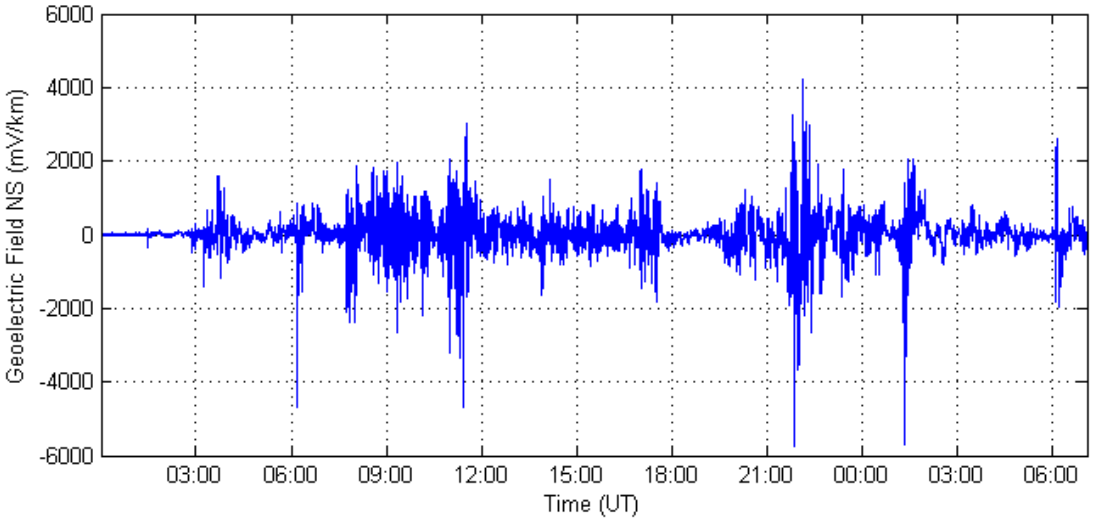


Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

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.

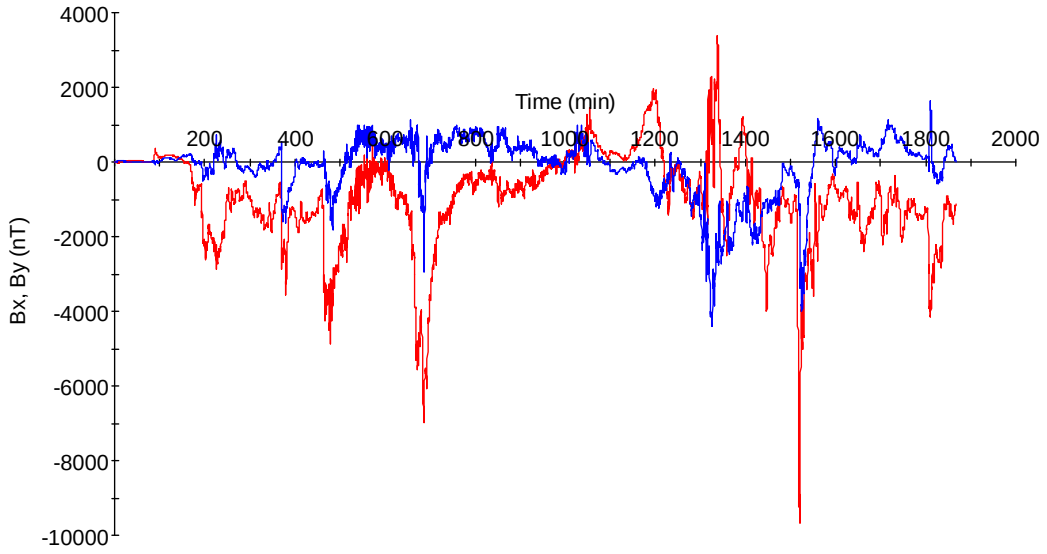


Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

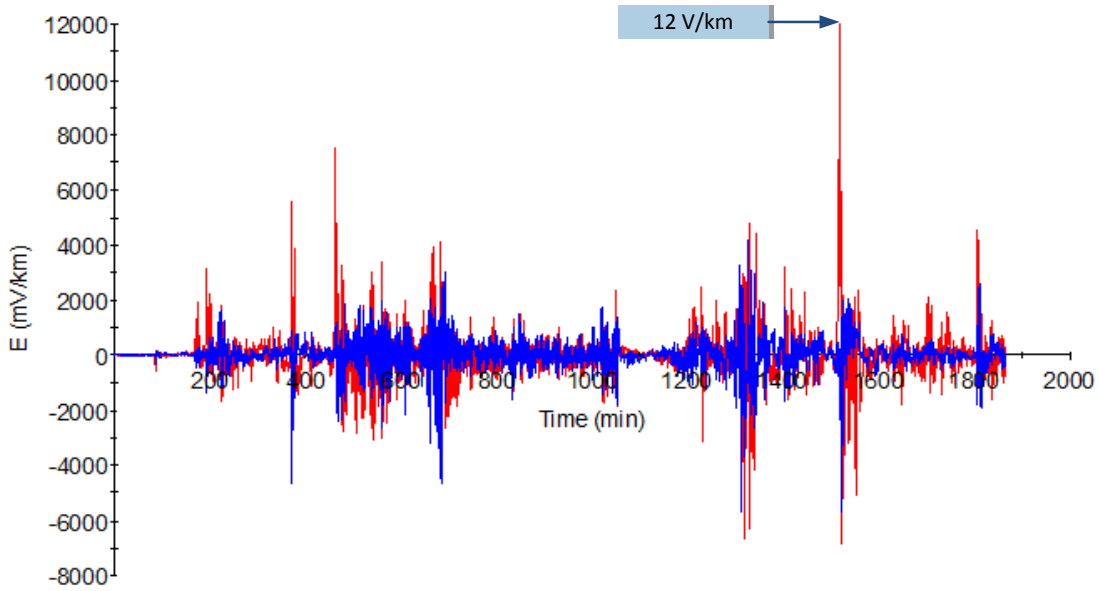


Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

Attachment 1-CAN provides an alternative that a 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).

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Consideration of Issues and Directives

Project 2019-01 Modifications to TPL-007-3

Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Modify the provision in Reliability Standard TPL-007-2, Requirement R7.4 that allows applicable entities to exceed deadlines for completing corrective action plan tasks when "situations beyond the control of the responsible entity [arise]", by requiring that NERC and the Regional Entities, as appropriate, consider requests for extension of time on a case-by-case basis. Under this option, responsible entities seeking an extension would submit the information required by Requirement R7.4 to NERC and the Regional Entities for their consideration of the request.	FERC Order No. 851, P 5 and P 50	The SDT proposed the modified language in Requirement R7.3 and R7.4 to require time extensions for completing CAPs be submitted to the ERO for approval. The proposed modified language reads as follows: 7.3. Include a timetable, subject ERO approval for any extension sought under 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 submitted to the ERO with a request for extension if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following; 7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part

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Project 2019-01 Modifications to TPL-007-3		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		7.1 and how those circumstances are beyond the control of each responsible entity; 7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable; and 7.4.3 Updated timetable for implementing the selected actions in Part 7.1.
Submit modifications to Reliability Standard TPL-007-2 to require corrective action plans for assessed supplemental GMD event vulnerabilities.	FERC Order No. 851, P 4 and P 39	The SDT drafted TPL-007-4 Requirement R11 to address require CAPs for supplemental GMD vulnerabilities and to require extensions to these plans to be approved by NERC and the Regional Entities, as appropriate, in situations beyond the control of the responsible entity. This language is the same as the modified Requirement R7 which addresses CAPs for the benchmark GMD vulnerability assessment. Requirement R8 was also modified to remove the original R8.3 which stated "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted"

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July 2019 - DRAFT Implementation Guidance
Pending Submittal for ERO Enterprise Endorsement

Transmission System Planned Performance for Geomagnetic Disturbance Events

Implementation Guidance for Reliability Standard TPL-007-4

July 2019

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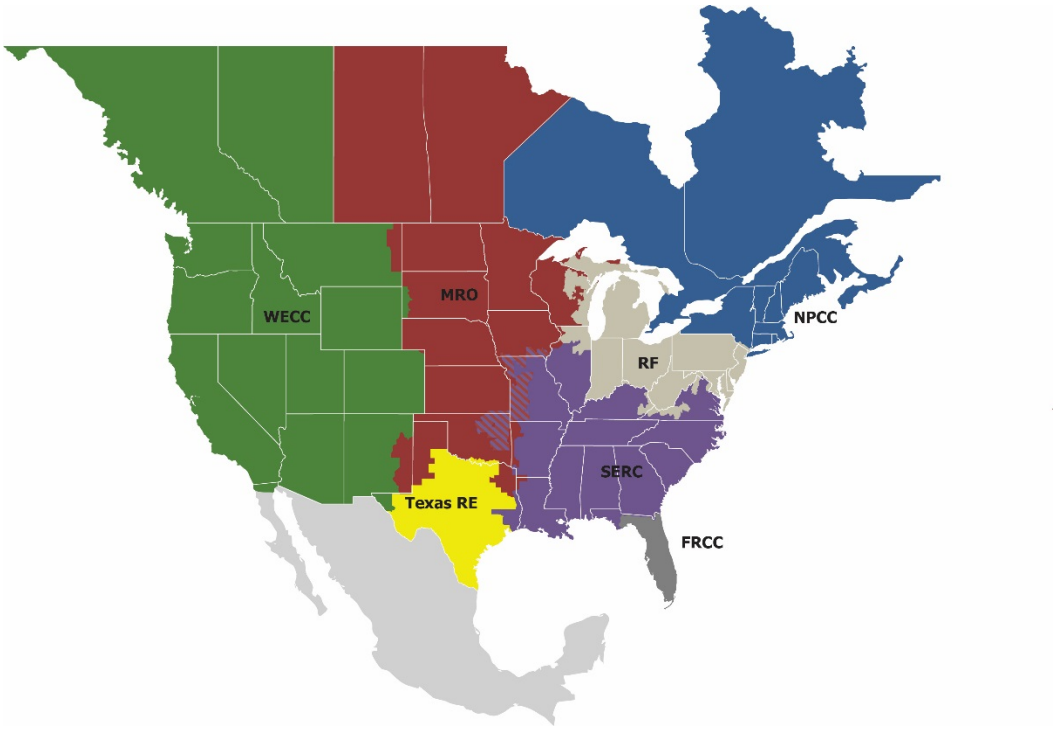
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Preface

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

Introduction

Background

The Standards Project 2019-01 Modifications to TPL-007-3 standard drafting team prepared this Implementation Guidance to provide example approaches for compliance with the modifications to TPL-007 - Transmission System Planned Performance for Geomagnetic Disturbance Events. Implementation Guidance does not prescribe the only approach, but highlights one or more approaches that would be effective in achieving compliance with the standard. Because Implementation Guidance only provides examples, entities may choose alternative approaches based on engineering judgement, individual equipment and system conditions.

The first version of the standard, TPL-007-1 which was approved in FERC's Order No. 779 [1], requires entities to assess the impact to their systems from a defined event referred to as the "Benchmark GMD Event." The second version of the standard, TPL-007-2, adds new Requirements R8, R9, and R10 to require responsible entities to assess the potential implications of a "Supplemental GMD Event" on their equipment and systems in accordance with FERC's directives in Order No. 830 [2]. Some GMD events have shown localized enhancements of the geomagnetic field. The supplemental GMD event was developed to represent conditions associated with such localized enhancement during a severe GMD event for use in a GMD Vulnerability Assessment. The third version of the standard, TPL-007-3, adds a Canadian variance for Canadian Registered Entities to leverage operating experience, observed GMD effects, and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflect their specific geographical and geological characteristics. No continent-wide requirements were changed between the second and the third versions of the standard. The fourth version, TPL-007-4, addresses the directives issued by FERC in Order No. 851 [3] to modify Reliability Standard TPL-007-3. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in TPL-007-3 Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis (P 54).

Chapter 1 – Requirement 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).

Chapter 2 – Requirement R2

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These system adjustments could for example include recalling or postponing maintenance outages.

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 enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations, such as this, in the GIC system model, if applicable.

Chapter 3 – Requirement 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 Planning GMD Event found in TPL-007-4. Steady state voltage limits are an example of System steady state performance criteria.

Chapter 4 – Requirement R4

Distribution of benchmark 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 considered by transmission planners.

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.

Chapter 5 – Requirement R5

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.

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 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.

Chapter 6 – Requirement R6

ERO Enterprise-Endorsed Implementation Guidance for conducting the thermal impact assessment of a power transformer is presented in the *Transformer Thermal Impact Assessment White Paper*, October 2016 [4].

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. 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 above referenced white paper and *the Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [5], for additional information.

Approaches for conducting the thermal impact assessment of transformers for the benchmark event are presented in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [6].

Thermal impact assessments for the benchmark event 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 (CAP; R7) as necessary.

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.

Chapter 7 – Requirement R7

The proposed requirement addresses directives in FERC Order No. 830 for establishing CAP deadlines associated with GMD Vulnerability Assessments. In FERC 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 NERC to establish implementation deadlines after the completion of the CAP as follows (P 102):

- Two years for non-hardware mitigation; and
- Four years for hardware mitigation.

Part 7.4 requires entities to submit to the ERO with a request for extension when implementation of planned mitigation is not achievable within the deadlines established in Part 7.3. Examples of situations beyond the control of the responsible entity 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.

Chapter 8 – Supplemental GMD Vulnerability Assessment

The exact spatial extent, local time of occurrence, latitude boundary, number of occurrences during a GMD event, and geoelectric field characteristics (amplitude and orientation) inside/outside the local enhancement cannot yet be scientifically determined.

TPL-007-4 provides flexibility for Transmission Planners to determine how to apply the supplemental GMD event to the planning area. This guide provides acceptable approaches and boundaries to apply the supplemental event.

1. Spatial extent:
    a. The local geoelectric field enhancement should not be smaller than 100 km (West-East) by 100 km (North-South).
    b. The transmission planner may perform a sensitivity analysis varying the spatial extent. Note that the 100 km North-South spatial extent is better understood than the West-East length, which could be 500 km or more.
    c. The peak geoelectric field for the supplemental GMD event (12 V/km scaled to the planning area) can be applied over the entire planning area. Note that this implies studying a GMD event rarer than 1-in-100 years.
2. Geoelectric field inside the local enhancement:
    a. Amplitude: 12 V/km (scaled to the planning area).
    b. Orientation: at a minimum, a West-East[1] orientation should be considered when applying the supplemental event.
    c. The transmission planner may perform a sensitivity analysis varying the orientation of the geoelectric field.
3. Geoelectric field outside[2] the local enhancement:
    a. Amplitude: should not be smaller than 1.2 V/km (scaled to the planning area); i.e., an order of magnitude smaller than the field inside the local enhancement.
    b. Orientation: at a minimum, a West-East[3] orientation should be considered when applying the supplemental event.
    c. The transmission planner may perform a sensitivity analysis varying the orientation of the geoelectric field.
4. Position of the local enhancement:
    a. The transmission planner may use engineering judgement to position the local enhancement on critical areas of their system. For example, the benchmark vulnerability assessment may identify areas with depressed voltages, lack of dynamic reactive reserves, large GIC flows through transformers, etc. The transmission planner may also consider the impact to critical infrastructure or other externalities.
    b. The transmission planner may systematically move the position of the local enhancement throughout the entire planning area.

[1] West-East geomagnetic reference.

[2] The characteristics of the geoelectric field outside the local enhancement, for example amplitude, orientation, spatial extent, are still being reviewed by the scientific community.

[3] West-East geomagnetic reference.

c. Despite the fact that local enhancements appear to be limited to auroral regions, geomagnetic latitude should not be used as a criterion to position the local enhancement.

The schematic in Figure 1 illustrates the boundaries to apply the supplemental GMD event. The local enhancement should not be smaller than 100 km by 100 km, the geoelectric field inside the local enhancement is 12 V/km (scaled to the planning area) with West-East orientation, and the geoelectric field outside the local enhancement could be as low as 1.2 V/km (scaled to the planning area) with a West-East orientation.

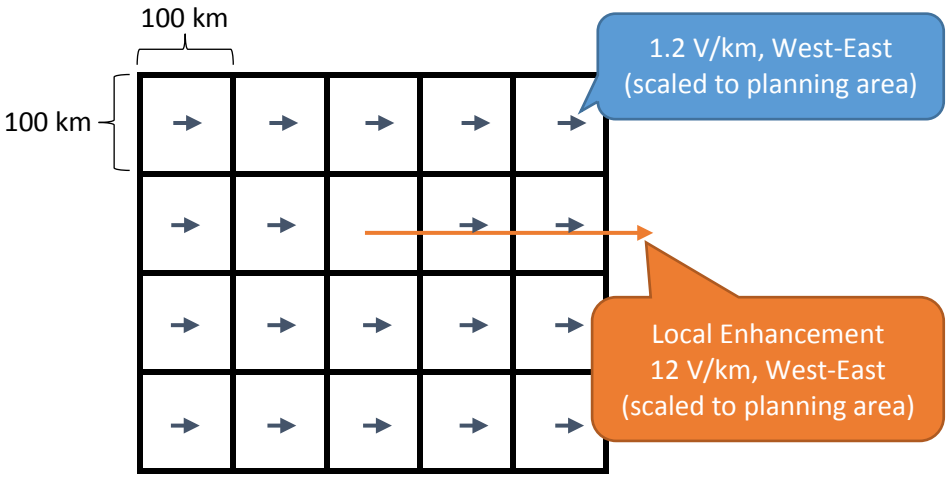


Figure 1. Schematic showing the boundaries to apply the supplemental event.

Chapter 9 – Requirement R8

Distribution of supplemental 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 considered by transmission planners.

The provision of information in Requirement R8, Part 8.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 10 – Requirement R9

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.

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 no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R9, Part 9.1.

The provision of information in Requirement R9 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 11 – Requirement R10

ERO Enterprise-Endorsed Implementation Guidance for conducting the thermal impact assessment of a power transformer is presented in the *Transformer Thermal Impact Assessment White Paper*, October 2016 [4].

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. 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 above referenced white paper and the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [5] for additional information.

Approaches for conducting the thermal impact assessment of transformers for the supplemental event are presented in the *Transformer Thermal Impact Assessment White Paper*, October 2017 [6].

Thermal impact assessments for the supplemental event are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R8) and the Corrective Action Plan (R11) as necessary.

The provision of information in Requirement R10, Part 10.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Chapter 12 – Requirement R11

The requirement addresses directives in FERC Order No. 851 to develop and submit modifications to Reliability Standard TPL-007-2 (and TPL-007-3) to require corrective action plans for assessed supplemental GMD event vulnerabilities. This requirement is analogous to Requirement R7, such that CAPs are developed within one year from the completion of supplemental GMD Vulnerability Assessments and establishment of implementation deadlines after the completion of the CAP as follows:

- Two years for non-hardware mitigation; and
- Four years for hardware mitigation.

Part 11.4 requires entities to submit to the ERO with a request for extension when implementation of planned mitigation is not achievable within the deadlines established in Part 11.3. Examples of situations beyond the control of the responsible entity 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.

Chapter 13 – Requirement R12

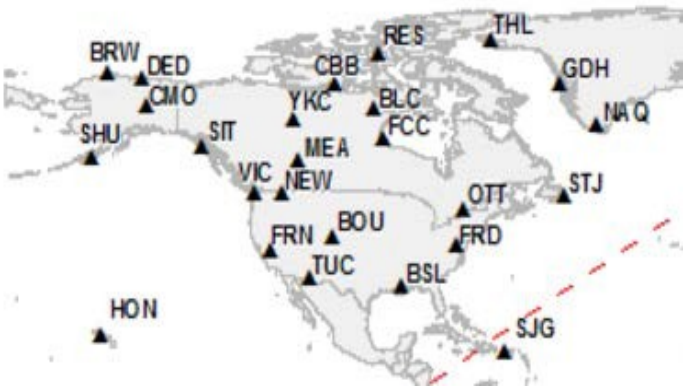
Responsible entities consider the following in developing a process for obtaining GIC monitor data:

- 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 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 (for example 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 (for example -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 one (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 (for example three-phase or single-phase).

Chapter 14 – Requirement R13

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 (USGS) and Natural Resources Canada (NRCan), see figure below for locations [7];



- Research institutions and academic universities; and
- Entities with installed magnetometers.

Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the *INTERMAGNET Technical Reference Manual*, Version 4.6, 2012 [8].

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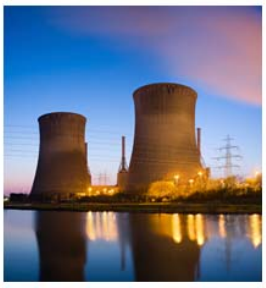
July 2019 - DRAFT Technical Rationale
Pending Submittal for ERO Enterprise Endorsement

Transmission System Planned Performance for Geomagnetic Disturbance Events

Technical Rationale and Justification for Reliability Standard TPL-007-4

July 2019

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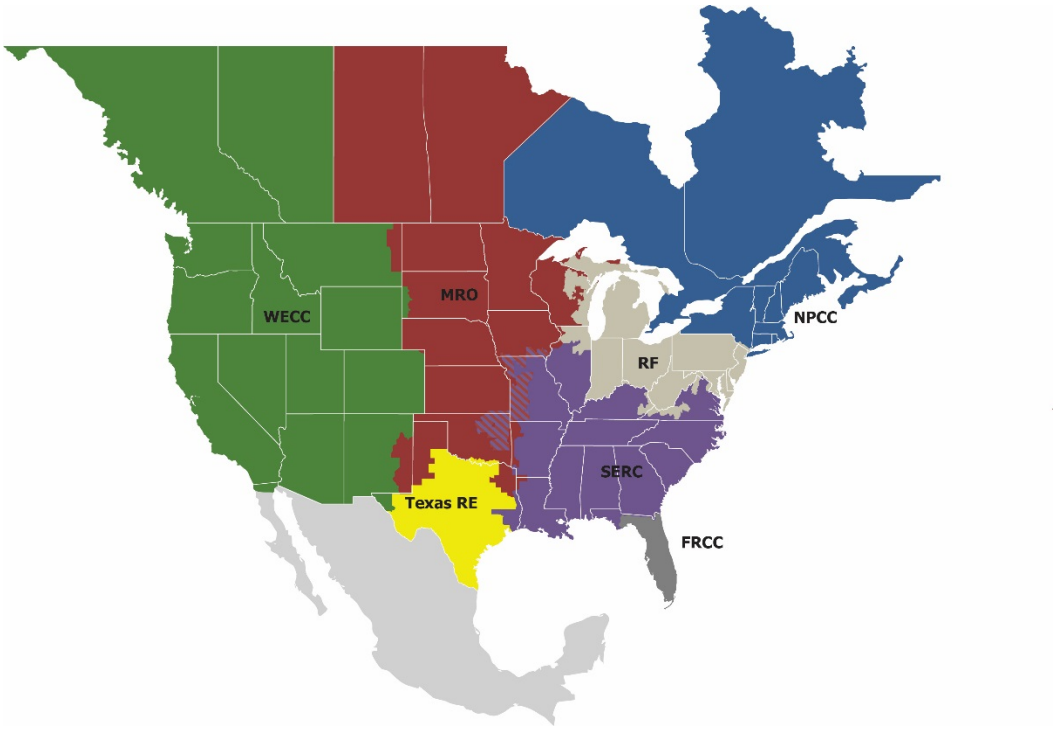
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Preface

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

Introduction

Background

This document explains the technical rationale and justification for the proposed Reliability Standard TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events. It provides stakeholders and the ERO Enterprise with an understanding of the technical requirements in the Reliability Standard. It also contains information on the standard drafting team's intent in drafting the requirements. This document, the Technical Rationale and Justification for TPL-007-4, is not a Reliability Standard and should not be considered mandatory and enforceable.

The first version of the standard, TPL-007-1, approved by FERC in Order No. 779 [1], requires entities to assess the impact to their systems from a defined event referred to as the "Benchmark GMD Event." The second version of the standard, TPL-007-2, adds new Requirements R8, R9, and R10 to require responsible entities to assess the potential implications of a "Supplemental GMD Event" on their equipment and systems in accordance with FERC's directives in Order No. 830 [2]. Some GMD events have shown localized enhancements of the geomagnetic field. The supplemental GMD event was developed to represent conditions associated with such localized enhancement during a severe GMD event for use in a GMD Vulnerability Assessment. The third version of the standard, TPL-007-3, adds a Canadian variance for Canadian Registered Entities to leverage operating experience, observed GMD effects, and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflect Canadian-specific geographical and geological characteristics. No continent-wide requirements were changed between the second and the third versions of the standard. The fourth version of the standard, TPL-007-4, addresses the directives issued by FERC in Order No. 851 [3] to modify Reliability Standard TPL-007-3. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in TPL-007-3 with a process through which extensions of time are considered on a case-by-case basis (P 54).

The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process. Figure 1 provides an overall view of the GMD Vulnerability Assessment process:

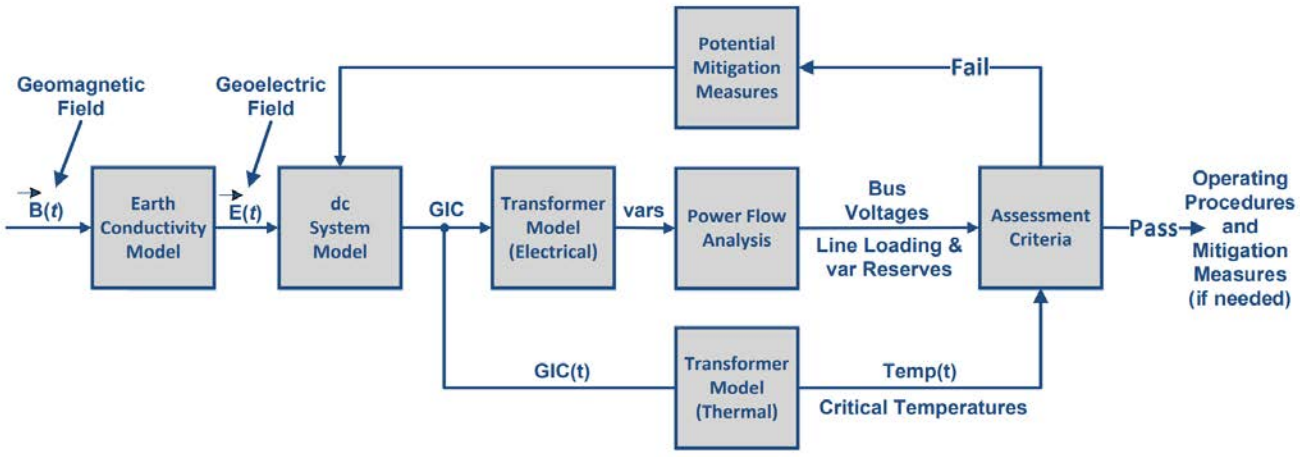


Figure 1. GMD Vulnerability Assessment Process.

Chapter 1 – General Considerations

Rationale for Applicability

Reliability Standard TPL-007-4 is applicable to Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these types of transformers are not included in the applicability for this standard. Terminal voltage describes line-to-line voltage.

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 [4], 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 [5], includes the event description and analysis.

Chapter 2 – 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 *Application Guide – Computing Geomagnetically-Induced Current in the Bulk-Power System*, December 2013 [6].

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*, December 2013 [6].

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.

Chapter 3 – Requirement R4

The *Geomagnetic Disturbance Planning Guide*, December 2013 [7], provides technical information on GMD-specific considerations for planning studies.

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: Steady State Planning GMD Event found in TPL-007-4. At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Chapter 4 – 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 for the benchmark thermal impact assessment should be provided in accordance with Requirement R5 each time the benchmark 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 peak GIC value of 75 Amps per phase, in the benchmark GMD Vulnerability Assessment, 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.

This GIC information is necessary for determining the benchmark 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 benchmark GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

GIC(t) provided in Part 5.2 can be used to convert the steady state GIC flows to time-series GIC data for the benchmark 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*, October 2017 [8].

Chapter 5 – 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. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [9].

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.

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.

Chapter 6 – Requirement R7

The requirement addresses directives in FERC Order No. 851 to replace the time-extension provision in Requirement R7.4 of TPL-007-2 (and TPL-007-3) with a process through which extensions of time are considered on a case-by-case basis.

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *Geomagnetic Disturbance Planning Guide*, December 2013 [7]. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [10].

Chapter 7 – Supplemental GMD Vulnerability Assessment

The requirements address directives in FERC Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (PP 44, 47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.

Chapter 8 – Requirement R8

The *Geomagnetic Disturbance Planning Guide*, December 2013 [7], 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.

Chapter 9 – 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 for the supplemental thermal impact assessment should be provided in accordance with Requirement R9 each time the supplemental 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 peak GIC value of 85 Amps per phase, in the supplemental GMD Vulnerability Assessment, 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.

This GIC information is necessary for determining the supplemental 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 supplemental GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

GIC(t) provided in Part 9.2 can be used to convert the steady state GIC flows to time-series GIC data for the supplemental 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*, October 2017 [8].

Chapter 10 – 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. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment White Paper*, October 2017 [9].

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 R9.

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.

Chapter 11 – Requirement R11

The requirement addresses directives in FERC Order No. 851 to develop and submit modifications to Reliability Standard TPL-007-2 (and TPL-007-3) to require corrective action plans for the assessed supplemental GMD event vulnerabilities.

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the Geomagnetic Disturbance Planning Guide, December 2013 [7]. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System*, February 2012 [10].

Chapter 12 – Requirement R12

GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R12 and R13, respectively. This requirement addresses directives in FERC Order No. 830 for requiring responsible entities to collect GIC monitoring data as necessary to enable model validation and situational awareness (PP 88, 90-92).

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*, February 2012 [10]. GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer and measure dc current flowing through the neutral. Data from GIC monitors is useful for model validation and situational awareness.

The objective of Requirement R12 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*, February 2012 [10].

Chapter 13 – Requirement R13

GMD measurement data refers to GIC monitor data and geomagnetic field data in Requirements R12 and R13, respectively. This requirement addresses directives in FERC Order No. 830 for requiring responsible entities to collect magnetometer data as necessary to enable model validation and situational awareness (PP 88, 90-92).

The objective of Requirement R13 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 2019-01 Modifications to TPL-007-3

Applicable Standard

- TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Requested Retirement

- TPL-007-3 – 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 November 15, 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 851 approving Reliability Standard TPL-007-2 and its associated implementation plan. In the order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 12 months from the effective date of Reliability Standard TPL-007-2 to submit a revised standard (July 1, 2020).

On February 7, 2019, the NERC Board of Trustees adopted Reliability Standard TPL-007-3, which added a Variance option for applicable entities in Canadian jurisdictions. No continent-wide requirements were changed. Under the terms of its implementation plan, Reliability Standard TPL-007-3 became effective in the United States on July 1, 2019. All phased-in compliance dates from the TPL-007-2 implementation plan were carried forward unchanged in the TPL-007-3 implementation plan.

General Considerations

This implementation plan is intended to integrate the new and revised requirements in TPL-007-4 in the existing timeframe under the TPL-007-3 implementation plan.

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.

Reliability Standard TPL-007-4

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 six (6) 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 six (6) 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

Compliance Date for TPL-007-4 Requirements R1, R2, R5, and R9

Entities shall be required to comply with Requirements R1, R2, R5, and R9 upon the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R12 and R13

Entities shall not be required to comply with Requirements R12 and R13 until the later of: (i) July 1, 2021; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R6 and R10

Entities shall not be required to comply with Requirements R6 and R10 until the later of: (i) January 1, 2022; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R3, R4, and R8

Entities shall not be required to comply with Requirements R3, R4, and R8 until the later of: (i) January 1, 2023; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirement R7
Entities shall not be required to comply with Requirement R7 until the later of: (i) January 1, 2024; or (ii) the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirement R11
Entities shall not be required to comply with Requirement R11 until the later of: (i) January 1, 2024; or (ii) six (6) months after the effective date of Reliability Standard TPL-007-4.

Retirement Date

Standard TPL-007-3
Reliability Standard TPL-007-3 shall be retired immediately prior to the effective date of TPL-007-4 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 Justification

Project 2019-01 Modifications to TPL-007-3

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 TPL-007-4. 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-007-4, Requirement R1
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R1
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R2
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R2
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R3
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R3
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R4
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R4
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R5
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R5
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R6
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R6
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R7
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R7
The VSL did not substantively change from the previously FERC-approved TPL-007-3 Reliability Standard. In the Severe VSL, the word "have" was replaced with "develop" to more closely reflect the language of the Requirement.

VRF Justification for TPL-007-4, Requirement R8
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R8
The justification is provided on the following pages.

VRF Justification for TPL-007-4, Requirement R9
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R9
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R10
The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R10
The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R11
The justification is provided on the following pages.

VSL Justification for TPL-007-4, Requirement R11
The justification is provided on the following pages.

VRF Justification for TPL-007-4, Requirement R12

Requirement R12 was previously Requirement R11 in TPL-007-3. The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R12

Requirement R12 was previously Requirement R11 in TPL-007-3. The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VRF Justification for TPL-007-4, Requirement R13

Requirement R13 was previously Requirement R12 in TPL-007-3. The VRF did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSL Justification for TPL-007-4, Requirement R13

Requirement R13 was previously Requirement R12 in TPL-007-3. The VSL did not change from the previously FERC-approved TPL-007-3 Reliability Standard.

VSLs for TPL-007-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.3; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.

VSL Justifications for TPL-007-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs retain the VSLs from FERC-approved TPL-007-3 with the exception of removing one part of the lower VSL to reflect the removal of subpart 8.3 in TPL-007-3. As a result, the proposed VSLs do not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed 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	Each VSL is based on a single violation and not cumulative violations.

VSLs for TPL-007-4, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5; OR The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.

VSL Justifications for TPL-007-4, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance. Further, the VSLs are consistent with those assigned for Requirement R7, pertaining to Corrective Action Plans for benchmark GMD Vulnerability Assessments.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for TPL-007-4, Requirement R11	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-007-4, Requirement R11	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of High is being proposed for this requirement.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The proposed VRF is consistent among other FERC approved VRFs within the standard, specifically Requirement R7 pertaining to Corrective Action Plans for benchmark GMD Vulnerability Assessments.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High is consistent with Reliability Standard TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to include a Corrective Action Plan that addresses identified performance issues in the annual Planning Assessment.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The VRF of High is consistent with the NERC VRF Definition. Failure to develop a Corrective Action Plan that addresses issues identified in a supplemental GMD Vulnerability Assessment could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.

VRF Justifications for TPL-007-4, Requirement R11	
Proposed VRF	**Lower**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

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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:	BES Cyber System Information Access Management		
Date Submitted:	March 1, 2019		
SAR Requester			
Name:	Alice Ireland		
Organization:	Tri-State Generation and Transmission Association		
Telephone:	(303) 254-3120	Email:	aireland@tristategt.org
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?):			
While there is no direct benefit to the reliability of the BES, this initiative enhances BES reliability by creating increased choice, greater flexibility, higher availability, and reduced-cost options for entities to manage their BES Cyber System Information, by providing a secure path towards utilitzation of modern third-party data storage and analysis systems. In addition, the proposed project would clarify the protections expected when utilizing third-party solutions (aka cloud).			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Clarifying the CIP requirements related to BES Cyber System Information access, to allow for alternative methods, such as encryption, to be utilized in the protection of BCSI.			
Project Scope (Define the parameters of the proposed project):			
CIP-004 and CIP-011			

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
CIP-004-6 Requirement R4 Part 4.1.3 needs to be modified so authorization and access to BCSI is clarified to focus on the BCSI and the controls deployed to limit access. In addition, the Standard should allow multiple methods for controlling access to BES Cyber System Information, rather than just electronic and physical access to the BES Cyber System Information storage location. For example, the focus must be on BCSI and the ability to obtain and make use of it. This is particularly necessary when it comes to the utilization of a third party's system (aka cloud). As currently drafted, the requirement is focused on access to the "storage location", and therefore does not permit methods such as encryption and key management to be utilized in lieu of physical/electronic access controls. This wording also does not explicitly permit any flexibility in the audit approach. In addition to modifying CIP-004-6 Requirement R4 Part 4.1.3, Part 4.4, Part 5.3 and CIP-011-2 Requirement R1 should also be evaluated for any subsequent impacts to the requirements, measures and/or the guidelines and technical basis.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Potential cost savings due to economies of scale and third party support.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
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):
Please see Section 4. Applicability of CIP-004-6 and CIP-011-2.
Do you know of any iconsensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus bulding activity.
An informal team, under the direction of the NERC Compliance Input Working Group, was assembled to review the use of encryption on BES Cyber System Information, and the impact on compliance, with a particular focus on such BES Cyber System Information being stored or utilized by a third party's system (aka cloud). This team met every two weeks during Dec. 2018 – Feb. 2019. The development of this SAR was supported by all team members. The team consisted of the following individuals:

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

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

Requested information

Name	Company
Alice Ireland (lead)	Tri-State Generation and Transmission
David Vitkus	Tucson Electric Power
Eric Hull	SMUD
Marina Rohnow	Sempra Utilities/ San Diego Gas & Electric
Paul Haase	Seattle City Light
Richie Field	Hoosier Energy REC, Inc.
Rob Ellis	Tri-State Generation and Transmission
Steve Wesling	Tri-State Generation and Transmission
Toley Clague	Portland General Electric
Ziad Dassouki	ATCO Electric
Joseph Baxter	NERC
Lonnie Ratliff	NERC
Brian Kinstad	MRO
Holly Eddy	WECC
Kenath Carver	Texas Reliability Entity, Inc.
Michael Taube	MRO
Mike Stuetzle	NPCC
Morgan King	WECC
Shon Austin	Reliability First
Tremayne Brown	SERC

Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?

Project 2016-02 Modifications to CIP Standards

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.

When evaluating ways to modify the requirement, other standards and requirements were identified, which provide examples on possible paths forward. Of particular relevance are the following standards/requirements:

- CIP-006-6 Requirement R1 Part 1.10;
- CIP-010-2 Requirement R4, Attachment 1, Section 1.5;
- CIP-012-1 Requirement R1 (pending FERC approval).

Requested information

As a means to assist the SDT, several possible options for revision to CIP-004-6 Requirement R4 Part 4.1.3 have been drafted and provided below:

EXAMPLE #1:
[Delete 4.1.3 and create a new subrequirement in either CIP-004 or CIP-011, that would read something like this:]
R4.X Process to prevent unauthorized access to BES Cyber System Information. The process shall include:
4.X.1. Identification of physical and electronic repositories utilized to store BES Cyber System Information. If electronic, indicate whether the repository is hosted by the Responsible Entity or a third-party and also whether it is in a virtual or non-virtual environment.;
4.X.2. Identification of security protection(s) used to prevent unauthorized access to BES Cyber System Information within each repository. Examples may include but are not limited to the following:

- Encryption and key management,
- Physical access management,
- Electronic access management,
- Data loss prevention techniques and rights management services.

4.X.3. The process to authorize access to BES Cyber System Information, based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances;

EXAMPLE #2:
R4.1 Process to authorize based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances:
4.1.1. Electronic access;
4.1.2. Unescorted physical access into a Physical Security Perimeter;
4.1.3. Physical access to physical BES Cyber System Information storage locations;
4.1.4. Physical access to unencrypted electronic BES Cyber System Information storage locations;
4.1.5. Electronic access to unencrypted electronic BES Cyber System Information storage locations; and
4.1.6. Electronic access to BES Cyber System Information encryption keys for encrypted BES Cyber System Information.

EXAMPLE #3:
R4.1 Process to authorize based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances:
4.1.1. Electronic access;
4.1.2. Unescorted physical access into a Physical Security Perimeter;
4.1.3. Physical access to physical BES Cyber System Information storage locations;
4.1.4. Access to electronic BES Cyber System Information.

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

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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	

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

Version History

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

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Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	Revisions to Cyber Security – Supply Chain Controls Standard		
Date Submitted:	June 26, 2019		
SAR Requester			
Name:	Soo Jin, Manager of Standards Development		
Organization:	NERC		
Telephone:	404.831.4765	Email:	Soo.jin.kim@nerc.net
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
On October 18, 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 850 directing NERC to develop modifications to the Supply Chain Standards. In addition, NERC published a Cyber Security Supply Chain Risks report and recommendations for additional modifications to the Supply Chain Standards.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project will address the directives issued by FERC in Order No. 850 to modify the Supply Chain Standards. FERC directed NERC to submit modifications to address EACMSs, specifically those systems that provide electronic access control to high and medium impact BES Cyber Systems. FERC directed NERC to submit the modified Reliability Standard including the directed revisions for approval within 24 months from the effective date of Order No. 850. In addition, NERC also recommends revising the Supply Chain Standards to address Physical Access Control Systems (PACS) that provide physical access control (excluding alarming and logging) to high and medium impact BES Cyber Systems. The modifications to address PACS do not have a regulatory deadline, but will be addressed by this project.			

Requested information
Project Scope (Define the parameters of the proposed project):
This project will address the directives issued by FERC in Order No. 850. This project will also address NERC staff recommendation from the Supply Chain Report to address Physical Access Control Systems (PACS) that provide physical access control (excluding alarming and logging) to high and medium impact BES Cyber Systems.
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):
Consider recommendations to revise the Supply Chain Reliability Standards to include: (i) EACMSs, specifically those systems that provide electronic access control (excluding monitoring and logging) to high and medium impact BES Cyber Systems; and (ii) PACSs that provide physical access control (excluding alarming and logging) to high and medium impact BES Cyber Systems.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impact is unknown at this time. However, a question will be asked during the SAR comment period to ensure all aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
Submitter asserts there are no unique characteristics associated with BES facilities that will be impacted by this proposed standard development project.
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):
Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Distribution Provider, Generator Owner, Generator Operator
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
No
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
Project 2016-02 Modifications to CIP Standard
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.
None at this time

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

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

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

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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
	None identified

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

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Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
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		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
361	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	12/11/2012	12/20/2012	Quorum: 83.24% Approval: 84.48%	Support 12/19/12		
362	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 79.00% Approval: 79.36%			
364	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.68% Approval: 74.27%			
365	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 85.87% Approval: 73.63%			
366	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.19% Approval: 76.53%			
367	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	1/2/2013	1/11/2013	Quorum: 78.16% Approval: 60.31%	Support 1/11/13		
368	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	Non-binding Poll	1/2/2013	1/11/2013	Quorum: 76.38% Approval: 55.68%			
369	Project 2010-11	Project 2010-11 Successive Ballot December 2012 in	Successive Ballot	1/2/2013	1/11/2013	Quorum: 85.47% Approval: 65.77%	No Consensus 1/11/13		
370	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Initial Ballot	1/4/2013	1/14/2013	Quorum: 83.94% Approval: 21.80%	Oppose 1/11/13		
371	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Non-binding Poll	1/4/2013	1/14/2013	Quorum: 82.23% Approval: 24.27%			
372	Project 2013-02	Project 2013-02 - Paragraph 81	Recirculation Ballot	1/8/2013	1/17/2013	Quorum: 84.60% Approval: 95.22%	Support 12/10/12		
373	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Recirculation Ballot	1/14/2013	1/23/2013	Quorum: 87.13% Approval: 99.09%	Support 12/19/12		
374	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Recirculation Ballot	1/18/2013	1/28/2013	Quorum: 85.90% Approval: 85.57%	Support 12/19/12		
375	Project 2010-11	Project 2010-11 Recirculation Ballot Jan 2013 in	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 88.55% Approval: 69.63%	No Consensus 1/11/13		
376	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 85.67% Approval: 77.61%	Oppose 12/5/12		
377	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Successive Ballot	2/11/2013	2/20/2013	Quorum: 77.62% Approval: 50.66%	Support 9/5/12		
378	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	2/11/2013	2/20/2013	Quorum: 75.38% Approval: 50.60%			
379	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	2/15/2013	2/28/2013	Quorum: 78.80% Approval: 89.01%	Support 1/11/13		
380	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Non-binding Poll	2/15/2013	2/28/2013	Quorum: 76.38% Approval: 84.24%			
381	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Initial Ballot	3/1/2013	3/11/2013	Quorum: 76.36% Approval: 54.65%			
382	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Successive Ballot	3/13/2013	3/22/2013	Quorum: 77.48% Approval: 84.27%	No Consensus 3/22/13		NPCC to abstain - international nature of the ERO and BPS is not used in Reliability Standards
383	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.58% Approval: 97.18%	Support 3/14/13		
384	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.52% Approval: 98.89%	Support 3/14/13		
385	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Recirculation Ballot	3/18/2013	3/27/2013	Quorum: 81.33% Approval: 89.44%	Support 1/11/13		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
386	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	3/27/2013	4/5/2013	Quorum: 78.39% Approval: 57.50%	No Consensus 4/4/13		The RSC did not reach a full consensus however the majority of respondents had indicated they will support the standard - see comment form for further details. Some believe the standard is not necessary and that existing whitepapers alleviate the need for it. In recognition of the NERC BOT's expectations that COM-003 will be approved by the industry and brought before them for approval, NPCC has voted affirmatively and will supply comments for the record outlining our concerns.
387	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	3/27/2013	4/5/2013	Quorum: 77.97% Approval: 54.28%			
388	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.60% Approval: 66.98%	No Consensus 4/23/13		The majority of NPCC's Balancing Authorities have indicated support for the standard, however NPCC as the Regional Entity has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. To be respectful of the positions of the NPCC BAs who will have to implement this new methodology and the support expressed, NPCC as the Regional Entity will cast an Abstention
389	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 42.75%	Oppose 4/23/13		There is a lack of technical justification for the 500 MW threshold within the standard-NPCC will submit suggested improvements
390	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 23.84%	Oppose 4/23/13		Losses of large blocks of load are typically caused by coincident transmission contingencies. Excessive and uninformed adjustments made to generation in order to bring the ACE to zero may well lead to further transmission issues. NPCC will submit suggested improvements
391	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
392	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
393	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
394	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Recirculation Ballot	4/18/2013	4/29/2013	Quorum: 80.70% Approval: 88.15%	No Consensus 3/22/13		
395	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Successive ballot	5/15/2013	5/24/2013	Quorum: 81.25% Approval: 69.23%	Support 5/23/13		The Regional Standard Committee has not expressed any concerns of significance that would warrant a ballot to reject, therefore the RSC recommends a yes vote, "Affirmative", to accept the standard
396	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Non-binding Poll	5/15/2013	5/24/2013	Quorum: 80.17% Approval: 61.11%			
397	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Successive Ballot	6/24/2013	7/3/2013	Quorum: 77.65% Approval: 52.71%			
398	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Non-binding Poll	6/24/2013	7/3/2013	Quorum: 77.12% Approval: 52.48%			
399	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Initial Ballot	7/3/2013	7/12/2013	Quorum: 85.53% Approval: 49.73%			
400	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Successive Ballot	7/10/2013	7/19/2013	Quorum: 76.32% Approval: 58.36%	No Consensus 7/19/13 [Due to the concerns expressed over the potential actions by the NERC BOT and FERC as well as the incremental improvement of the standard over the previous versions, NPCC as the Regional Entity will support the standard and submit comments.]		[illegible] organizations support the standard as written however some members expressed concern that in order to measure compliance with R1 and R2, the standard will require all Reliability Directives to be investigated to determine if RC approved and documented communication protocols have been violated. Also it was identified that TO, BA communication protocols would have to approved by the RC potentially causing some legal issues if protocols aren't approved and casts question on the enforcement of those protocols. NPCC will be submitting some helpful comments should the standard pass and some non-substantive revision be performed prior to the "final" (previously named recirculation) ballot.
401	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 76.20% Approval: 55.37%			
402	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Successive Ballot	7/10/2013	7/19/2013	Quorum: 85.05% Approval: 72.43%	Support 7/19/13		
403	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 82.51% Approval: 64.59%			
404	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Final Ballot	7/16/2013	7/25/2013	Quorum: 92.31% Approval: 74.54%	No Consensus 7/22/13		The RSC has not reached a full consensus however the majority are in support. Issues outstanding for those not in support are concern over "hitting limits" more frequently and potential issues with BA's potentially "dragging" on the interconnection. NPCC will be voting affirmative on the standard.

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
405	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Initial Ballot	7/26/2013	8/5/2013	Quorum: 80.05% Approval: 93.00%	Support 8/5/13		
408	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025-1	Final Ballot	8/2/2013	8/12/2013	Quorum: 89.13% Approval: 76.52%	Support 8/12/13		
406	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Initial Ballot	8/2/2013	8/12/2013	Quorum: 76.32% Approval: 62.74%	Support 8/9/13		
407	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	8/2/2013	8/12/2013	Quorum: 75.89% Approval: 55.45%			
409	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Initial Ballot	8/14/2013	8/23/2013	Quorum: 78.33% Approval: 79.42%	Support 8/23/13		
410	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Non-binding Poll	8/14/2013	8/23/2013	Quorum: 77.45% Approval: 81.37%			
411	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Ballot	8/16/2013	8/26/2013	Quorum: 76.14% Approval: 51.10%	No Consensus 8/26/13		NPCC to support with comments
412	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Non-binding Poll	8/16/2013	8/26/2013	Quorum: 75.98% Approval: 53.29%			
413	Project 2010-01	Project 2010-01 - Training - PER-005-2	Ballot	8/23/2013	9/3/2013	Quorum: 75.25% Approval: 34.46%	No Consensus 8/31/13		NPCC to support with comments The most contentious issues raised by RSC members was surrounding the Control Center definition and the potential to vastly expand those needing training subject to the standard and compliance and that there was no need for a standard, rather, the FERC Directives should be addressed through other means.
414	Project 2010-01	Project 2010-01 - Training - PER-005-2	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 80.45% Approval: 34.24%			
415	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Ballot	8/23/2013	9/3/2013	Quorum: 81.89% Approval: 43.79%	Oppose 8/31/13		The standard, in the view of the group, has extensive issues including but not limited to, applicability issues, lacks clarity, missing measures, quality, and other substantive issues. NPCC will be submitting detailed comments to address these issues. The RSC does not believe it would be beneficial to support the standard at this point as the next step, if it fails the initial ballot, would still require an additional ballot prior to moving to recirculation due to the substantive changes that are needed for the next revision. NPCC will be submitting helpful comments to NERC and supporting the drafting team effort.
416	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 79.95% Approval: 44.23%			
417	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Ballot	8/26/2013	9/4/2013	Quorum: 82.29% Approval: 41.24%	Support 8/31/13		
418	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 79.66% Approval: 40.00%			
419	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Ballot	8/26/2013	9/4/2013	Quorum: 81.96% Approval: 55.76%	Support 8/31/13		
420	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 80.35% Approval: 58.97%			

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421	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	8/26/2013	9/4/2013	Quorum: 78.68% Approval: 66.11%	Support 8/31/13		
426	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Final Ballot	9/4/2013	9/13/2013	Quorum: 85.93% Approval: 90.83%	Support 8/5/13		
422	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Ballot	9/6/2013	9/16/2013	Quorum: 76.15% Approval: 58.23%	No Consensus 9/12/13		
423	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Non-binding Poll	9/6/2013	9/16/2013	Quorum: 75.69% Approval: 59.66%			
424	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Final Ballot	9/11/2013	9/20/2013	Quorum: 91.64% Approval: 98.61%	Support 3/14/13		
425	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Final Ballot	9/11/2013	9/20/2013	Quorum: 90.98% Approval: 98.92%	Support 3/14/13		
427	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Additional Ballot	10/9/2013	10/21/2013	Quorum: 77.58% Approval: 88.75%	Support 10/16/13		
428	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	10/9/2013	10/21/2013	Quorum: 75.89% Approval: 90.04%			
429	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Final Ballot	10/16/2013	10/25/2013	Quorum: 85.71% Approval: 85.38%			
430	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	10/18/2013	10/29/2013	Quorum: 75.83% Approval: 72.55%	Support 10/21/13		
431	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Final Ballot	10/25/2013	11/4/2013	Quorum: 86.90% Approval: 91.95%			
432	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	10/25/2013	11/7/2013	Quorum: 76.67% Approval: 58.24%	No Consensus 11/1/13		
433	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	11/1/2013	11/12/2013	Quorum: 76.23% Approval: 56.48%	Support 11/11/13		
434	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Initial Ballot	11/4/2013	11/13/2013	Quorum: 76.12% Approval: 67.35%	Support 11/5/13		
435	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-006-4	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 75.58%	Support 11/5/13		
436	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-009-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 68.40%	Support 11/5/13		
437	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 58.03%	Support 11/5/13		
438	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-011-1	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.52% Approval: 71.35%	Support 11/5/13		
439	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Initial Ballot	11/4/2013	11/15/2013	Quorum: 76.42% Approval: 77.82%	Support 11/5/13		
440	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Final Ballot	11/8/2013	11/18/2013	Quorum: 81.68% Approval: 74.34%	Support 10/21/13		
441	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Additional Ballot	11/8/2013	11/20/2013	Quorum: 81.69% Approval: 82.97%	No Consensus 8/26/13		
442	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.05% Approval: 73.46%	Support 8/31/13		
443	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.84% Approval: 69.42%	Support 8/31/13		
444	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	11/13/2013	11/22/2013	Quorum: 80.54% Approval: 57.59%	Support 8/31/13		
445	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Additional Ballot	11/15/2013	11/25/2013	Quorum: 80.81% Approval: 69.43%			
446	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	11/15/2013	11/25/2013	Quorum: 81.06% Approval: 66.09%			
447	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2	Additional Ballot	12/2/2013	12/12/2013	Quorum: 75.29% Approval: 64.24%	No Consensus 12/9/13	Affirmative	

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448	Project 2007-11	Project 2007-11 Disturbance Monitoring - PRC-002-2	Initial Ballot	12/6/2013	12/16/2013	Quorum: 82.25% Approval: 43.29%	No Consensus 12/15/13	Affirmative	Highlights of comments received expressed: • Agreement with the methodology to determine BES locations for which data had to be captured • Use of the term "locations" • DDR for Flowgates, IROLs • Clarification needed for some data that is to be captured • Editorial suggestions
449	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Final Ballot	12/6/2013	12/16/2013	Quorum: 87.53% Approval: 77.49%	Support 8/31/13	Affirmative	
450	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-006-4	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 80.77%	Support 11/5/13	Affirmative	
451	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-009-2	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 72.86%	Support 11/5/13	Affirmative	
452	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-011-1	Final Ballot	12/10/2013	12/20/2013	Quorum: 84.78% Approval: 72.91%	Support 11/5/13	Affirmative	
453	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Final Ballot	12/11/2013	12/20/2013	Quorum: 87.16% Approval: 86.40%	No Consensus 8/26/13	Affirmative	
454	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Final Ballot	12/13/2013	12/23/2013	Quorum: 84.34% Approval: 75.35%		Affirmative	
455	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-027-1	Additional Ballot	12/9/2013	12/31/2013	Quorum: 76.60% Approval: 65.71%	No Consensus 12/27/13	Affirmative	
456	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	1/10/2014	1/21/2014	Quorum: 76.92% Approval: 81.41%	Support 8/31/13	Affirmative	
457	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	1/8/2014	1/22/2014	Quorum: 7912% Approval: 74.63%	Support 11/11/13	Affirmative	
458	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 81.19%	Support 11/5/13	Affirmative	
459	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 90.23%	Support 11/5/13	Affirmative	
460	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Additional Ballot	1/16/2014	1/29/2014	Quorum: 76.12% Approval: 92.17%	Support 11/5/13	Affirmative	
461	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	1/22/2014	1/31/2014	Quorum: 76.03% Approval: 71.86%	No Consensus 11/1/13	Affirmative	Ballot Period Extended to 2/4/14
462	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.88% Approval: 83.44%	Support 11/5/13	Affirmative	
463	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.58% Approval: 91.51%	Support 11/5/13	Affirmative	
464	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Final Ballot	1/27/2014	2/5/2014	Quorum: 82.49% Approval: 82.45%	Support 8/31/13	Affirmative	
465	Project 2010-01	Project 2010-01 - Training - PER-005-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 84.02% Approval: 77.06%	Support 11/11/13	Affirmative	
466	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Final Ballot	1/31/2014	2/10/2014	Quorum: 81.79% Approval: 90.12%	Support 11/5/13	Affirmative	
467	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Additional Ballot	2/21/2014	3/3/2014	Quorum: 75.06% Approval: 62.63%	Support 9/5/12	Affirmative	Ballot Period Extended to 3/11/14
468	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Final Ballot	3/28/2014	4/7/2014	Quorum: 78.21% Approval: 77.62%	Support 3/28/14	Affirmative	
469	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	4/1/2014	4/10/2014	Quorum: 76.92% Approval: 83.40%	Support 8/31/13	Affirmative	
470	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	4/4/2014	4/14/2014	Quorum: 78.03% Approval: 82.40%		--	
471	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	Initial Ballot	4/20/2014	4/24/2014	Quorum: 88.60% Approval: 82.07%	Support 4/23/14	Abstain	
472	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Final Ballot	4/25/2014	5/5/2014	Quorum: 80.37% Approval: 90.00%	Support--4/25/14	Affirmative	
473	Project 2013-04	Project 2013-04 - Voltage and Reactive Control - VAR-001-4, VAR-002-3	Final Ballot	4/23/2014	5/5/2014	Quorum: 83.84% Approval: 88.26%	Support--4/10/14	Affirmative	
474	Project 2014-04	Project 2014-04 - Physical Security - CIP-014-1	Final Ballot	5/1/2014	5/5/2014	Quorum: 92.53% Approval: 85.61%	Support--4/23/14	Abstain	
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Initial Ballot	5/6/2014	5/15/2014	Quorum: 85.79%/79.08% Approval: 86.28%/78.81%	No Consensus--5/15/14	Reject	

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476	Project 2012-13	Project 2012-13 - NUC - Nuclear Plant Interface Coordination	Initial Ballot	5/13/2014	5/22/2014	Quorum: 80.60% Approval: 97.36%	Support--5/20/14	Affirmative		
477	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) - PRC-005-X	Initial Ballot	5/23/2014	6/2/2014	Quorum: 85.42% Approval: 47.89%	Support	Affirmative		
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Initial Ballot	5/30/2014	6/9/2014	Quorum: 79.06% Approval: 17.02%	Does not Support--6/6/14	Negative		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Final Ballot	6/12/2014	6/23/2014	Quorum: Approval: 89.03%/83.46%	Support	Affirmative		
479	Project 2007-11	Project 2007-11 - Disturbance Monitoring - PRC-002-2	Additional Ballot	6/13/2014	6/23/2014	Quorum: 77.69% Approval: 52.29%	Support	Affirmative	Extended to achieve a quorum.	
480	Project 2010-05.1	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Additional Ballot	6/20/2014	7/9/2014	Quorum: 76.98% Approval: 74.53%	Support	Affirmative	Extended to achieve a quorum.	Last RSC Meeting
481	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Ballot	6/23/2014	7/2/2014	Quorum: 82.32%/82.59%/82.59%/82.85%/82.85%/82.06%/82.59%/82.85%/82.85%/81.00%/80.74% Approval: 68.57%/36.94%/47.87%/60.26%/61.67%/57.94%/30.99%/62.18%/63.07%/62.64%/64.70%	No Consensus--6/24/14	Affirmative Negative Affirmative Affirmative Affirmative Affirmative Negative Affirmative Affirmative		
482	Project 2012-13	Project 2012-13 NUC - Nuclear Plant Interface Coordination	Final Ballot	6/24/2014	7/3/2014	Quorum: 88.63% Approval: 97.23%	Support--6/23/14	Affirmative		
483	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions Rich HTML Content 1 http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/16/2014	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29% Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 Yes CIP-010 Yes CIP-011 Yes Definitions Yes Support--7/14/14			
484	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Final Ballot	7/16/2014	7/25/2014	Quorum: 78.92% Approval: 58.88%	Support--7/23/14			
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.49%/80.15%/80.00%/80.83%/80.36% Approval: 91.38%/92.20%/89.51%/90.58%/87.09%	Support--7/24/14	Affirmative		
486	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 82.67% Approval: 55.77%		Affirmative		
487	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Initial Ballot	7/29/2014	8/7/2014	Quorum: 76.37% Approval: 76.91%		Affirmative		
488	Project 2012-13	Project 2009-03 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.66% Approval: 42.27%	Negative--8/14/14	Negative		
489	Project 2014-01	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.94% Approval: 79.75%	Support	Affirmative		
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 85.32%/86.01% Approval: 95.35%/95.86%	Support	Affirmative		
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3	Additional Ballot	9/3/2014	9/12/2014	Quorum: 84.33% Approval: 76.03%	Support--9/4/14	Affirmative		
492	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Additional Ballot	9/10/2014	9/19/2014	Quorum: 85.75%/84.96%/84.96%/85.22%/84.96%/85.22%/85.49%/85.22%/86.28%/83.11%/83.91%	TOP-001-3: Negative TOP-002-4: Affirmative TOP-003-3: Affirmative IRO-001-4: No consensus however the majority indicated an Affirmative vote IRO-002-4: Negative			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
						Approval: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%	IRO-008-2: No consensus, a majority indicated a Negative and the others indicated abstention IRO-010-2: Affirmative IRO-014-3: Negative IRO-017-1: Affirmative Implementation Plan and Definitions: Affirmative 9/18/14		
493	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	9/23/2014	10/2/2014	Quorum: 79.94% Approval: 46.73%	Negative--10/1/14		
494	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	9/26/2014	10/6/2014	Quorum: 79.01% Approval: 53.02%	Affirmative--10/1/14		
495	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Additional Ballot	9/29/2014	10/8/2014	Quorum: 83.24%/84.82% Approval: 80.69%/84.05%	Affirmative--10/7/14	Affirmative	
496	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	10/1/2014	10/10/2014	Quorum: 82.93% Approval: 57.95%	Affirmative--10/7/14		
497	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Additional Ballot	10/3/2014	10/14/2014	Quorum: 80.54% Approval: 75.79%	Affirmative--10/7/14		
498	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/7/2014	10/16/2014	Quorum: 81.91%/82.12% Approval: 94.92%/94.37%	Affirmative--10/14/14		
499	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Additional Ballot	10/8/2014	10/17/2014	Quorum: 84.63%/84.15%/84.15%/83.90%/83.41%/83.66%/83.96%/84.49%/83.96%/83.96%/84.22 Approval: 93.21%/68.09%/74.25%/79.91%/85.68%/89.01%/91.79%/81.34%/96.63%/96.63%/95.52%/85.93%/98.13%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative	CIP-003-6 and CIP-010-2 Affirmative	
500	Project 2009-03	Project 2009-03 Emergency Operations	Additional Ballot	10/10/2014	10/20/2014	Quorum: 80.93% Approval: 70.41%	Affirmative--10/17/14		
501	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (IRO-001-4, IRO-002-4, IRO-010-2, two Definitions, and Implementation Plan)	Final Ballot	10/10/2014	10/20/2014	Quorum: 90/77%/89.97%/89.97%/88.39%/88.39% Approval: 82.64%/85.96%/86.22%/94.07%/91.84%	Affirmative--10/17/14		
502	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3, and IRO-017-1)	Final Ballot	10/10/2014	10/20/2014	Quorum: 89.71%/88.39%/89.71%/89.71%/89.97% 84.76%/86.55%/83.73%/89.88%/82.58%	Affirmative--10/17/14		
503	Project 2007-11	Project 2007-11 Disturbance Monitoring	Additional Ballot	10/10/2014	10/21/2014	Quorum: 77..69% Approval: 71.38%	Affirmative--10/17/14		
504	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/10/2014	10/22/2014	Quorum: 85.13%/83.29% Approval: 94.75%/93.98%	Affirmative--10/20/14		
505	Project 2014-03	Project 2007-17.3 (PRC-005-X) Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays)	Final Ballot	10/20/2014	10/29/2014	Quorum: 88.25% Approval: 74.14%	Affirmative--10/28/14		
506	Project 2014-03	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.53% Approval: 83.12%	Affirmative--10/31/14		
507	Project 2007-11	Project 2007-11 Disturbance Monitoring	Final Ballot	10/28/2014	11/6/2014	Quorum: 81.89% Approval: 68.51%	Affirmative--10/31/14		
508	Project 2007-11	Project 2010-05.2 Phase 2 of Special Protection Systems	Final Ballot	10/28/2014	11/6/2014	Quorum: 85.41% Approval: 73.33%	Negative--10/14/14		
509	Project 2007-11	Project 2009-03 Emergency Operations	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.19% Approval: 73.20%	Affirmative--10/17/14		

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510	Project 2007-11	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	10/28/2014	11/6/2014	Quorum: 89.49%/87.66%/87.08 % Approval: 92.91%/92.15%/95.62 %	Affirmative--10/20/14		
511	Project 2014-03	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.56%/87.32%87.07 %/87.56%/87.80%87. 56%86.59% Approval: 83.84%/95.34%/86.00 %/95.35%91.17%/83. 88%/95.40%/92.76%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative		
512	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	11/4/2014	11/10/2014	Quorum: 78.36% Approval: 60.21%	Affirmative--11/4/14		
513	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	11/12/2014	11/21/2014	Quorum: 79.73% Approval: 77.29%	Affirmative--11/21/14		
514	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	11/14/2014	11/24/2014	Quorum: 79.83% Approval: 67.39%	Affirmative--10/1/14		
515	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.27% Approval: 78.05%	Affirmative--12/12/14		
516	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.81% Approval: 68.08%	Affirmative--12/15/14		
517	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Initial Ballots	12/10/2014	12/23/2014	Quorum: 79.38%/79.72%/79.60 % Approval: 92.69%/93.55%/93.67 %	Affirmative--12/22/14		
518	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	12/19/2014	1/7/2015	Quorum: 80.47% Approval: 72.43%	Affirmative--1/6/15		
519	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions	Additional Ballot	12/30/2014	1/9/2015	Quorum: 81.22%/81.71%/81.46 %/81.71%/81.71%/81. 22%/81.71%/81.46% Approval: 81.92%/98.89%/98.86 %/88.13%/98.89%/86. 02%/89.63%/97.21%	CIP-003-7 Binding and non-binding polls-no consensus CIP-003-7 Definition-Affirmative CIP-010-7 Binding and non-binding polls- Affirmative CIP-010-7 Definition- Affirmative CIP-004-7 Binding and non-binding polls – Affirmative CIP-007-7 Binding and non-binding polls –Affirmative CIP-011-7 Binding and non-binding polls –Affirmative CIP Implementation Plan- Affirmative 1/8/2015		
520	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards - TOP-001-3	Final Ballots	1/15/2015	1/21/2015	Quorum: 84.70% Approval: 72.69%	Affirmative--1/6/15		
521	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Initial Ballots	1/12/2015	1/22/2015	Quorum: 77.93% Approval: 93.74%	Affirmative--1/22/15		
522	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-001-1.1(ii), PRC-019-2, and PRC-024-2	Final Ballots	1/13/2015	1/22/2015	Quorum: 89.27%/89.30%/89.52 % Approval: 93.99%/94.03%/95.82 %	Affirmative--1/22/15		
523	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions CIP-003-7, CIP-004-7, CIP-010-3, and CIP-011-3	Final Ballot	1/23/2015	2/2/2015	Quorum: 84.15%/84.39%/84.15 %/84.39%/84.39%/83. 90%/84.39%/83.66% Approval: 79.76%/98.94%/98.94 %/86.76%/98.93%/84. 07%/90.10%/97.32%	Affirmative--1/29/15		
524	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Final Ballot	3/2/2015	3/11/2015	Quorum: 83.52% Approval: 98.03%	Affirmative--1/22/15		
525	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	3/6/2015	3/16/2015	Quorum: 77.29% Approval: 59.30%	Negative--3/13/2015		
526	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Initial Ballot	3/27/2015	4/7/2015	Quorum: 79.93% Approval: 84.31%	Affirmative--3/31/15		

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527	Project 2014-04	Project 2014-04 Physical Security	Initial Ballot	3/31/2015	4/9/2015	Quorum: 88.33% Approval: 89.95%	Affirmative--3/31/15		
528	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Final Ballot	4/17/2015	4/27/2015	Quorum: 84.86% Approval: 89.63%	Affirmative--3/31/15		
529	Project 2014-04	Project 2014-04 Physical Security	Final Ballot	4/20/2015	4/29/2015	Quorum: 92.00% Approval: 92.35%	Affirmative--3/31/15		
530	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	5/6/2015	5/15/2015	Quorum: 81.79% Approval: 39.63%	Negative--5//13/15		
531	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Initial Ballot	6/29/2015	7/8/2015	Quorum: 75.23%/84.00% Approval: 90.35%/97.50%	Affirmative--7/7/15		
532	Project 2015-04	2015-04 Alignment of Terms	Initial Ballot	7/17/2015	7/27/2015	Quorum: 90.43%/91.17%/91.10%/91.01%/91.10%/91.17%/91.17%/91.34%/90.97%/91.40%/90.10%/91.01%/91.07%/91.07%/91.07%/91.34%/91.43%/90.75%/91.34%/91.01%/91.40%/91.01%/91.01%/91.01%/91.01%/91.01% Approval: 91.46%/88.57%/86.68%/97.06%/97.10%/81.06%/80.73%/96.38%/97.03%/69.80%/95.38%/93.62%/96.83%/97.00%/98.55%/87.37%/89.99%/84.38%/88.06%/90.37%/97.75%/91.28%/87.71%/89.44%/87.15%/98.24%	Affirmative--7/24/15		
533	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Final Ballots	7/22/2015	7/31/2015	Quorum: 85.98%/90.67%% Approval: 88.23%/96.84%	Affirmative--7/7/15		
534	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	8/11/2015	8/20/2015	Quorum: 75.92% Approval: 69.26%	Affirmative--8/17/15		
535	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	9/2/2015	9/11/2015	Quorum: 84.34% Approval: 69.76%	Affirmative--9/8/15		
536	Project 2007-06	Project 2007-06.2 Phase 2 of System Protection Coordination	Initial Ballot	9/2/2015	9/11/2015	Quorum: 87.16% Approval: 62.55%	Affirmative--9/11/15		
537	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Initial Ballot	9/4/2015	9/14/2015	Quorum: 83.81% Approval: 55.97%	Abstention--9/14/15		
538	Project 2015-04	2015-04 Alignment of Terms	Final Ballot	9/4/2015	9/14/2015	Quorum: 96.81%/97.53%/97.51%/97.48%/97.51%/97.53%/97.53%/97.11%/97.11%/97.85%/96.80%/97.12%/97.14%/97.14%/97.14%/97.11%/97.14%/96.80%/97.11%/97.48%/97.85%/97.48%/97.48%/97.48%/97.48%/97.48%	Affirmative--7/24/15		

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						Approval: 93.13%/92.89%/91.33%/98.07%/98.07%/84.78%/84.75%/98.30%/98.06%/75.63%/95.46%/94.48%/98.31%/97.11%/98.57%/90.80%/95.60%/90.46%/92.07%/92.49%/97.81%/92.84%/91.09%/91.32%/90.80%/98.29%	Affirmative--7/24/15		
539	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	Initial Ballot	9/4/2015	9/16/2015	Quorum: 86.97% Approval: 96.73%	Affirmative--9/16/15		
540	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	Initial Ballot	9/9/2015	9/18/2015	Quorum: 85.57% Approval: 87.36%	Affirmative--9/18/15		
541	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Initial Ballot	9/25/2015	10/5/2015	Quorum: 83.70% Approval: 48.10%	N egative--10/2/15		
542	Project 2010-05.3	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Final Ballot	9/29/2015	10/8/2015	Quorum: 84.28% Approval: 74.61%	Affirmative--8/17/15		
543	Project 2010-05.3	Project 2007-06 System Protection Coordination	Final Ballot	10/5/2015	10/14/2015	Quorum: 89.16% Approval: 80.94%	Affirmative--9/8/15		
544	Project 2010-05.3	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	Final Ballot	10/6/2015	10/15/2015	Quorum: 89.60% Approval: 90.01%	Affirmative--9/18/15		
545	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	Final Ballot	10/15/2015	10/26/2015	Quorum: 90.00% Approval: 96.38%	Affirmative--9/16/15		
546	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Initial Ballot	10/30/2015	11/9/2015	Quorum: 84.59%/84.49% Approval: 47.38%/48.00%	Abstention--11/5/15		
547	Project 2010-05.3	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Initial Ballot	11/3/2015	11/12/2015	Quorum: 84.40% Approval: 98.17%	Affirmative--11/5/15		
548	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Initial Ballot	11/6/2015	11/16/2015	Quorum: 88.18% Approval: 53.60%	Affirmative--11/13/15		
549	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Additional Ballot	11/10/2015	11/19/2015	Quorum: 83.18% Approval: 57.29%	Affirmative--11/18/15		
550	Project 2010-07.1	Project 2010-07.1 Vegetation Management	Initial Ballot	12/7/2015	12/16/2015	Quorum: 85.38% Approval: 82.56%	Negative--12/8/15		
547	Project 2010-05.3	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Final Ballot	12/8/2015	12/17/2015	Quorum: 88.65% Approval: 98.26%	Affirmative--11/5/15		
551	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	12/30/2015	1/8/2016	Quorum: 83.39%/80.88% Approval: 60.39%/92.94%	Affirmative--12/3015		
552	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Additional Ballot	12/31/2015	1/11/2016	Quorum: 84.13%/83.17%/84.44% Approval: 70.64%/75.54%/94.30%	BAL-005-1--Negative--1/10/16 BAL-006--Affirmative--1/10/16 FAC-003-1--Abstention--1/10/16		
553	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Additional Ballot	1/15/2016	1/25/2016	Quorum: 82.88%/82.18% Approval: 72.13%/68.01%	Affirmative--1/25/16		
554	Project 2010-07.1	Project 2010-07.1 Vegetation Management	Final Ballot	1/29/2016	2/8/2016	Quorum:90.03% Approval: 96.18%	Affirmative--2/1/16		
552	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Final Ballot	1/29/2016	2/8/2016	Quorum: 86.35%/86.98%/86.67% Approval: 72.06%/94.61%/80.15%	Affirmative--2/3/15		
551	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Final Ballot	2/17/2016	2/26/2016	Quorum: 88.36%/87.79% Approval: 75.68%/73.87%	Affirmative--1/25/16		
552	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	3/9/2016	3/18/2016	Quorum: 75.55%	Affirmative--3/10/16		

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						Approval: 78.87%			
553	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Initial Ballot	4/15/2016	4/25/2016	Quorum: 83.39%/83.33% Approval: 80.57%/78..39%	Affirmative--4/20/16		
554	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Final Ballot	4/20/2016	4/29/2016	Quorum: 81.19%/87.15% Approval: 80.36%/93.43%	Affirmative--3/10/16		
555	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Additional Ballot	4/27/2016	5/6/2016	Quorum: 81.03% Approval: 82.64%	Affirmative--5/6/16		
556	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Final Ballot	5/17/2016	5/26/2016	Quorum: 88.96%/88.36% Approval: 82.52%/83.37%	Affirmative--4/20/16		
557	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Final Ballot	6/15/2016	6/24/2016	Quorum: 84.52% Approval: 83.25%	Affirmative--5/6/16		
558	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Initial Ballot	7/25/2016	8/3/2016	Quorum: 84.50%/85.51% Approval: 67.25%/64.59%	Affirmative--8/1/16		
559	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3 EOP-006-3 EOP-008-2	Initial Ballot	8/4/2016	8/15/2016	Quorum: 80.45%/81.14%/80.79% Approval: 52.90%/66.87%/84.13%	Negative--8/4/16		
560	Project 2016-02	Project 2016-02 Modifications to CIP Standards	Initial Ballot	8/26/2016	9/6/2016	Quorum: 85.00%/84.37%/84.62% Approval: 41.54%/41.77%/30.63%	Negative--9/6/16		
561	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Initial Ballot	8/30/2016	9/8/2016	Quorum: 82.75% Approval: 80.32%	Affirmative--9/8/16		
562	Project 2015-INT-01	Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	Initial Ballot	9/2/2016	9/12/2016	Quorum: 75.43% Approval: 91.68%	Affirmative--9/12/16		
563	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Additional Ballot	10/5/2016	10/14/2016	Quorum: 83.33%/81.79% Approval: 70.77%/68.85%	Affirmative--10/13/16		
564	Project 2015-INT-01	Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	Final Ballot	10/13/2016	10/24/2016	Quorum: 81.25% Approval: 91.31%	Affirmative--9/12/16		
565	Project 2016-02	Project 2016-02 Modifications to CIP Standards	Additional Ballot	11/23/2016	12/5/2016	Quorum: 76.40%/76.63% Approval: 85.56%/75.54%	Affirmative--12/1/16		
566	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3 and EOP-006-3	Additional Ballot	11/30/2016	12/9/2016	Quorum: 80.71%/82.43% Approval: 76.93%/77.17%	Affirmative--11/30/16		
567	Project 2015-08	Project 2015-08 Emergency Operations EOP-008-2	Final Ballot	11/30/2016	12/9/2016	Quorum: 93.36% Approval: 93.17%	Affirmative--11/30/16		
568	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Final Ballot	12/2/2016	12/12/2016	Quorum: 90.74%/90.40% Approval: 74.30%/72.52%	Affirmative--12/2/16		
569	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7 and Implementation	Final Ballot	12/9/2016	12/19/2016	Quorum: 82.89%/83.14% Approval: 87.95%/83.03%	Affirmative--12/1/16		
570	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Additional Ballot	12/28/2016	1/6/2017	Quorum: 79.47% Approval: 93.55%	Affirmative--1/4/17		
571	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3, EOP-006-3	Final Ballot	12/28/2016	1/6/2017	Quorum: 91.00%/91.55% Approval: 83.65%/80.56%	Affirmative--1/4/17		

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572	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7(i) Implementation Plan and 2 Definitions	Initial Ballot	1/16/2017	1/25/2017	Quorum: 77.81%/76.71%/77.26%/76.71% Approval: 81.30%/87.87%/86.75%/86.47%	Affirmative--1/23/17		
573	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Initial Ballot	2/24/2017	3/6/2017	Quorum: 87.13% Approval: 10.36%	Abstain--3/2/17		
574	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Final Ballot	1/24/2017	2/2/2017	Quorum: 84.46% Approval: 93.80%	Affirmative--1/4/17		
575	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7(i) Implementation Plan and 2 Definitions	Final Ballot	1/30/2017	2/8/2017	Quorum: 86.58%/85.48%/86.03%/85.48% Approval: 78.55%/86.00%/85.81%/85.54%	Affirmative--1/23/17		
576	SPM	Revisions to the NERC Standards Process Manual	Initial Ballot	4/24/2017	5/3/2017	Quorum: 78.21% Approval: 64.72%			
577	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Additional Ballot	6/6/2017	6/15/2017	Quorum: 76.02%/76.02%/77.21% Approval: 89.84%/82.92%/88.64%	Affirmative--6/8/17		
578	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Final Ballot	7/11/2017	7/20/2017	Quorum: 81.59%/81.33%/82.84% Approval: 88.79%/81.40%/84.19%	Affirmative--6/8/17		
579	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Initial Ballot	8/2/2017	8/11/2017	Quorum: 79.87% Approval: 72.67%	Affirmative--8/3/17		
580	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Initial Ballot	8/29/2017	9/8/2017	Quorum: 80.45% Approval: 78.79%	Affirmative--9/1/17		
581	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1 Control Center Communication Networks	Initial Ballot	8/14/2017	9/12/2017	Quorum: 80.00% Approval: 42.74%	Affirmative--9/1/17		
582	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Initial Ballot	9/8/2017	10/23/2017	Quorum: 82.71% Approval: 30.50%	Abstain--10/18/17		
583	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Final Ballot	10/20/2017	10/30/2017	Quorum: 88.74% Approval: 73.35%	Affirmative--8/3/17		
584	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Initial Ballot	9/14/2017	10/30/2017	Quorum: 85.40% Approval: 66.78%	Affirmative--10/30/17		
585	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Initial Ballot	11/3/2017	11/13/2017	Quorum: 87.01%/86.90%/86.90%/85.57%/85.85 Approval: 58.12%/63.17%/56.55%/76.40%/68.59%	Affirmative--11/10/17		
586	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	11/20/2017	12/11/2017	Quorum:77.10% Approval: 63.91%	Affirmative--12/4/17		
587	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Additional Ballot	10/30/2017	12/13/2017	Quorum: 81.73% Approval: 88.25%	Affirmative--12/4/17		
588	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Final Ballot	1/9/2018	1/18/2018	Quorum: 82.69% Approval: 89.46%	Affirmative--12/4/17		
589	Project 2017-02	Project 2017-02 Modifications to Personnel Performance, Training and Qualifications	Initial Ballot	2/26/2018	3/7/2018	Quorum: 80.93%/81.27% Approval: 97.50%/98.91%	Affirmative--3/2/18		
590	Project 2017-02	Project 2017-02 Modifications to Personnel Performance, Training and Qualifications	Final Ballot	4/3/2018	4/12/2018	Quorum: 84.82%/84.86% Approval: 96.64%/97.88%	Affirmative--3/2/18		
591	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Additional Ballot	2/23/2018	4/23/2018	Quorum: 80% Approval: 26.44%	Affirmative--4/16/18		
592	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Additional Ballot	3/16/2018	4/30/2018	Quorum: 79.50% Approval: 93.31%	Affirmative--4/25/18		
593	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	3/16/2018	4/30/2018	Quorum:78.06% Approval: 83.71%	Affirmative--4/25/18		

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594	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1 Control Center Definition and Implementation Plan	Initial Ballot	3/16/2018	4/30/2018	Quorum: 81.33%/81.54% Approval: 46.71%/37.98%	Negative--4/25/18		
595	Project 2017-06	Project 2017-06 Modifications to BAL-002-2	Initial Ballot	4/27/2018	5/8/2018	Quorum: 81.82% Approval: 80%	Abstain--5/7/17		
596	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	5/18/2018	7/3/2018	Quorum: 75.16% Approval: 68.45%	Affirmative--6/29/18		
597	Project 2017-06	Project 2017-06 Modifications to BAL-002-2	Final Ballot	7/5/2018	7/16/2018	Quorum: 84.42% Approval: 71.85%	Abstain--5/7/17		
598	SPM	Revisions to the NERC Standards Process Manual	Additional Ballot	7/31/2018	8/9/2018	Quorum: 80.34% Approval: 81.95%	Affirmative--8/7/18		
599	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Final Ballot	8/3/2018	8/13/2018	Quorum:81.55% Approval: 72..55%	Affirmative--4/25/18		
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		
601	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Initial Ballot	9/28/2018	10/9/2018	Quorum: 78.59% Approval: 55.89%	Affirmative--10/5/18		
602	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-003-8	Initial Ballot	9/28/2018	10/9/2018	Quorum: 78.77% Approval: 90.06%	Affirmative--10/5/18		
603	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Additional Ballot	10/8/2018	10/17/2018	Quorum: 83.65%/84.08%/83.77%/84.82%/82.43%/82.11%/84.08%/83.60%/83.12%/80.98%/83.28% Approval: 67.65%/67.46%/53.22%/77.07%/59.02%/59.79%/75.07%/69.27%/71.98%/69.93%/82.26%	Affirmative--10/12/18		
604	Project 2018-02	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Initial Ballot	10/18/2018	10/22/2018	Quorum: 81.17% Approval: 20.02%	Reject--10/22/18		
605	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Final Ballot	10/11/2018	10/22/2018	Quorum: 86.39% Approval: 66.69%	Affirmative--9/5/18		
606	SPM	Revisions to the NERC Standards Process Manual	Final Ballot	10/7/2018	10/29/2018	Quorum: 85.96% Approval: 81.61%	Affirmative--8/7/18		
607	Project 2018-01	Project 2018-01 Canadian-specific Revisions to TPL-007-2	Initial Ballot	11/6/2018	11/15/2018	Quorum: 77.54%/79.10% Approval: 100%/100%	Affirmative--11/6/18		
608	Project 2018-02	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Additional Ballot	11/20/2018	11/29/2018	Quorum: 94.44% Approval: 75.54%	Affirmative--11/20/18		
609	Project 2018-01	Project 2018-01 Canadian-specific Revisions to TPL-007-2	Final Ballot	11/29/2018	12/10/2018	Quorum: 80.43%/82.09% Approval: 100%/100%	Affirmative--11/6/18		
610	Project 2017-01	Project 2017-01 Modifications to BAL-003-1.1	Initial Ballot	1/8/2019	1/17/2019	Quorum: 92.02%/91% Approval: 96.41%/99.04%	Affirmative--1/14/19		
611	Project 2018-02	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Final Ballot	1/15/2019	1/22/2019	Quorum: 96.30% Approval: 77.89%	Affirmative--11/20/18		
612	Project 2018-03	Project 2018-03 Standards Efficiency Review Retirements	Initial Ballot	4/3/2019	4/12/2019	Quorum: 86.75%/87.96%/87.80%/87.58%/87.58%/87.50%/87.58%/87.34%/87.46%/86.45%/87.34%/86.77%/87.17%/87.17%/86.89%/85.71%/85.67%/86.39%	Affirmative--4/10/19 for all standards except three. Negative--4/10/19 on following standard: PRC-004-5(i), INT-010-		

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						Approval: 96.18%/98.88%/97.41%/97.79%/98.51%/89.75%/98.53%/96.60%/95.96%/96.60%/95.80%/98.95%/96.45%/96.54%/95.90%/88.42%/98.96%/97.69%	Negative--4/10/19 on following standard: PRC-004-5(i), INT-010-2.1 and FAC-0008-3		
613	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-003-8	Final Ballot	4/18/2019	4/29/2019	Quorum: 83.64% Approval: 91.44%	Affirmative--10/5/18		
614	Project 2018-03	Project 2018-03 Standards Efficiency Review Retirements	Final Ballot	4/3/2019	4/12/2019	Quorum: 90.22%/90.97%/90.85%/90.94%/90.94%/90.88%/90.60%/90.26%/90.43%/90.32%/90.26%/90.65%90.13%/90.13%/89.84%/90.06%/90.03%/89.56% Approval: 95.74%/86.66%/85.94%/96.64%/97.22%/90.19%/97.19%/95.47%/94.63%/94.34%/94.69%/96.59%95.28%/95.41%94.55%/87.12%/97.75%/96.57%	Affirmative--4/10/19 for all standards except three.		
615	Project 2018-04	Project 2018-04 Modifications to PRC-024-2	Initial Ballot	5/22/2019	5/31/2019	Quorum: 88.08% Approval: 52.28%	Abstain--5/29/19		
616	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Additional Ballot	6/3/2019	7/17/2019	Quorum: 85.40% Approval: 87.39%	Affirmative--7/15/19		

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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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
1.	N/A	Standards Project Prioritization Reference Document and Tool	Project Prioritization Tool		1/21/11	2/10/11	Yes 2/10/11
2.	Project 2007-23	Project 2007-23 - Violation Severity Levels	VSLs		1/20/11	2/18/11	Yes 2/18/11
3.	N/A	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	CAN-0015 Unavailability of NERC Tools		2/4/11	2/18/11	Yes 2/18/11
4	N/A	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	CAN-0016 CIP-001-1, R1		2/4/11	2/18/11	Yes 2/18/11
5.	N/A	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	CAN-0018 FAC-008, R.1.2.1		2/4/11	2/18/11	Yes 2/18/11
6.	Regional Standard	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		1/10/11	2/24/11	
7.	Project 2007-07	Project 2007-07 - Vegetation Management - FAC-003	FAC-003-2		1/27/11	2/28/11	Yes 2/28/11
8.	N/A	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	CAN-0017 CIP-007, R5		2/11/11	3/4/11	Yes 3/4/11
9.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1		2/4/11	3/7/11	Yes 3/7/11
10.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	COM-001 COM-002 IRO-001 IRO-014		1/18/11	3/7/11	Yes 3/7/11
11.	NERC RoP	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	RoP Section 1700		2/14/11	3/7/11	Yes 3/7/11
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11
14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	Yes 4/8/11
15.	RFC RoP	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments			3/1/11	4/15/11	
16.	NERC RoP	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Appendices 3B and 3D		3/1/11	4/15/11	Yes 4/15/11
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	Yes 4/27/11
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	Yes 5/2/11
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	Yes 5/9/11
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	Yes 5/27/11
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	Yes 5/31/11
22.	Project 2007-03	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	TOP-001 through TOP-008 and PER-001		4/26/11	6/9/11	Yes 6/9/11
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	Yes 6/10/11
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	Yes 6/10/11

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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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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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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

RSC Meeting #19-3, Agenda Item 6.3: Comment History

(As of 8/1/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Processes Manual					
336	Project 2015-10	Single Points of Failure	TPL-001-5	Informal	4/25/17	5/24/17	Yes 5/24/17
337	Project 2016-03	Cyber Security Supply Chain Risk Management	CIP-005-6 CIP-010-3 CIP-013-1	Formal	5/2/17	6/15/17	Yes 6/15/17
338	Project 2017-01	Modifications to BAL-003-1.1 SAR	BAL-003-1.1	Formal	6/19/17	7/18/17	Yes 7/18/17
339	Project 2017-06	Modifications to BAL-002-2 SAR	BAL-002-2	Informal	6/20/17	7/20/17	Yes 7/20/17
340	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications Standards	PER-003-1 PER-004-2	Informal	6/21/17	7/24/17	Yes 7/24/17
341	2018-2010	Reliability Standards Development Plan		Formal	6/22/17	7/25/17	Yes 7/26/17
342	Standards Grading	Periodic Review Standing Review Team	Standards Grading	Informal	6/19/17	8/2/17	Yes 8/2/17
343	Project 2013-03	Geomagnetic Disturbance Mitigation	TPL-007-2	Formal	6/28/17	8/11/17	Yes 8/11/17
344	Project 2017-07	Alignment with Registration	Registration	Formal	8/1/17	8/30/17	Yes 8/30/17
345	Project 2017-07	Alignment with Registration	MOD-032-1 SAR	Formal	8/1/17	8/30/17	Yes 8/30/17
346	Reliability Guideline	Area Control Error Diversity Interchange Process	ACE Process	Formal	7/18/17	8/31/17	Yes 8/31/17
347	Project 2016-04	Modifications to PRC-025-1	PRC-025-2	Formal	7/25/17	9/7/17	Yes 9/7/17
348	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	7/27/17	9/11/17	Yes 9/11/17
349	Project 2016-02	Modifications to CIP Standard	Technical Rationale and Justification for CIP-012-1	Informal	8/14/17	9/12/17	Yes 9/12/17
350	Project 2016-02	Modifications to CIP Standard	Definition of Control Center	Informal	8/14/17	9/12/17	Yes 9/12/17
351	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	9/8/17	10/23/17	Yes 10/23/17
352	Project 2016-02	Modifications to CIP Standard	CIP-002-6	Formal	9/14/17	10/30/17	Yes 10/30/17
353	Project 2015-09	Establish and Communicate System Operating Limits	Proposed Definitions of System Operating Limit (SOL) and SOL Exceedance	Informal	9/29/17	10/30/17	Yes 10/30/17
354	Project 2016-02	Modifications to CIP Standard	Virtualization	Informal	10/6/17	11/2/17	Yes 11/2/17
355	Project 2015-09	Establish and Communicate System Operating	FAC-010 FAC-011 FAC-014	Formal	9/29/17	11/13/17	Yes 11/13/17

RSC Meeting #19-3, Agenda Item 6.3: Comment History

(As of 8/1/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Limits					
356	Project 2017-01	Modifications to BAL-003-1.1	SAR	Formal	11/2/17	12/1/17	Yes 12/1/17
357	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	10/27/17	12/11/17	Yes 12/11/17
358	Project 2016-02	Modifications to CIP Standard	Technical Rationale/Justification	Informal	11/20/17	12/11/17	Yes 12/11/17
359	Project 2017-03	FAC-008-3 Periodic Review	FAC-008-3	Formal	10/30/17	12/13/17	Yes 12/13/17
360	Project 2016-04	Modifications to PRC-025-1	PRC-025-1	Formal	10/30/17	12/13/17	Yes 12/13/17
361	Project 2017-07	Alignment with Registration	SAR	Formal	12/11/17	1/9/18	Yes 1/9/18
362	Project 2017-05	NUC-001-3	NUC-001-3	Formal	12/15/17	1/29/18	Yes 1/29/18
363	Project 2017-04	INT Periodic Review	INT-004-3.1 INT-006-4 INT-009-2.1 INT-010-2.1	Formal	1/10/18	2/23/18	Yes 2/23/18
364	Project 2017-07	Standards Alignment with Registration	Multiple Standards	Formal	2/1/18	3/2/18	Yes 3/2/18
365	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications (PER) Standards	PER-003-1 PER-004-2	Formal	1/22/18	3/7/18	Yes 3/7/18
366	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	2/23/18	4/23/18	Yes 4/23/18
367	Project 2018-01	Canadian-specific Revisions to TPL-007-2 SAR	TPL-007-2 SAR	Formal	3/30/18	4/30/18	Yes 4/30/18
368	Project 2016-02	Modifications to CIP Standard	CIP-002-6	Formal	3/16/18	4/30/18	Yes 4/30/18
369	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	3/16/18	4/30/18	Yes 4/30/18
370	Project 2016-02	Modifications to CIP Standard	Control Center Definition and Implementation	Formal	3/16/18	4/30/18	Yes 4/30/18
371	Standards Grading	2018 Periodic Review Standing Review Team	Standard Grading	Informal	5/14/18	6/28/18	Yes 6/28/18
372	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	5/18/18	7/3/18	Yes 7/2/18
373	SER	Standard Efficiency Review	SAR	Informal	6/7/18	7/10/18	Yes 7/10/18
374	Project 2016-02	Modifications to CIP Standard	CIP-002-5.1a SAR	Informal	6/14/18	7/13/18	Yes 7/13/18
375	Project 2016-02	Modifications to CIP Standard	CIP-003-7 SAR Order 843	Informal	6/14/18	7/13/18	Yes 7/13/18
376	SPM	Standards Processes Manual	SPM	Formal	6/25/18	8/9/18	Yes 8/9/18

RSC Meeting #19-3, Agenda Item 6.3: Comment History

(As of 8/1/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
383	Project 2016-02	Modifications to CIP Standards	CIP-002-6	Formal	8/23/18	10/9/18	Yes 10/9/18
384	Project 2016-02	Modifications to CIP Standards	CIP-003-8	Formal	8/23/18	10/9/18	Yes 10/9/18
385	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010 FAC-011 FAC-014	Formal	8/24/18	10/17/18	Yes 10/17/18
386	Project 2018-02	Cyber Security – Incident Reporting and Response Planning	CIP-008-6	Formal	10/3/18	10/22/18	Yes 10/22/18
387	Project 2018-01	Canadian-specific Revisions to TPL-007-2	TPL-007-2	Formal	10/2/18	11/15/18	Yes 11/15/18
388	Project 2018-02	Cyber Security – Incident Reporting and Response Planning	CIP-008-6	Formal	11/15/18	11/29/18	Yes 11/29/18
389	Project 2016-02	Modifications to CIP Standards	Virtualization	Informal	11/2/18	12/18/18	Yes 12/18/18
390	Project 2017-01	Modifications to BAL-003-1.1	BAL-003-1.1	Formal	12/4/18	1/17/19	Yes 1/17/19
391	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Formal	12/19/18	1/18/19	Yes 1/18/19
392	Standard Efficiency Review	Standard Efficiency Review	SER Phase 2 Concepts Survey	Informal	2/22/19	3/22/19	Yes 3/22/19
393	Project 2019-01	Modifications to TPL-007-3	TPL-007-3	Informal	2/25/19	3/26/19	Yes 3/26/19
394	Project 2018-03	Standard Efficiency Review Retirements	FAC-008-4 INT-006-5 INT-009-3 IRO-002-6 PRC-004-6 TOP-001-5	Formal	2/27/19	4/12/19	Yes 4/12/19

RSC Meeting #19-3, Agenda Item 6.3: Comment History

(As of 8/1/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
			VAR-001-6 FAC-013-2 INT-004-3.1 INT-010-2.1 MOD-001-1a MOD-004-1 MOD-008-1 MOD-020-0 MOD-028-2 MOD-029-2a MOD-030-3 MOD-001-2				
395	Project 2019-02	BES Cyber System Information Access Management	CIP-004-6	Formal	3/28/19	4/26/19	Yes 4/26/19
396	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Formal	4/17/19	5/31/19	Yes 5/31/19
397	Project 2016-02	Modifications to CIP Standards	Virtualization White Paper	Informal	5/30/19	6/28/19	Yes 6/28/19
398	Project 2016-02	Modifications to CIP Standards	CIP-002-6	Formal	6/3/19	7/17/19	Yes 7/17/19
399	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Informal	6/27/19	7/26/19	Yes 7/26/19
400	Project 2019-03	Cyber Security Supply Chain Risks	CIP-005-6 CIP-010-3 CIP-013-1	Informal	7/2/19	8/1/19	Yes 8/1/19

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

NPCC, Inc.

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

February 15th, 2019

NPCC Full and General Members:

In accordance with the FERC approved NPCC Regional Standard Processes Manual, revisions were performed for the NPCC Regional Standard PRC-006-NPCC-02 Automatic Underfrequency Load Shedding. The Standard was posted for three open process comment periods and a pre-ballot review. A ballot was then conducted which closed at 23:59PM on February 10th, 2019.

The results of the ballot were as follows:

Quorum: 80.95% of the Total Registered NPCC General and Full Members Representatives
Approval: 76%

Requisite approval was attained for the ballot therefore a recommendation for final NPCC Regional approval will be sent to the NPCC Board of Directors for consideration at their meeting on May 1st, 2019.

Contingent upon the approval of the NPCC BOD, the proposal to approve PRC-006-NPCC-02 will be submitted to the NERC Board of Trustees for their consideration and adoption at their August 14-15, 2019 meeting. NERC and NPCC will then develop filings for the FERC and applicable provincial authorities for their review and final approval.

Voting was conducted electronically and the full record for the standard may be viewed, after signing in, at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=122

Thank you for your participation in the development of this important Standard to ensure the reliablity objectives of NPCC.

Ruida Shu
Northeast Power Coordinating Council, Inc.
Manager, Reliability Standards
Main: 212-840-1070
Direct: 917-934-7976
Fax: 212-302-2782
Email: rshu@npcc.org

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 1, Transmission Owners	**17**	**17**	**0**		**17**	**0**	**0**
Central Hudson Gas and Electric Corporation	1	1			1		
Central Maine Power Company	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Emera Maine	1	1			1		
Eversource Energy	1	1			1		
Hydro One Inc	1	1			1		
Hydro-Quebec TransEnergie	1	1			1		
Long Island Power Authority	1	1			1		
National Grid	1	1			1		
New Hampshire Transmission, LLC	1	1			1		
New York Power Authority	1	1			1		
New York State Electric & Gas Corporation	1	1			1		
Nova Scotia Power Inc.	1	1			1		
Orange and Rockland Utilities Inc	1	1			1		
Rochester Gas & Electric Corporation	1	1			1		
The United Illuminating Company	1	1			1		
Vermont Transco	1	1			1		

		1. Determine Quorum			2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 2, Reliability Coordinators	**5**	**5**	**0**		**5**	**0**	**0**
Hydro-Quebec TransEnergie	1	1			1		
Independent Electricity System Operator	1	1			1		
ISO-New England, Inc.	1	1			1		
New Brunswick Power Corporation	1	1			1		
New York Independent System Operator	1	1			1		

	1. Determine Quorum			2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**	**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 3, TDUs, Dist. And LSE	**21**	**17**	**2**	**19**	**0**	**0**
Braintree Electric Light Department	1	1		1		
Consolidated Edison Company of New York, Inc.	1	1		1		
Eversource Energy	1	1		1		
Groton Electric Light	1	1		1		
Hingham Municipal Lighting Plant	1	1		1		
Hydro One Inc	1		1	1		
Hydro Quebec Distribution	1		1	1		
Ipswich Municipal Light Department	1	1		1		
Long Island Power Authority	1	1		1		
Marblehead Municipal Light Department	1	1		1		
National Grid USA	1	1		1		
New Brunswick Power Corporation	1	1		1		
New York Power Authority	1	1		1		
Orange and Rockland Utilities, Inc	1	1		1		
Princeton Municipal Light Department	1					
Shrewsbury Electric & Cable Operations	1	1		1		
Sterling Municipal Light Department	1	1		1		
Toronto Hydro Electric System Ltd.	1	1		1		
Vermont Electric Cooperative, Inc.	1					
Wakefield Municipal Gas and Light Department	1	1		1		
Westfield Gas & Electric	1	1		1		

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 4, Generator Owners	**20**	**16**	**0**		**10**	**4**	**2**
Bruce Power L.P.	1						
Consolidated Edison Company of New York, Inc.	1	1			1		
Covanta Energy	1	1				1	
Dominion Resources, Inc.	1	1			1		
Eastern Generation LLC	1	1					1
Entergy Nuclear Northeast, Inc	1	1			1		
Exelon Generation Company, LLC	1						
First Wind Operations & Maintenance	1						
Long Island Power Authority	1						
Massachusetts Municipal Wholesale Electric Company	1	1			1		
New York Power Authority	1	1			1		
NextEra Energy Resources, LLC	1	1			1		
NRG Energy Inc.	1	1			1		
Nova Scotia Power Inc.	1	1					1
Ontario Power Generation Inc.	1	1			1		
PSEG Fossil LLC	1	1				1	
Talen Energy Supply, LLC	1	1				1	
TransCanada	1	1			1		
Vistra Energy Corp	1	1			1		
Wheelabrator Westchester LP	1	1				1	

		1. Determine Quorum			2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 5, Marketers, Brokers, Aggragators	**12**	**9**	**0**		**8**	**0**	**1**
Brookfield Power Corporation	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Consolidated Edison Energy/Development	1						
HQ Energy Marketing Inc.	1	1			1		
H.Q. Energy Services (U.S.) Inc.	1	1			1		
Long Island Power Authority	1	1			1		
Massachusetts Municipal Wholesale Electric Company	1	1			1		
Nalcor Energy	1						
New York Power Authority	1	1			1		
Nexus Energy Inc.	1	1					1
Shell Energy North America	1						
Utility Services Inc.	1	1			1		

		1. Determine Quorum			2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 6, State and Provincial Reg. and Govt. Au	**5**	**3**	**0**		**3**	**0**	**0**
Long Island Power Authority	1	1			1		
Maine Public Utilities Commission	1	1			1		
New Hampshire Public Utilities Commission	1						
New York Power Authority	1	1			1		
New York State Department of Public Service	1						

		1. Determine Quorum			2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 7, Sub Regional Rel. Councils, REs and Others	**25**	**16**	**0**		**14**	**0**	**2**
4g Technologies, LP	1						
Abloy Security, Inc.	1	1			1		
AESI Acumen Engineered Solutions Internaiontal Inc.	1	1			1		
Ascendant Energy Solutions, Inc.	1						
Casimir Systemics LLC	1	1			1		
Ciufo & Cooperberg Consulting Inc.	1	1			1		
DataCapable, Inc.	1						
David Kiguel	1	1			1		
ERLPhase Power Technologies	1	1			1		
GDS Associateds, Inc.	1	1			1		
Genieall	1						
International Business Machines Corporation	1						
Ironhouse Inc.	1						
McCoy Power Consultants, Inc.	1	1			1		
Network & Security Technologies, Inc.	1	1					1
New Power Technologies, Inc	1						
New York State Reliability Council, LLC	1	1			1		
Oxbow-Sherman Energy, LLC	1	1			1		
PLM, Inc.	1	1			1		
Preti, Flaherty, Beliveau, and Pachios, LLP.	1	1					1
Proven Compliance Solutions, Inc.	1	1			1		
SGC Engineering, LLC	1	1			1		
Sund Technologies, LLC	1						
TRC Solutions	1	1			1		
VIASYN, Inc.	1						

Determine Electronic Quorum

Sector	Sector Name	Total Registered	In Attendance	By Proxy	Total Represented	Sector % Attending
1	**Transmission Owners**	17	17	0	17	1.00
2	**Reliability Coordinators**	5	5	0	5	1.00
3	**TDUs, Dist. And LSE**	21	17	2	19	0.90
4	**Generator Owners**	20	16	0	16	0.80
5	**Marketers, Brokers, Aggragators**	12	9	0	9	0.75
6	**Customers- large and small**	5	3	0	3	0.60
7	**State and Provincial Reg. and Govt. Authorities**	25	16	0	16	0.64
		105	83	2	85	

Electronic Vote Quorum= at least 2/3 of the Total Registered

Quorum Present? **YES**

Determine if Motion or Item Passes

Sector	Sector Name	Total Registered	Sector % Attending	Affirmative # of Votes	Affirmative Fraction	Negative # of Votes	Negative Fraction	Abstain # of Votes	Votes Cast Total (-Abstentions)	Sector has Voted(1-Y, 0-N)
1	**Transmission Owners**	17	1.00	17	1.000	0	0.000	0	17	1
2	**Reliability Coordinators**	5	1.00	5	1.000	0	0.000	0	5	1
3	**TDUs, Dist. And LSE**	21	0.90	19	1.000	0	0.000	0	19	1
4	**Generator Owners**	20	0.80	10	0.714	4	0.286	2	14	1
5	**Marketers, Brokers, Aggragators**	12	0.75	8	1.000	0	0.000	1	8	1
6	**Customers- large and small**	5	0.60	3	1.000	0	0.000	0	3	1
7	**State and Provincial Reg. and Govt. Authorities**	25	0.64	14	1.000	0	0.000	2	14	1
	Totals	105		76	6.714	4	0.286	5	80	7

Sum of Affirmative/Number of Sectors that Voted MUST BE AT LEAST 2/3 to pass 0.959

Did MOTION PASS? PASS

NPCC, Inc.

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

Northeast Power Coordinating Council, Inc.
Directory Development and Revision Manual

&

Process for the Review and Approval of Criteria, Guidelines, and Procedures

August 2019
Redlined to Open Process Posting
Cost Effectiveness Revisions



Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/26/2011	Effective Date	New
1	12/5/2013	Revised	Revised Interpretation Approval Process
2	10/03/2014	Revised	Added NPCC CEAP Considerations
3	8/23/2018	Revised	Added Process for Review and Approval of Criteria, Guides, and procedures from Document A-01 to permit retirement of A-01
4	X/X/XXXX	Revised	Cost Effectiveness Assessment Procedure and Specify Identification of Incremental Reliability Benefit

I. CONTENTS

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II. EXECUTIVE SUMMARY

The Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. One of the ways NPCC carries out its mission is through the development of regionally specific criteria, and monitoring and enforcement of compliance with such criteria. NPCC Directories have been developed in order to provide a consistent and comprehensive set of reliability requirements for the Northeast, while consolidating related information for NPCC Criteria, Guidelines, Procedures as well as FERC and NERC approved Regional Standards into one document.

This document provides guidance to the NPCC Task Forces and NPCC Full Members when establishing a new or revised Directory, when retiring, or consolidating an existing Directory. This document also clarifies the roles and responsibilities of the NPCC Task Forces responsible for developing and maintaining Directory content.

The NPCC Regional Standards Committee (RSC), working with the lead Task Force for each Directory, has overall responsibility for managing the Directory project. Individual Directories are under the control of a lead NPCC Task Force which is responsible for coordinating review among all other Task Forces which have jurisdiction over either a portion of the criteria or one or more of the Appendices in the Directory.

NPCC also recognizes the industry concern surrounding the ongoing costs of maintaining the more stringent or more specific NPCC criteria contained within the NPCC Directories and the NPCC Board of Directors has expressed support for the appropriate balance between the incremental reliability benefit achieved by the criteria versus the cost to maintain or implement those criteria. Accordingly, an evaluation of the cost effectiveness of achieving the incremental reliability benefit has been incorporated into this Directory Development and Revision Manual and appears in Section VIII.

This document also contains the process for the review and approval of Criteria, Guideline, and Procedure documents that have not been incorporated into a Directory and remain as standalone documents outside of any Directory.

III. BACKGROUND

NPCC Reliability Directories have been developed consistent with the NPCC Bylaws which provide for the establishment of regionally specific reliability criteria, guidelines and procedures; within each Directory NPCC's reliability criteria has been reviewed and translated to ensure that the criteria is not inconsistent with the ERO standards as required by the NERC Rules of Procedure.

Each Directory also contains former Guideline – Type "B" and Procedure – Type "C" documents which have been renamed as Appendices and are functionally relevant to the document's Criteria. The Appendix supports the achievement of system performance related to the criteria and the consistent implementation, interpretation and monitoring of the criteria requirements.

Phase 1 of the Directory Project was initiated by the NPCC Reliability Coordinating Committee (RCC) in order to demonstrate consistency with NERC Standards and to effectively group documents together according to functional topics. During Phase 1 an initial translation of the existing criteria document was performed in addition to identifying and eliminating language within the criteria that duplicated existing NERC Reliability Standards.

Also during Phase 1, Functional Model language was introduced and the corresponding "B" Guidelines and "C" Procedures were incorporated into each Directory as Appendices. The resulting Directory created a single source reference for all entities while providing a method to demonstrate consistency with NERC Standards. All work from Phase 1 has been completed.

Phase 2 of the Directory Project was initiated in order to reformat the Criteria section of each document into specific and measurable NERC style requirements which will promote the NPCC Regional Criteria as more specific or more stringent within each Directory. Phase 2 will also facilitate the development of the NPCC Criteria Compliance Enforcement Program (CCEP) by providing the respective requirements of that program.

A mapping document has been provided on the Directory page of the NPCC Website and has been organized in a manner that provides guidance on where a Directory's content originated ("A"- Criteria, "B"- Guideline, or "C"- Procedure). The mapping document provides tracking of specific content language from documents that were translated or replaced by Directories and their Appendices.

Most of NPCC's "B" Guideline and "C" Procedure documents were transferred to Directories as Appendices in support of the relevant criteria. Those B and C documents that were not incorporated into a Directory remain as standalone documents

Further work on the individual Directories will emphasize the importance of identifying the specific incremental reliability benefit provided by the criteria beyond the NERC Standards and if any cost effective alternatives exist or were considered. This additional work will be done during the normal course of development or review by the Task Force responsible for the Directory.

III. APPLICABILITY OF NPCC CRITERIA

The requirements of an NPCC Directory apply only to those facilities defined as NPCC bulk power system elements as identified through the performance based methodology of NPCC Document A-10, "Classification of Bulk Power System Elements," the current list of which is maintained by the NPCC Task Force on System Studies and approved by the NPCC Reliability Coordinating Committee.

Requirements to abide by an NPCC Directory may also reside in NPCC Member tariff requirements, bilateral contracts and other agreements between facility owners and/or operators and their assigned Reliability Coordinator, Planning Coordinator, Transmission Operator, Balancing Authority and/or Transmission Owner as applicable

and may be enforceable through those external tariff requirements, bilateral contracts and other agreements.

IV. TASK FORCE ROLES AND RESPONSIBILITIES

With the development of the Directories it has been recognized that in certain cases more than one Task Force is responsible for the content of a Directory and coordination between Task Forces is necessary. In general, revisions and clarifications to a Directory shall be coordinated by the Lead Task Force of the document. Revisions to a Directory can be initiated in a fully bi-directional manner; that is either by the Lead Task Force responsible for the document or by another Task Force who is responsible for some portion (criteria or appendices) of the document.

This process will allow each Directory to remain under the control of the respective Lead Task Force which has the necessary expertise to keep each document current and accurate while also providing a means to coordinate component review of those segments of the Directory that may be under the control of another Task Force.

The Lead Task Force can initiate a full revi ew ~~sion~~ of the Directory in accordance with the NPCC Reliability Assessment Program (NRAP) date of approval or if a need to revise the criteria section of the document has been identified. ~~A link to the NRAP documents is provided in the References section of this manual.~~

The Lead Task Force will also notify other Task Forces under whose jurisdiction either a portion of the criteria or Appendices exists in order to coordinate the total document review and revision. Similarly, a Task Force which is not the Lead Task Force of the Directory, but is responsible for some portion of the document, shall coordinate a necessary revision to their section of the document through the Lead Task Force of the Directory.

The Lead Task Force will also consider the cost effectiveness of the proposed criteria within the Directory during each periodic review of the document or for any proposed revisions to the criteria.

Cost Effectiveness Analysis (CEA) will be conducted as outlined in Section VIII and will utilize survey questions developed by the Task Force to accompany the open process comment period(s). These questions will be designed to solicit Member comment on whether the Criteria represents an incremental benefit to reliability and whether there are any cost effective alternatives to achieving a similar or greater level of reliability. As noted in Section VIII, the Lead Task Force may waive the cost effectiveness portion of the review or conduct it any time during the development process.

In all cases, the Lead Task Force will document its cost effectiveness decisions and activities. The Lead Task Force may choose to waive the cost effective analysis portion of the development process if it is deemed to be of no added value (e.g. no change to established beneficial criteria or how to achieve the reliability objective). In this case, a letter from the Task Force Chair which indicates ~~ing~~ the desire of the Task Force ~~is~~ to

waive the CEA will be sent to the RCC and RSC to be stored with the developmental record and will be subject to RCC approval.

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE

1. NEW DIRECTORY

Any NPCC Full Member may request the development of a new Directory. The request shall be made to the NPCC Manager of Reliability Criteria and shall contain the background and justification for the development of the new Directory including a cost effectiveness assessment if available.

The NPCC Manager of Reliability Criteria shall forward the request for the development of a new Directory, to the appropriate Task Force (TF) and copy the Regional Standards Committee (RSC) and the Reliability Coordinating Committee (RCC). The Lead Task Force responsible for developing the new Directory shall review the request and all information submitted, including any cost effectiveness documentation and determine if the development activity is warranted. If the TF accepts the request, it will notify the RCC of its intent to develop a new Directory and conduct a Cost Effectiveness Analysis (CEA) in accordance with Section VIII of the Directory Manual to accompany the initial posting of the draft Directory.

Upon development of the new draft Directory the Lead Task Force shall post it to the NPCC Open Process for a 45 day comment period. The initial posting will include the cost effective survey questions as contained in Section VIII.

At the conclusion of the 45-day Open Process period, the Lead Task Force will consider comments received, develop responses to the comments and revise the Directory if necessary. The Lead Task Force shall also evaluate and document the results of the cost effectiveness survey questions.

The Lead Task Force will present the draft Directory along with the results of the cost effective analysis to the RCC.

The RCC will review the TF recommendation and conclude whether the new Directory should move forward for Full Member consideration based on its incremental reliability benefit and cost effectiveness.

If the RCC concludes that the development of a new Directory is not cost effective, the RCC will notify the Manager of Reliability Criteria for notification to the RSC, the Lead Task Force and the NPCC Full Member that submitted the request to develop a new Directory.

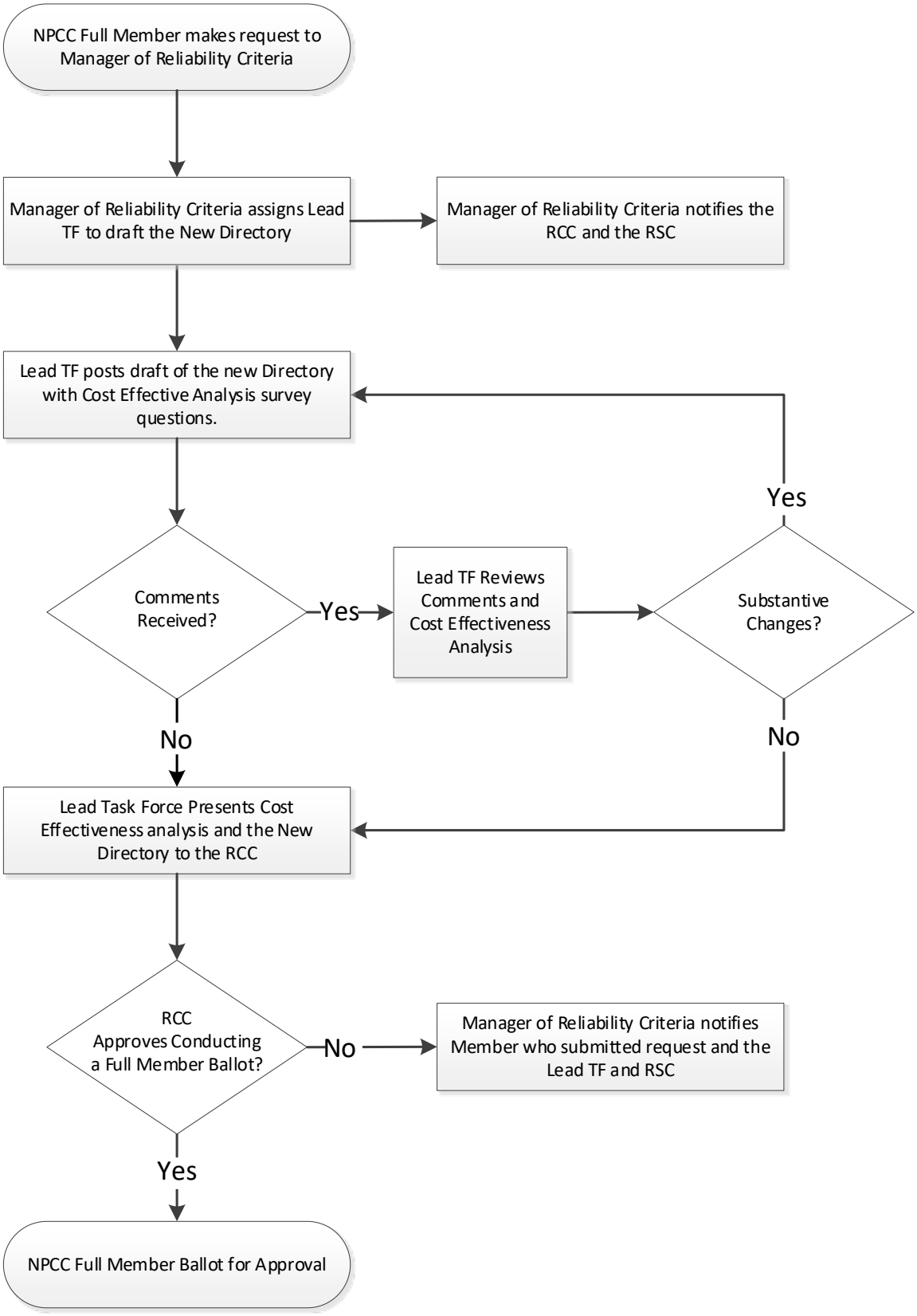
After consideration of cost effectiveness and reliability benefit if the RCC concurs ~~approves~~ that the ~~the~~ draft Directory has been developed in accordance with relevant procedures the RCC will approve conducting a Full Member ballot on the content of the new Directory in accordance with NPCC By Laws.~~it is then submitted for final approval~~

~~by the NPCC Full Member Representatives along with the RCC recommendation of approval.~~[1]

The process for establishing a new Directory is represented below in Figure 1:

[1] Approval of a new or revised Directory requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

Figure 1: New Directory



2. DIRECTORY REVISIONS

a. REVISIONS TO THE CRITERIA SECTION OF A DIRECTORY

The Lead Task Force can initiate a full revision of the Directory in accordance with the NPCC Reliability Assessment Program (NRAP) date of approval or some need to revise the criteria section of the document as determined by a Full Member, the Lead Task Force itself or due to revision of a NERC Standard.

A request to revise the criteria section of an NPCC Directory shall be submitted to the Lead Task Force responsible for the document. The Lead Task Force shall notify each affected NPCC Task Force which has jurisdiction over either a portion of the criteria or one or more of the appendices within the Directory that a request to revise the criteria in the document has been received.

The Lead Task Force shall review the request to revise the criteria and shall also consider conforming changes to appendices as a result of the criteria revision if necessary.

The Lead Task Force will also consider the cost effectiveness of the criteria within the Directory during each periodic review of the document or for any proposed revisions to the criteria.

The cost effectiveness of the criteria will consist of CEA survey questions developed by the Task Force and which are designed to solicit Member comment on the relative cost of different approaches to achieving the level of reliability provided by the criteria. Emphasis will be placed on identification of the incremental reliability benefit of the criteria beyond that which may be achieved by any associated NERC Standards.

These survey questions will accompany the Open Process 45 day posting of the Directory in order to promote transparency.

Section VIII provides guidance for the CEA and Open Process posting. If the Lead Task Force determines that there is no benefit to conducting the CEA activity then this decision shall be documented and notification provided to the RCC and RSC along with the reasons for the decision to waive this portion of the process.

The NPCC Manager of Reliability Criteria shall post the Directory containing the revised criteria to the NPCC Open Process review for 45 days, along with the survey questions developed to assess the cost effectiveness of the criteria. The survey responses will be documented and archived as part of the record of the Task Force review.

At the conclusion of the 45-day Open Process, the Lead Task Force will discuss the comments submitted and post responses to comments on the NPCC Open Process portal. If the responses to the comments received on the criteria revision result in substantive changes to the document, then the revised Directory criteria shall be reposted to the Open Process for an additional 45 day posting period.

Alternatively, if there are no substantive changes which would require additional postings, the Directory is presented to the Reliability Coordinating Council (RCC) for approval along with any information regarding incremental reliability benefit and cost effectiveness.

If the RCC concludes that the proposed revision(s) to the criteria section of a Directory is (are) not cost effective, the RCC will notify the Manager of Reliability Criteria for notification to the RSC, the Lead Task Force and, if applicable, the NPCC Full Member that submitted the request to revise the Directory.

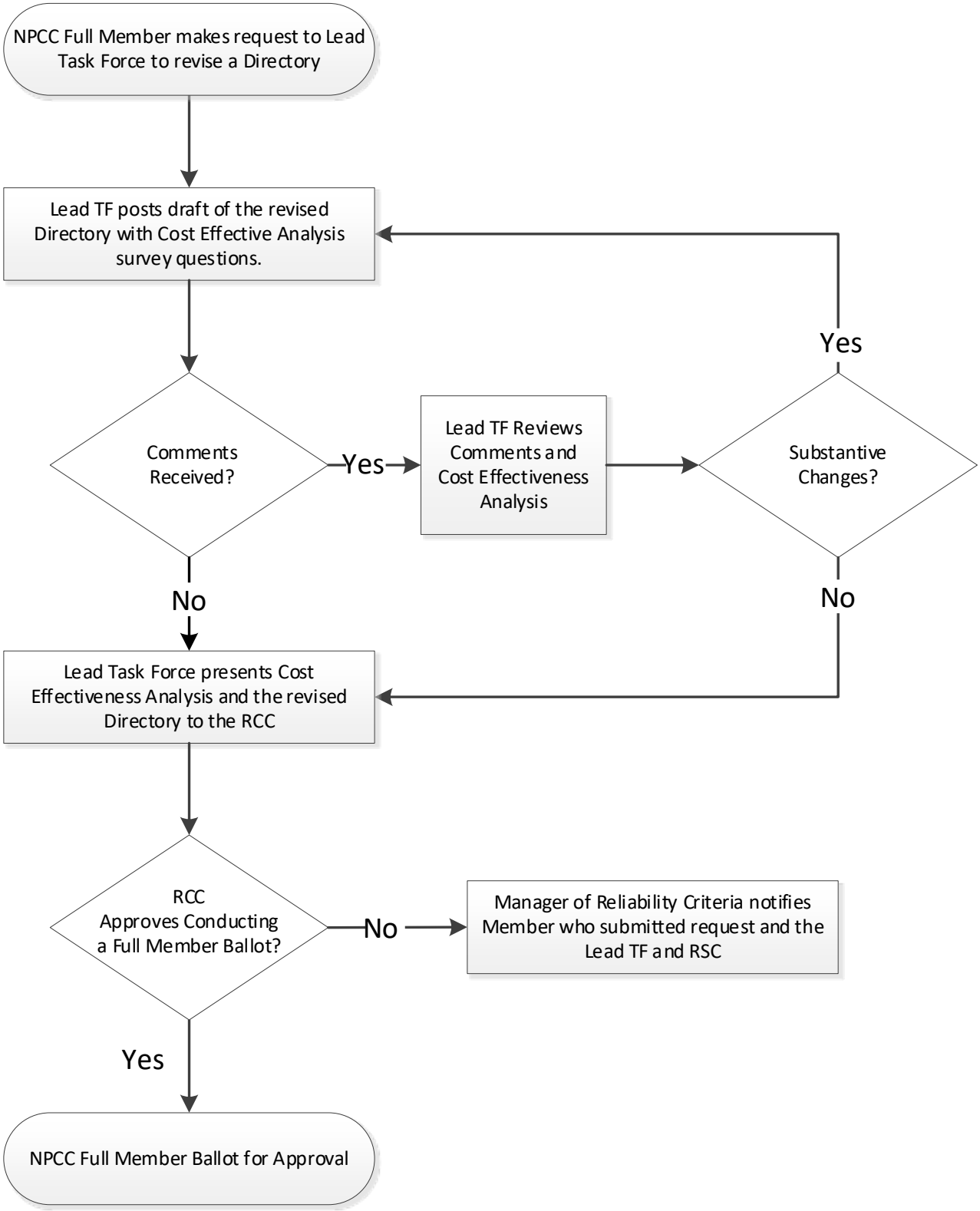
After consideration of cost effectiveness and reliability benefit if the RCC concurs that the revised Directory has been developed in accordance with relevant procedures the RCC will approve conducting a Full Member ballot on the content of the revised Directory in accordance with NPCC By Laws.

~~Upon RCC approval, the document is submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.~~

Approval of the revised Directory criteria requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

The process for revisions to the criteria in an existing Directory is represented below in Figure 2:

Figure 2: Revisions to Criteria



b. REVISIONS TO THE APPENDIX SECTION OF A DIRECTORY

Any NPCC Full Member may request an Appendix within a Directory to be revised, added or retired. Revisions, additions or retirements of Appendices shall only require Task Force approval.

A request to revise, add or retire an Appendix of a NPCC Directory shall be submitted to the Task Force responsible for the Appendix. The Task Force responsible for the Appendix shall notify the Lead Task Force of the Directory that a request to revise, add or retire an appendix within the document has been received.

The Lead Task Force of the Directory shall be responsible for notifying all Task Forces which have jurisdiction over either the criteria or one or more of the other Appendices within the Directory that a request to revise, add or retire an appendix has been received. The Lead Task Force will also determine whether to waive or conduct cost effective activities associated with the proposed revisions to the Appendix and notify the RCC and RSC of such determination.

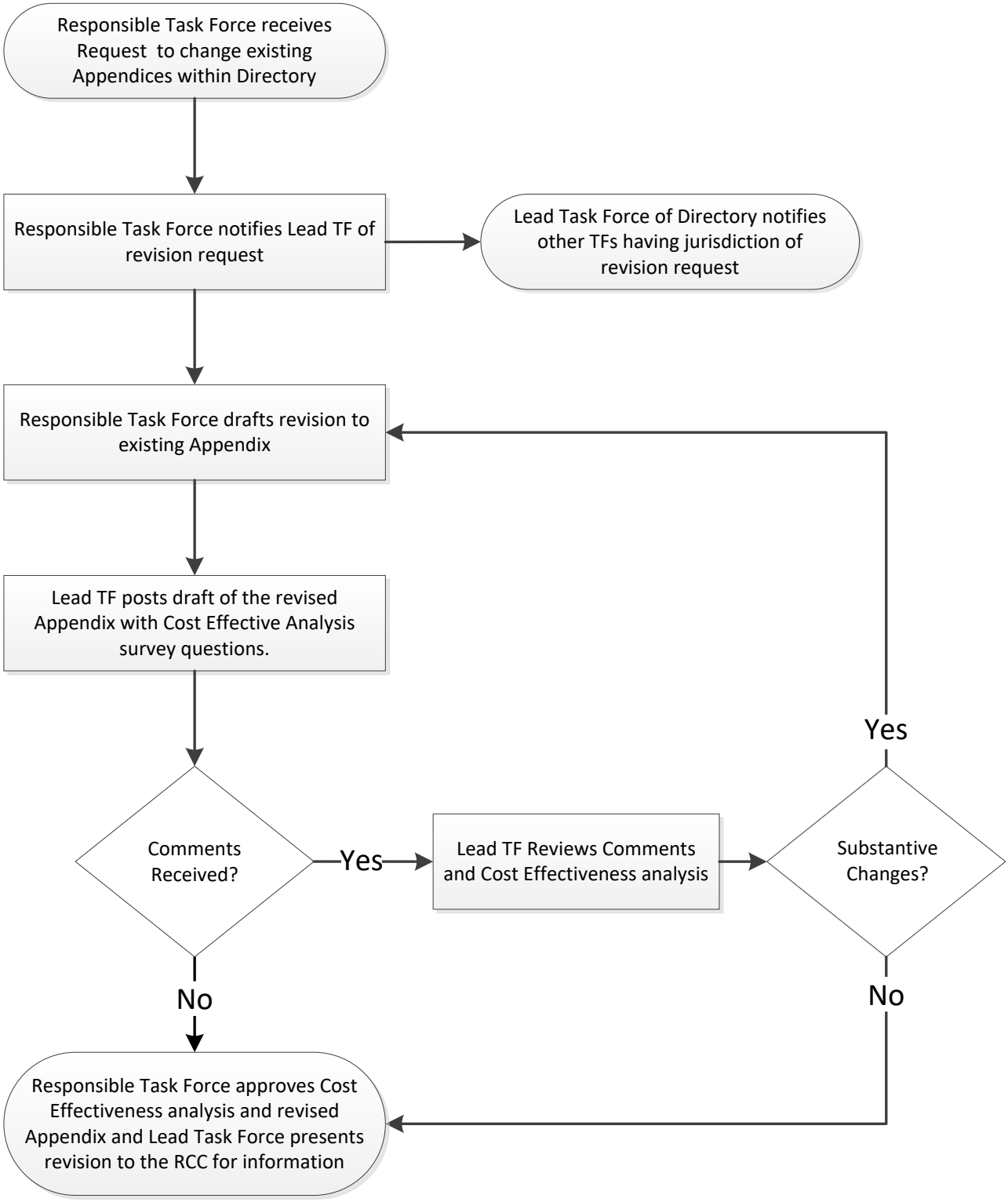
After the Task Force responsible for the revised Appendix request reviews the subject Appendix, they will forward the Directory containing the draft revised Appendix to the Lead Task Force of the Directory. The Lead Task Force shall be responsible for posting the Directory (in its entirety) which contains the new, revised, or retired Appendix to the NPCC Open Process review for 45 days and will also conduct the cost effectiveness activities as described in Section VIII if necessary. The Lead Task Force will limit the comments solicited to only the subject Appendix.

At the conclusion of the 45-day Open Process, the Lead Task Force will forward the comments submitted on the Appendix to the Task Force responsible for the new, revised, or retired Appendix. If the responses to the comments received on the new, revised, or retired Appendix result in substantive changes to the Appendix, then the Directory containing the new, revised, or retired Appendix shall be reposted to the Open Process for a successive 45-day review period by the Lead Task Force of the entire Directory. Alternatively, if there are no substantive changes which would require additional postings, the new, revised or retired Appendix shall be voted on by the Task Force responsible for the Appendix.

The lead Task Force for the Directory containing the new, revised or retired Appendix shall distribute the Directory containing the revised or retired Appendix to the RCC for informational purposes.

The process for revisions to the Appendices within an existing Directory is represented below in Figure 3:

Figure 3: Revisions to Appendices



c. REVISIONS TO THE NPCC GLOSSARY OF TERMS

The NPCC Glossary of Terms contains the definitions of all terms found within the NPCC Directories, Criteria, Guidelines, and Procedures ~~and which are not already defined in the NERC Glossary of Terms~~ or are regionally specific. The Glossary of Terms is intended to be a repository of all NPCC defined terms and contains the Full Member approved definition of that term as developed by the Task Force responsible for the Directory in which the term resides.

The Glossary is organized into two sections, one containing all defined terms within the Directories (including Appendices) which support the NPCC Criteria and another section for definitions found within remaining B and C documents.

The process of establishing or revising a NPCC defined term shall be considered a revision to the Directory in which the term resides in order to capture the context of its use within the document. Accordingly, the entire Glossary is not subject to the Open Process for a revision to an individual definition.

The development and review of a new definition or a revision to an existing NPCC specific definition contained within the Glossary will be coordinated by the Lead Task Force for the Directory in which the defined term resides.

Any NPCC Full Member may request that a Glossary term be revised or added to the NPCC Glossary of Terms by forwarding a request to the Lead Task Force for the Directory in which the defined term to be revised resides or will reside. When the subject term resides in multiple Directories, the requestor shall forward the request to each of the Task Forces for the Directories in which the defined term resides and the individual Task Forces shall coordinate their review of the request, by assigning one of the Task Forces as the Lead Task Force for the review.

In general, it is not anticipated that the development of a new or revised term in the Glossary will result in significant cost implications. However, ~~the NPCC Manager of Reliability Criteria may request~~ the Lead Task Force may ~~to~~ utilize the cost effectiveness analysis as described in Section VIII to identify cost impact and reliability benefit of the proposed or revised Glossary term.

The RCC will review the results of the cost effectiveness analysis conducted for the proposed or revised Glossary term with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the process of establishing a new or revised Glossary term.

In accordance with Section VIII, if the RCC concludes that the development of a new or revised Glossary term is not cost effective, the RCC will forward the determination to the Manager of Reliability Criteria for notification to the Lead Task Force and NPCC Full Member.

After the Lead Task Force, in which the defined term resides, has completed its review, they will post the subject Directory containing the new or revised term to the NPCC Open Process for 45 days. When the new or revised term appears in multiple Directories, the designated Lead Task Force for the review shall include in the posting

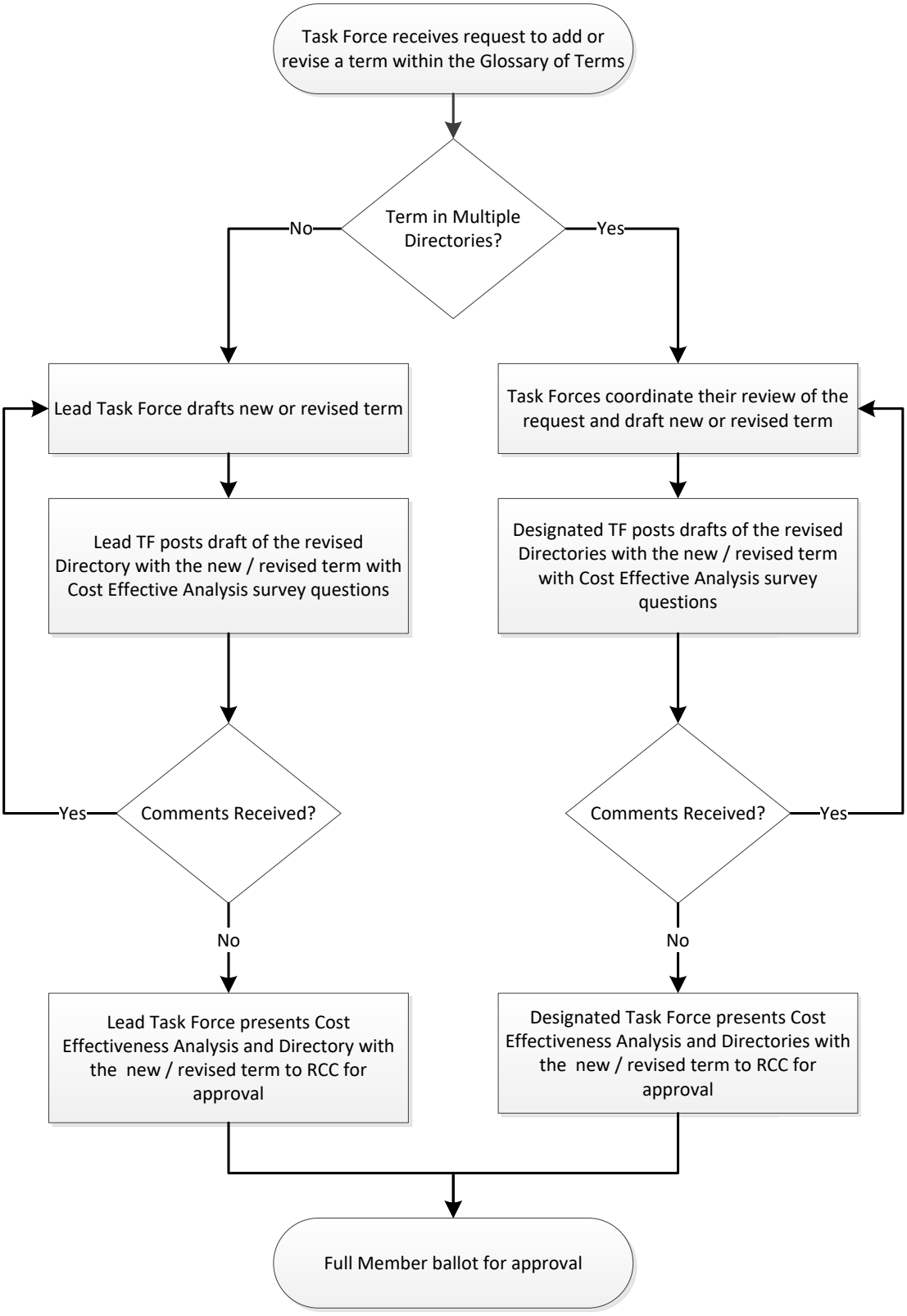
notice a comprehensive list of references to all occurrences of the defined term in other NPCC Directories, including each Directory in which the term resides.

At the conclusion of the 45-day Open Process, if responses to comments received on the new or revised term result in further substantive change to the term, then the Directory containing the new or revised term shall be reposted to the Open Process for a successive 45 day posting period by the Lead Task Force for the subject Directory. Alternatively, if no substantive changes to the term are developed which would require an additional posting, then the Directory containing the new or revised term will be presented to the Reliability Coordinating Council (RCC) by the Lead Task Force for approval.

Upon RCC approval, the Directory containing the new or revised term will be balloted by the Full Members. Upon Full Member approval of the new or revised term the Glossary will be updated by the Lead Task Force of the document in which the term resides.

The process for revisions to the Glossary of Terms is represented below in Figure 4:

Figure 4: Revisions to the NPCC Glossary of Terms



d. WITHDRAWAL OF REVISION REQUESTS

Any NPCC Full Member which has initiated a request to develop a new Directory, revise an existing Directory or revise an NPCC Glossary Term may withdraw the request at any time prior to Full Member approval of the revised Directory or NPCC Glossary Term by notifying the NPCC Manager of Reliability Criteria. The NPCC Manager of Reliability Criteria will then notify the Lead Task Force, RSC and RCC.

3. DIRECTORY RETIREMENT

Upon identification of the need to retire an existing Directory, the Lead Task Force responsible for the Directory shall notify the NPCC Manager of Reliability Criteria of its proposal to retire a Directory.

The proposal shall include the rationale for the retirement and a statement regarding the impact of retirement on the reliability of the Bulk Power System. The NPCC Manager of Reliability Criteria shall post the proposal, along with supporting documentation to the NPCC Open Process for 45 days.

At the conclusion of the 45-day Open Process, the Lead Task Force will review the comments submitted and post responses on the NPCC Open Process portal. The NPCC Manager of Reliability Criteria shall present the proposal to retire the Directory to the Reliability Coordinating Council (RCC) for approval.

Upon RCC approval the proposal to retire the Directory will be submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation to retire the document.

4. MAINTENANCE OF LINKS AND ERRATA

The maintenance of Links and the correction of errors found in a Directory or its Appendices shall be the responsibility of NPCC Standards staff. An error may be classified as Errata provided its correction does not change the scope or intent of the Directory and has no impact on the end user of the Directory.

Errata and Link revisions are updated as needed and require only the Lead Task Force approval prior to publishing and notifications to the applicable regulatory jurisdictions if required.

NPCC staff will also maintain a record of the change on the Directory Revision History page within the document.

VI. DIRECTORY CLARIFICATION PROCESS

a. REQUEST FOR CRITERIA CLARIFICATION

Any NPCC Full Member may request a clarification of the criteria within a Directory. The NPCC Full Member seeking the clarification shall submit a ***Request for Criteria Clarification*** form [2] to the NPCC Manager of Reliability Criteria explaining the clarification required and the specific circumstances surrounding the request. The NPCC Manager of Reliability Criteria shall review the request and work with the originator to make certain that the request is clearly written, seeks clarity regarding the intent or purpose of the criteria and is not a question on a compliance aspect of the criteria.

The Manager of Reliability Criteria will forward an approved *Request for Criteria Clarification* to the NPCC Task Force designated as the Lead Task Force for the subject Directory. The Lead Task Force shall notify each NPCC Task Force which has jurisdiction over either another portion of the criteria and /or one or more of the appendices within the subject Directory, that a ***Request for Criteria Clarification*** has been received. The Lead Task Force shall also forward the request to the affected Task Force.

The Lead Task Force for the Directory or the Task Force having jurisdiction shall review the request among its Members and provide a response to the NPCC Manager of Reliability Criteria within 60 calendar days. The Manager of Reliability Criteria shall post the ***Request for Criteria Clarification***, along with the responses provided by the Lead Task Force to the NPCC Open Process for 45 days.

The Lead Task Force will consider all comments received on the posted clarification and if necessary revise the clarification based on these comments. If the Lead Task Force revises the clarification substantively on the basis of comments received the clarification shall be reposted to the NPCC Open Process for a successive 45 day posting period.

The Manager of Reliability Criteria will coordinate a response to all commenters on behalf of the Lead Task Force. The Lead Task Force response to a Directory clarification request shall provide the requested explanation without expanding on the criteria and should be sufficiently concise to eliminate any ambiguity.

The NPCC Manager of Reliability Criteria shall review the clarification provided by the Lead Task Force or the Task Force having jurisdiction to ensure that it is clear and provides the requested explanation without expanding on the criteria.

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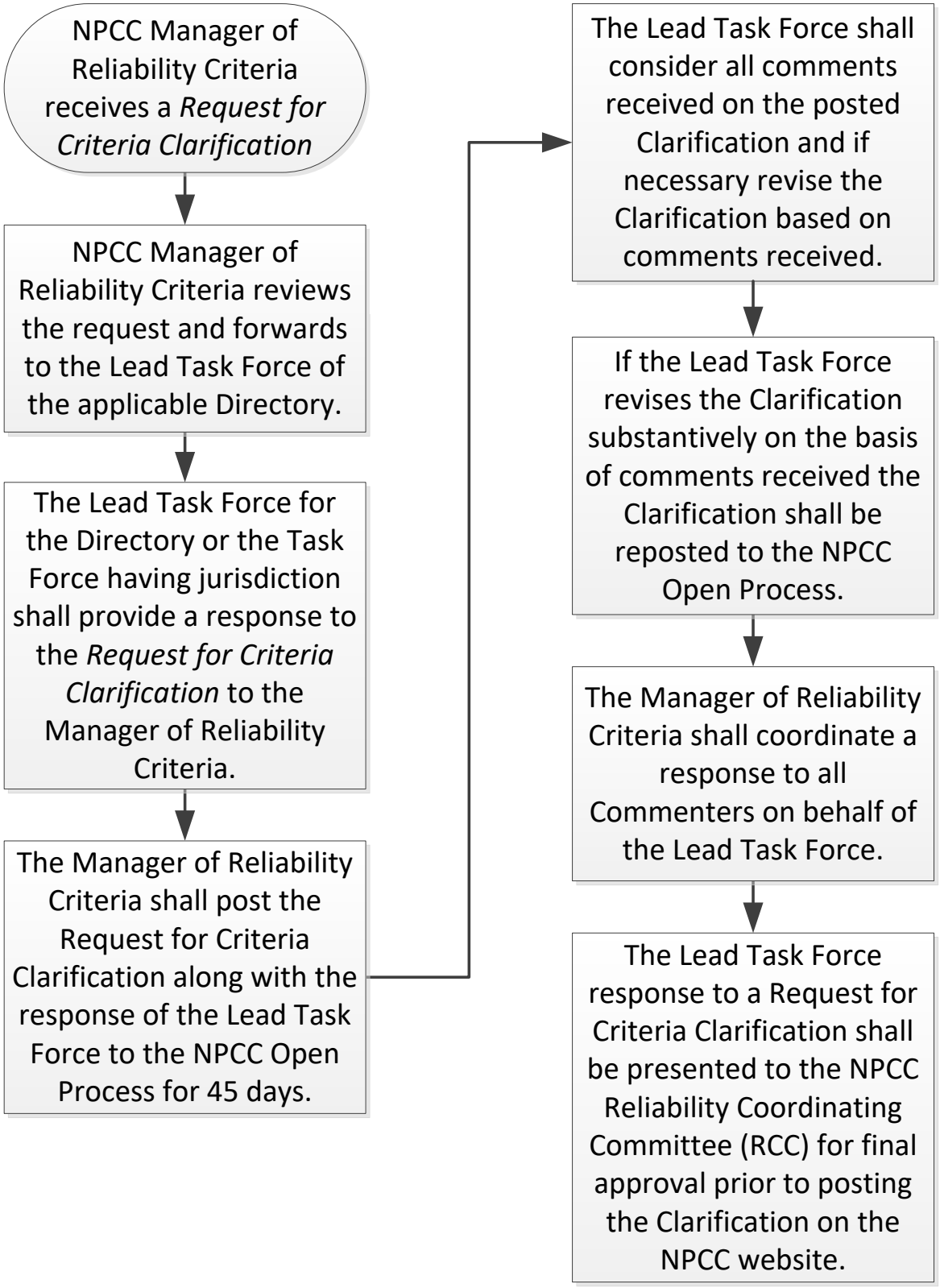
[2] The Request for Clarification Form is included in Appendix B of this document.

The Lead Task Force response to a ***Request for Criteria Clarification*** shall be presented to the NPCC Reliability Coordinating Committee (RCC) for final approval prior to posting the clarification to the NPCC website.

The detailed results of the ***Request for Criteria Clarification*** shall be retained by the Lead Task Force and the NPCC Standards Staff along with a recommendation on whether the language within the document should be revised in order to provide additional clarity.

The process for a Criteria Clarification Request is represented below in Figure 5:

Figure 5: Request for Criteria Clarification



b. APPEALS

Any NPCC Full Member that has submitted a *Request for Clarification* may appeal the rendered Task Force response.

The appellant shall submit a written complaint to the NPCC Manager of Reliability Criteria describing the substantive or procedural action or inaction associated with the Clarification Request process.

The appellant shall also describe in the complaint the actual or potential adverse impact to the appellant.

Assisted by any necessary NPCC Standards Staff and Lead Task Force resources, the NPCC Manager of Reliability Criteria shall prepare a written response addressed to the appellant as soon as practical, but not more than forty-five (45) calendar days after receipt of the complaint.

VII. DIRECTORY FORMAT AND VERSION CONTROL

Each Directory will be formatted in accordance with the Directory Template in Appendix A of this document.

The Task Force Revision Review Record on the cover page of each Directory shall contain the date of the most recent version of the Directory as approved by the Full Members of NPCC.

The Revision History record on page 2 of each Directory shall contain a record of all revisions to the document, including maintenance of errata and links.

VIII. NPCC PROCEDURE FOR COST EFFECTIVE ANALYSIS (CEA) OF NEW AND REVISED CRITERIA IN DIRECTORIES

1. Upon receipt of a request to review or revise the criteria in an existing Directory, by a NPCC Full Member, or a request to develop a new Directory, the Task Force having jurisdiction (Lead Task Force) will determine if the activity warrants conducting a cost effectiveness analysis.

2. The Lead Task Force will document these activities as part of the record of development and notify the RCC and RSC if a waiver of the CEA will be exercised.~~of intent to conduct cost effectiveness analysis or exercise a waiver.~~ The RCC may accept the Lead Task Force determination not to proceed with a CEA or request that a CEA be completed.

3. If the Task Force later determines that conducting a cost effectiveness analysis is warranted at any time during the development process of the new or revised Directory, the Task Force will notify the NPCC Manager of Reliability Criteria.

4. NPCC will coordinate the necessary cost effective analysis as directed by the Task Force. These activities will focus on identification of the incremental reliability

benefit of the Criteria and the cost effectiveness associated with that benefit. The Lead Task Force shall use the subject matter expertise of its Members as well as other TFs, as may be applicable, along with the Open Process 45 day posting(s) for comment to gather this information (See below for sample questions).

- Does the proposed Criteria provide an increased level of reliability? If not, why not (probabilistic data, such as the information taken from the Reliability Issues Steering Committee report(s) regarding probable occurrence of a risk may be used to help make a determination)
- Is there a more cost effective solution to achieving the same or greater level of reliability if a different approach is taken? If so what is that solution? What are its costs relative to the original Criteria and associated processes?
- How long would it take your organization to implement full compliance to the Criteria as written? What would affect the implementation (i.e. outage scheduling, availability of materials, human resources, etc.)?

5. The Task Force shall use the information obtained, to make a determination if the revised or new Criteria is of sufficient reliability benefit to pursue further development activities by NPCC or if other cost effective approaches to achieve the reliability objective of the Criteria should be pursued. (e.g. development of a whitepaper, guideline document, etc.)

IX. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES

Introduction

The Process for Review and Approval of Criteria, Guidelines, and Procedures was formerly outlined in NPCC Document A-01 *Criteria for Review and Approval of Documents.* The Directory Project has consolidated most NPCC Criteria-Type "A" documents, Guideline-Type "B" documents, and Procedure-Type "C" documents into the Directories.

This section is intended to outline the review and approval procedures, (the NPCC Open Process), to be followed for all remaining NPCC Criteria-Type "A" documents, Guideline-Type "B" documents, and Procedure-Type "C" documents.

Document, Criteria - Type "A"

General Description

Type "A" documents, with approval by the NPCC Full Member Representatives; describe the minimum criteria for Member Systems of NPCC functioning as part of the coordinated interconnected network.

Review and Approval

Type "A" documents are prepared and revised by the designated lead Task Force on a periodicity to be determined by the lead Task Force or initiated at the request of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Notification is also given to neighboring Regions whose reliability might be impacted by NPCC's Criteria. Their review of the proposed Criteria will be encouraged and comments will be considered for inclusion. The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required, which would require additional posting(s), the draft Type "A" document is presented by the lead Task Force to the Reliability Coordinating Committee (RCC) for its approval.

In its review, the RCC will determine if the proposed or revised Criteria are neither inconsistent with nor less stringent than NERC industry-wide reliability standards and are not intended to result in any undue competitive advantage or disadvantage to any party or parties. The NPCC recognizes that Member systems or local conditions may require criteria which are more stringent than those defined by NPCC Criteria.

Should the RCC determine that the document cannot be approved, the RCC will return the document to the lead Task Force.

Following the RCC's approval, the document is submitted to the NPCC Full Member Representatives for ballot, with a recommendation for its adoption. Approval of NPCC Criteria requires a 2/3rd affirmative majority of the weighted sector votes.

For modified Type "A" documents, once approval has been obtained from the Member Representatives, the document is officially adopted with an effective date or implementation plan, as noted on the document itself with the following statement:

"Adopted by the Members of the Northeast Power Coordinating Council Inc., on (mm, dd, yyyy) based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated January 1, 2012 as amended to date."

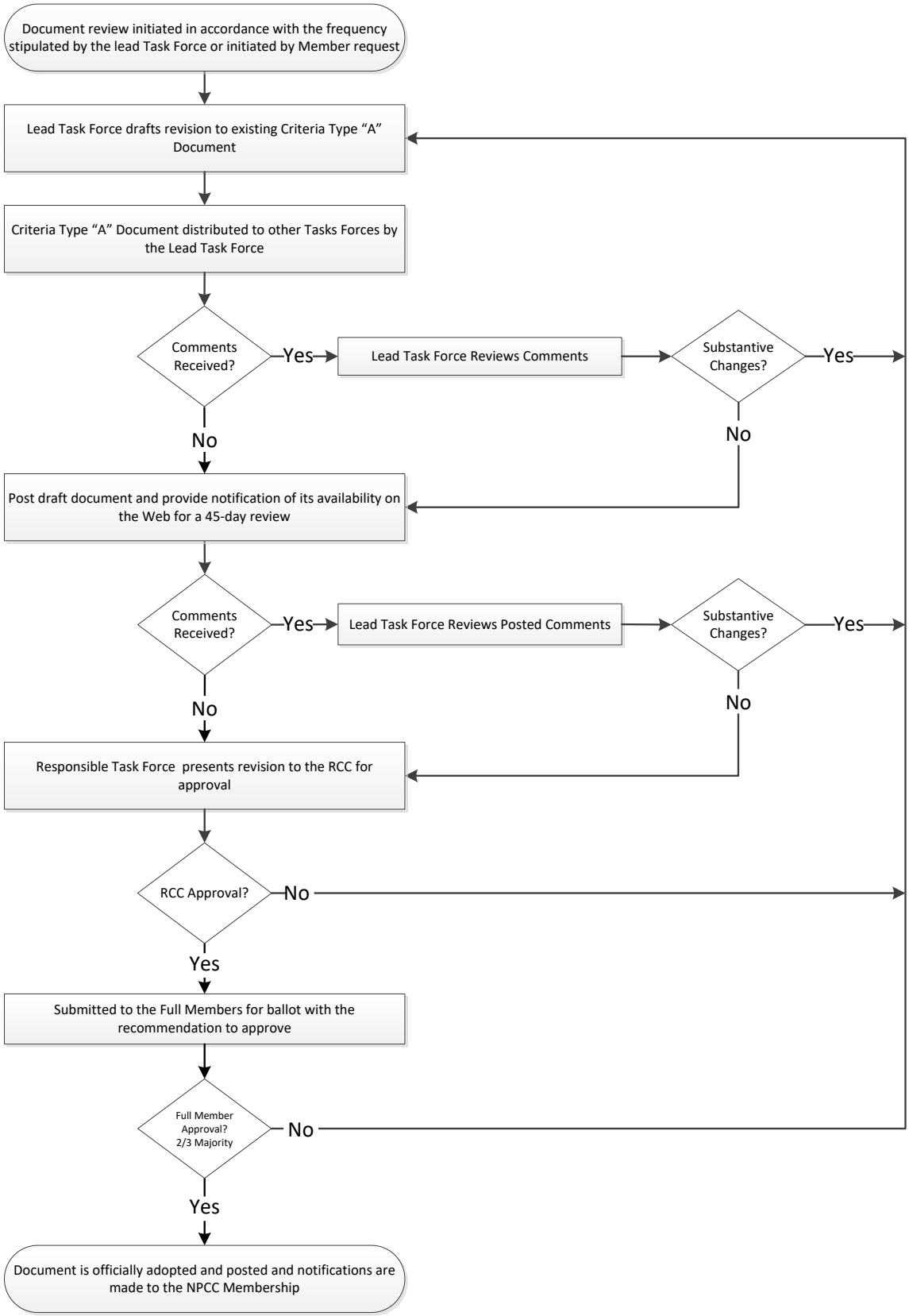
The approved and adopted Type “A” document will then be posted, along with necessary additional documentation, if needed, such as an implementation plan or schedule for achieving full compliance with the requirements outlined in the document. This will be posted on the NPCC web site and distributed to the membership via a documented and maintained distribution list.

Members may request the lead Task Force, at any time, to review and revise the Criteria, or portions thereof, and have the right to enter into the NPCC “Appeals and Dispute Resolution Process” for non-compliance issues.

Retiring a Type “A” document requires following the same steps as the revision process.

The process for revisions to the criteria in an existing Type "A" document is represented below in Figure 6:

Figure 6: Revisions to Document, Criteria - Type "A"



Documents: Guideline - Type "B" and Procedure-Type “C”

General Description

Type "B" documents are guideline documents.

Type "C" documents are procedures which provide for consistent implementation, interpretation and monitoring of conformance with the general criteria, guides and reporting requirements.

Review and Approval

Any NPCC Full Member may request a Guideline-Type “B” or a Procedure-Type “C” document be revised or retired. Revisions or retirements of Guideline-Type “B” or Procedure-Type “C” documents shall only require Task Force approval.

A request to revise or retire a Guideline-Type “B” or a Procedure-Type “C” document shall be submitted to the Task Force responsible for the document.

The Task Force shall be responsible for posting the revised or retired document to the NPCC Open Process review for 45 days.

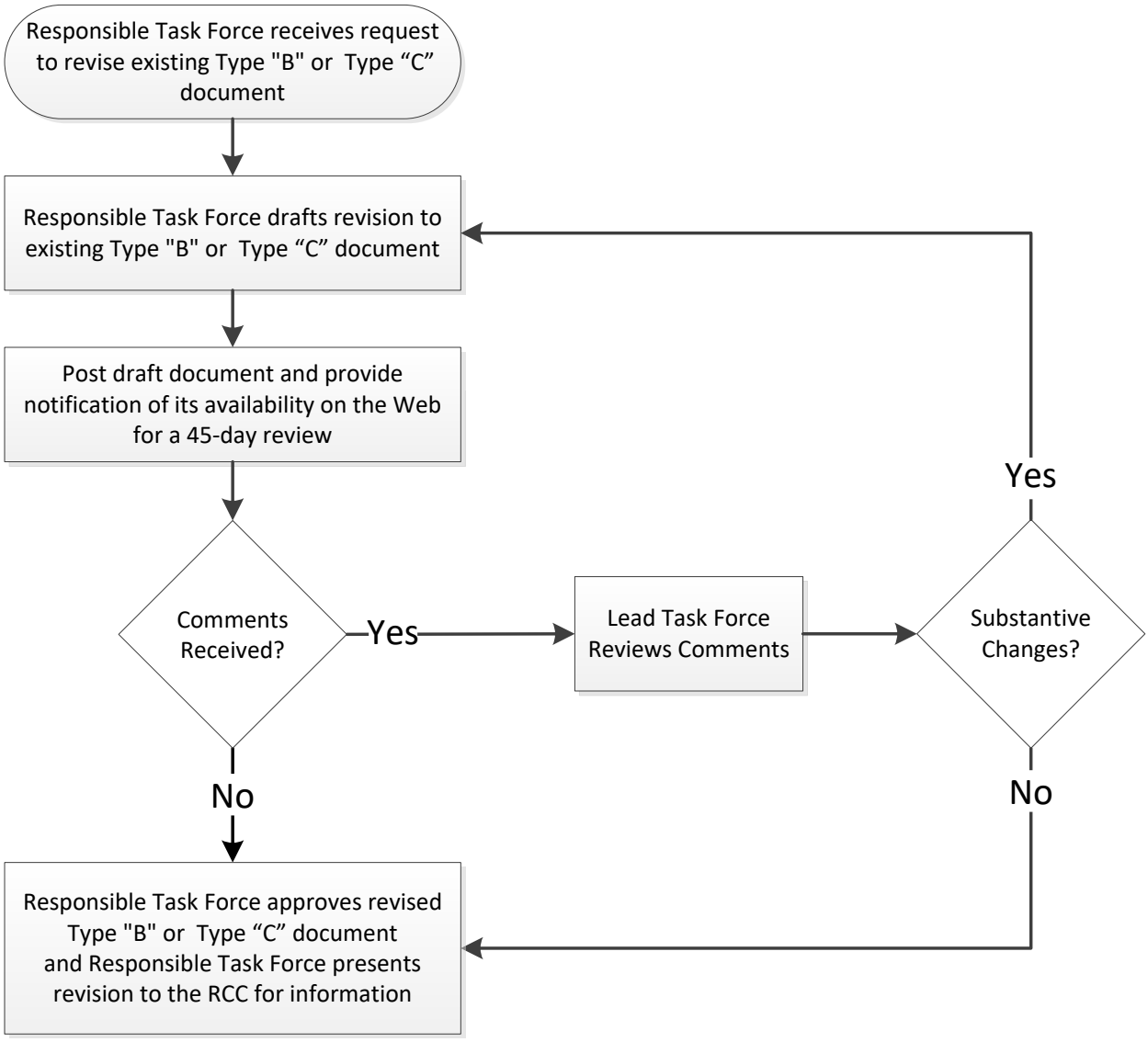
The revised B or C document (or the proposal to retire a B or C document) shall be posted to the NPCC Open Process for a 45-day posting.

At the conclusion of the Open Process, the Task Force responsible for the B or C document shall consider all comments received and incorporate comments as appropriate. If the comments received on the revised or retired document result in substantive changes to the document, then the document shall be reposted to the Open Process for a successive 45-day review period by the Task Force responsible for the document. Alternatively, if there are no substantive changes which would require additional postings, the revised or retired document shall be voted on by the Task Force responsible for the document.

The Task Force responsible for the document shall distribute the document to the Reliability Coordinating committee for informational purposes.

The process for revisions to an existing Type "B" and “C” document is represented below in Figure 7:

Figure 7: Revisions to Guideline - Type "B" and Procedure-Type “C” Documents



X. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL & PROCESS FOR THE REVIEW AND APPROVAL OF CRITERIA, GUIDELINES, AND PROCEDURES

The NPCC Directory Development and Revision Manual & Process for the Review and Approval of Criteria, Guidelines, and Procedures will be reviewed at least once every five (5) years or more frequently if required.

A notification of a pending RSC review and re-approval of the Manual shall be posted on the NPCC website. All revisions to this Manual shall be posted to the NPCC Open Process Review for 45 days.

The Regional Standards Committee (RSC) shall respond to all comments received and shall have final approval over the revised document.

APPENDIX A - DIRECTORY FORMAT TEMPLATE



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

NPCC
Regional Reliability Reference Directory # XX

Task Force XXXXX Revision Review Record:
XX/XX, 20XX

Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0		**Effective Date**	**New**

Format for NPCC Directories (Phase 2)

Effective Dates (Denotes date of adoption by the Membership)

Revision History (Depicts revision history and tracks key changes)

Table of Content (Self-explanatory)

A. Introduction

Title: Self-explanatory

Directory #: Self-explanatory

Objective: State the reliability objective that this Directory intended to meet (i.e., achieving specific performance target/outcome, mitigating particular risks, establishing the minimum capability level, etc.)

Effective Date: Identify which parts of the Directory become effective on which dates.

Background: Provide information related to this creation or revision of this Directory, e.g., which "A", "B" or "C" documents are mapped into this Directory; the general basis of the Directory, etc.

Applicability: Identify the entities that are assigned reliability requirements and/or which facilities need to conform to the stipulated criteria.

B. NERC ERO Reliability Standard Requirements

A list of the NERC standards associated with this Directory.

C. NPCC Regional Reliability Standard Requirements

A list of NPCC Regional Standards associated with this Directory.

D. NPCC Full Member, More Stringent Requirements, Criteria and Measures

Requirements

List the requirements and criteria that the applicable entities or facilities must comply with.

E. Compliance

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

Measures and corresponding Levels of Non-Compliance for these requirements are contained within the compliance template associated with this Directory.

Prepared by:	Task Force XX (Lead Task Force for the Directory)
Review and Approval:	Revision to any portion of this Directory will in accordance with the NPCC Directory Development and Revision Manual and will be posted by the Lead Task Force in the NPCC Open Process for a 45-day review and comment period. Upon satisfactorily addressing all of the comments in this forum, the Directory will be sent to the RCC for its approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as links, glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

APPENDIX B – NPCC REQUEST FOR CLARIFICATION



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

NPCC Request for Criteria Clarification

Note: An Interpretation cannot be used to revise a Directory.

Request for Criteria Clarification of a Directory
Date clarification request submitted: Date clarification response provided:
Contact information for person requesting the clarification:
Name:
Organization:
Telephone:
E-mail:
Identify the Directory that needs clarification:
Directory Number:
Directory Title:
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement:
Identify the material impact associated with this clarification:
Identify the material impact to your organization or others caused by the lack of clarity within this Directory:

Submit completed Request for Criteria Clarification forms to the NPCC Manager of Reliability Criteria.

Clarification: Response to Request for Clarification of Directory XX for the XXXX Corporation
The following clarification of Directory was developed by the Task Force on XXXXX
Directory Number and Text of Requirement
Question 1
Response to Question 1
Question 2
Response to Question 2

August, XX 2019

The Regional Standards Committee (RSC) Response to Comments Received in the Open Process Posting of the revised Directory Development and Revision Manual.

The RSC would like to thank those who provided comments on the proposed revisions to the NPCC Directory Development and Revision Manual which was posted from January 4, 2019 to February 18, 2019. The RSC responses to individual comments are provided below.

Comments from New Brunswick Power:

After a review of the proposed changes to the NPCC Directory Development and Revision Manual ("the Directory Manual") NBP has the following comments/recommendations.

Note that the comments extend beyond the Cost Effectiveness Analysis (CEA) process revisions.

Comment 1:

Suggest Modifying Directory/Criteria balloting process.

Consider modifying language in the Directory Manual such that the RCC does not approve Directories/Criteria in advance of balloting, but rather the RCC simply recommends that Directory/Criteria go to ballot.

With the present practice of the RCC approving a Directory prior to balloting, NPCC Members are losing an important opportunity to have the Directory vetted through the balloting process. Negative voting on a Directory should not be perceived as opposing the RCC initial approval, but rather seen as an opportunity to improve the Directory.

Rather than RCC approval prior to ballot, suggest that the RCC recommend for ballot based on stability in the development/revision phase (commenting/modifications not resulting in additional material changes) as well as meeting the intended reliability objective.

While this comment is not directly related to the CEA revisions being proposed, it should see a more rigorous review of Directories including CEA reviews during the development process.

RSC Response:

Comment accepted.

The RSC agrees that the final Member ballot should signify 'approval' of a document.

The Directory Manual approval process for NPCC criteria will be revised to reflect that the RCC approval reflects RCC concurrence that the document has been developed in accordance with relevant procedures and that the RCC approves conducting a Full Member ballot on its content in accordance with the NPCC Bylaws. (Page 7 and 11)

Comment 2:

Suggest adding guidance to tailor criteria based on CEA results.

Aspects of a proposed Directory may not be equally cost effective across the region or across all BPS facilities. Instead of simply seeking a "one size fits all" solution which may result in unnecessary added expense or abandoning a proposed Directory's reliability benefit, consider providing guidance on the CEA review to allow further refinement.

Suggested change in the text of VIII (5) below:

5. The Task Force shall use the information obtained, to make a determination if the revised or new Criteria is of sufficient reliability benefit to pursue further development activities by NPCC. If the benefit is prevalent to particular local areas, specific configurations or situations, consider tailoring the criteria applicability accordingly. Otherwise other cost effective approaches to achieve the reliability objective of the Criteria should be pursued. (E.g. development of a whitepaper, guideline document, etc.)

RSC Response:

Comment not accepted.

The NPCC By-Laws require a Full Member to abide by the NPCC criteria. The By Laws do not provide a local exclusion for compliance with the criteria.

Comment 3:

Suggest requiring approval when waiving CEA.

In looking at page 9 and 21: Suggest adding the text highlighted below to ensure that waiving the CEA process is approved.

1) Section VIII provides guidance for the CEA and Open Process posting. If the Lead Task Force determines that there is no benefit to conducting the CEA activity then this decision shall be documented and notification provided to the RCC and RSC along with the reasons for the decision to waive this portion of the process. The RCC may accept the Lead Task Force determination not to proceed with a CEA or request that a CEA be completed.

2) The Lead Task Force will document these activities as part of the record of development and notify the RCC and RSC of intent to conduct cost effectiveness analysis or exercise a waiver. The waiver will be subject to RCC approval.

RSC Response:

Comment accepted.

The Directory Manual cost effective review process will be revised to include a provision that provides for RCC approval of the Task Force determination not to proceed with a Cost Effective Analysis (CEA). (Page 22)

Comment 4:

Clarify Functional Entity Applicability

The applicability section of each Directory identifies those Functional Entities that are assigned reliability requirements. The Functional Entities appear to be based on the NERC functional model. While the NERC functional model has clear processes to identify and inform on applicability of NERC standards, there does not appear to be any process that aligns NPCC voluntary membership with the Functional Entities listed in the Directories.

A recommendation is to utilize the NPCC Full Member Sector Membership as the basis for determining Functional Entity.

Suggest including the wording in section III as follows:

III. APPLICABILITY OF NPCC CRITERIA

The requirements of an NPCC Directory apply only to those Full Member facilities defined as NPCC bulk power system elements as identified through the performance based methodology of NPCC Document A-10, "Classification of Bulk Power System Elements," the current list of which is maintained by the NPCC Task Force on System Studies and approved by the NPCC Reliability Coordinating Committee. For entities that may qualify for multiple Full Memberships, Full Membership sector representation will be the basis for determining Functional Entity applicability as listed in the Directory.

RSC Response:

Comment not accepted.

In accordance with the NPCC By Laws Members are eligible to vote in one of the seven (7) stakeholder voting sectors.

Members are assigned to voting sectors consistent with the Members business or other activities within NPCC and multiple memberships of separate business functions of an entity are permitted.

However, the By Laws require that a Full Member comply with the criteria, applicable to critical facilities as determined by the A-10 procedure.

Comment 5:

Comment on Generator Applicability

The Directories and the Directory manual identify generator applicability as only those BPS elements identified by the A-10 methodology. However, there may be a belief that generator applicability is based on an MVA threshold.

RSC Response:

Thank you for the comment.

Generator applicability to the NPCC criteria is in accordance with the provisions of the A-10 methodology and is not based on an MVA threshold.

Comments from the New York State Reliability Council, LLC:

Comment 1:

Agree with changes.

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

7/1/2019

Type	Document	Description	Comments	Status
Manual	Directory Manual	Directory Review and Revision Manual	Cost Effectiveness Revisions	Posting closed 2/18/2019. Pending comment review and further revisions from D4 and D5 cost effectiveness survey.
Directory	Directory #4	System Protection Criteria	Periodic review and cost effectiveness survey.	Posting closed 5/9/2019. TFSP reviewing comments.
Directory	Directory #5	Reserve	Periodic review and cost effectiveness survey.	Posting closed 5/17/2019. TFCO reviewing comments.
Directory	Directory #6	Reserve Sharing Groups	Periodic Review	Posting closed 6/1/2019. No comments received.

NPCC Directory Executive Tracking Summary

Revised: 7/1/2019

	Document	Title	Responsible Task Force	Latest Version	Comments	Status
Directories						
	Directory #1	Design and Operation of the Bulk Power System	TFCP	Oct-15	TFCP currently developing draft Scope of Work to guide 2020 Directory #1 review.	TFCP anticipates periodic review of Directory #1 in 2020.
	Directory #2	Emergency Operations	TFCO	Jun-18	TFCO completed periodic review in 2018.	Approved by Full Members June 29, 2018.
	Directory #3	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	Bulk Power System Protection Criteria	TFSP	Sep-15	TFSP periodic review and cost effectiveness survey.	Posting closed May 9, 2019. TFSP reviewing comments.
	Directory #5	Reserve	TFCO	Oct-12	TFCO periodic review and cost effectiveness survey.	Posting closed May 17, 2019. TFCO reviewing comments.
	Directory #6	Regional Reserve Sharing	TFCO	Apr-12	TFCO periodic review.	Posting closed June 1, 2019. (No comments)
	Directory #7	Special Protection Systems	TFSP	Jul-13	TFSP Reviewing D#7 Criteria; TFCP Coordinating Review of D#7 Appendix B.	Currently Under TFCP and TFSP Review.
	Directory #8	System Restoration	TFCO	Sep-18	TFCO completed periodic review in 2018.	Approved by Full Members September 25, 2018
	Directory #9	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	Verification of Generator Gross and Net Reactive Power Capability	TFCO	Dec-11		See D#9.
	Directory#11	Disturbance Monitoring	TFSP	Oct-16		
	Directory #12	Automatic UFLS	TFSS	Jul-13		
Criteria						
	A-10	Classification of BPS Elements	TFCP	Dec-09	CP-11 incorporating RCC approved recommendations.	Posting closed 7/01. TFCP/CP-11 reviewing comments.
Procedures						
	C-33 Procedure	Procedure for Analysis and Classificationof Dynamic Control Systems	TFSS	Retire	TFSS Proposing to Retire C-33	Pending TFCP and TFSS agreement on retirement.

NPCC Directory Criteria Clarifications

Revised: **4/18/2019** 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

4/18/2019

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	**30-Aug-18**	**Revisions to Directory #2 approved by the Full Members on 6/29/2018.**
July 1 to September 30, 2018	12/1/2018	**26-Nov-18**	**Revisions to D#8 and Retirement of A-01 approved by the Full Members on 9/25/2018**
October 1 to December 31, 2018	3/1/2019	N/A	No changes were made during the referenced period which required filing.

REGIONAL STANDARDS COMMITTEE

Chairman:

Guy V. Zito
Assistant Vice President - Standards
Northeast Power Coordinating Council, Inc.
Tel. (212) 840-1070
Email: gzito@npcc.org

Co-Vice Chairman:

Quintin Lee
Program Manager - Reliability Compliance
Eversource Energy
780 North Commercial Street
Manchester, NH 03101
Office: (603) 634-3579
Cell: (603) 315-9010
Email: quintin.lee@eversource.com

Co-Vice Chairman:

Michael Jones
Manager, Reliability Standards and Policy
National Grid
40 Sylvan Road
Waltham, Massachusetts 02451
Tel. (781) 907-2404
Email: michael.jones@nationalgrid.com

Sector 1 - Transmission Owners

Hydro One Networks, Inc.

Primary
Paul Malozewski, P. Eng., MBA, PMP
Senior Manager – Reliability Standards and Compliance Assurance
Tel. 416-345-5005
Email: paul.malozewski@hydroone.com

Alternate
Payam Farahbakhsh, M. Eng, P. Eng.
Senior Network Management Engineer – Reliability Standards and Compliance Assurance
Tel. (416) 345-5484
Email: Payam.Farahbakhsh@HydroOne.com

Consolidated Edison Company of New York, Inc.

Primary
Michael Forte
Chief Transmission Planning Engineer
Tel. (212) 460-3416
Fax (212) 529-1130
Email: fortem@coned.com

Alternate
Martin Paszek
Manager, System Performance
Tel. (212) 460-6415
Fax (212) 529-1130
Email: paszekm@coned.com

National Grid

Primary
John Hastings
Lead Analyst, Transmission Control Center – NY
7437 Henry Clay Blvd HCB-3
Liverpool, NY 13088
National Grid, US
Tel. (315) 460-4139
Email: John.Hastings2@nationalgrid.com

Alternate

New Brunswick Power Corporation

Primary
Laura Mcleod, P.Eng.
Corporate Compliance
515 King St, Fredericton NB, Canada E3B 5G4
Tel. (506) 458-6662
Email: laura.mcleod@nbpower.com

Alternate
Nurul Abser
Engineer IV, Compliance
Tel. (506) 458-3964
Cell. (506 238-3624
Email: NAbser@nbpower.com

The United Illuminating Company

Primary
Michele Tondalo
Lead Analyst – NERC Compliance (O&P)
180 Marsh Hill Road
Orange, Connecticut 06477
Tel. (203) 499-2542
Email: Michele.Tondalo@uinet.com

Alternate
Kristina Henderson, CPESC
Lead Analyst – NERC Compliance
89 East Avenue
Rochester, New York 14649
Tel. (585) 771-6153
Email: Kristina.Henderson@avangrid.com

Hydro-Quebec TransÉnergie

Primary
Caroline Dupuis, ing.
Acting Director – Reliability Standards and Regulatory Compliance
2 Complexe Desjardins, 19th floor, East Tower
Montréal, Québec, Canada H5B 1H7
Tel. (514) 879-4100 Ext: 5903
Email: dupuis.caroline@hydro.qc.ca

Alternate
Nicolas Turcotte
Acting Manager – Reliability Standards and Regulatory Compliance
2 Complexe Desjardins, 19th floor, East Tower
Montréal, Québec, Canada H5B 1H7
Tel. (514) 798-1223
Ext :8795182
Email: turcotte.nicolas@hydro.qc.ca

Orange & Rockland Utilities, Inc.

Primary
Nick Kowalczyk
Chief System Operator
390 West Route 59
Spring Valley NY 10977
Tel. (845) 577-3796
Email: kowalczykn@oru.com

Alternate
Susmit Patel
Section Manager – Substation & Transmission Engineering
Orange and Rockland Utilities Inc.
390 West Route 59
Spring Valley NY 10977
845-577-3203
Email: patels@oru.com

Eversource Energy

Primary
Quintin Lee
Program Manager - Reliability Compliance
Eversource Energy
780 North Commercial Street
Manchester, NH 03101
Office: (603) 634-3579
Cell: (603) 315-9010
Email: quintin.lee@eversource.com

Alternate
Sharon Flannery
Program Manager – Reliability Compliance
Eversource Energy
107 Selden Street
Berlin, CT
Office: (860) 665-5247
Cell: (860) 402-9157
Email: sharon.flannery@eversource.com

Sector (2) - Reliability Coordinators

New York Independent System Operator

Primary
Gregory A. Campoli
Manager, Reliability Compliance & Industry Affairs
Tel. (518) 356-6159
Email: gcampoli@nyiso.com

Alternate
James (Jim) Grant
Reliability Senior Engineer
Tel. (518) 356-6128
Email: jgrant@nyiso.com

ISO New England, Inc.

Primary
Kathleen M. Goodman
Senior Operations Compliance Coordinator
Tel. (413) 535-4111
Email: kgoodman@iso-ne.com

Alternate

Independent Electricity System Operator

Primary
Helen Lainis
Senior Engineer/Technical Officer
Tel. (905) 855-4106
Email: helen.lainis@ieso.ca

Alternate
Scott Berry
Senior Engineer/Technical Officer
Tel. (905) 403-6912
Email: scott.berry@ieso.ca

Hydro-Quebec TransÉnergie

Primary
Chantal Mazza
Reliability Standards Advisor III
2 Complexe Desjardins, 19th floor, East Tower
Montréal, Québec, Canada H5B 1H7
Tel. (514) 798-1223 Ext. 8795499
Email: mazza.chantal@hydro.qc.ca

Alternate
Michael Godbout
Engineer – Reliability Standards & Operating Procedures Reliability Coordinator
2 Complexe Desjardins, 13th floor, East Tower
Montreal, Québec, Canada H5B 1H7
Tel. (514) 798-1223 Ext. 8795852
Email: Godbout.Michael@hydro.qc.ca

New Brunswick Power Corporation

Primary
Randy MacDonald
Director, Corporate Compliance
Tel. (506) 458-4653
Cell. (506) 470-3536
Email: RaMacDonald@NBPower.com

Alternate
Tim Hicks
Document & Compliance Coordinator
Tel. (506) 458-6511
Cell. (506) 238-3851
Email: Tim.Hicks@nbpower.com

Sector (3) - Transmission Dependent Utilities ("TDUs"); Distribution Companies and Load-Serving Entities ("LSEs")

Consolidated Edison Company of New York, Inc.

Primary
Dermot Smyth
Senior Engineer
Tel. (212) 460-4093
Fax (212) 529-1130
Email: smythd@coned.com

Alternate
Christopher Overberg
Engineer
Tel. (212) 460-2915
Fax (212) 529-1130
Email: overbergc@coned.com

National Grid

Primary
Michael Jones
Manager, Reliability Standards and Policy
40 Sylvan Road
Waltham, Massachusetts 02451
Tel. (781) 907-2404
Email: michael.jones@nationalgrid.com

Alternate

Orange & Rockland Utilities, Inc.

Primary	Alternate
David Burke	Ben Wu
Senior Specialist - Compliance	Principal Engineer
Tel. (845) 577-2841	Transmission & Substation Engineering
Email: burkeda@oru.com	Tel. (845) 577-3713
	Email: wub@oru.com

Sector (4) - Generator Owners

Consolidated Edison Company of New York, Inc.

Primary	Alternate
Peter Yost	Daniel Valle
Manager, Standards & Compliance	Senior Engineer
Tel. (212) 460-2889	Tel. (212) 460-4734
Fax (212) 529-1130	Fax (212) 529-1130
Email: yostp@coned.com	Email: valleda@coned.com

New York Power Authority

Primary	Alternate
Salvatore Spagnolo	Tom Savin
Program Manager, Reliability Standards & Compliance	Program Manager, Reliability Standards & Compliance
Tel. (914) 390-8224	Tel. (914) 287-3151
Mob. (347) 992-7015	Email: Thomas.Savin@nypa.gov
Email: Salvatore.Spagnolo@nypa.gov	

Dominion Energy Services, Inc.

Primary	Alternate
Sean Bodkin	Connie Lowe
NERC Compliance Policy Manager	Regulatory and Market Policy Manager
Dominion Energy Services, Inc.	Dominion Energy Services, Inc.
Tel. (804) 771-8429, tie line 8-786-8429	Tel. (804) 771-4447, tie 8-736-4447
Cell: (804) 292-5721	Cell: 804-239-3201
Email: Sean.Bodkin@dominionenergy.com	Email: connie.lowe@dominionenergy.com

Ontario Power Generation, Inc.

Primary
Mike Cooke
Director – Reliability Compliance
Tel. (416) 592-6089
Cell: (905) 483-5520
Email: mike.cooke@opg.com

Alternate
David Kwan
Senior Regulatory Analyst
Tel. (416) 592-6369
Email: david.kwan@opg.com

Alternate
Constantin Chitescu
Regulatory Analyst
Tel. (416) 592-6055
Email: constantin.chitescu@opg.com

NextEra Energy, LLC

Primary
Silvia Parada Mitchell
Senior Director, Reliability Standards & Compliance
Tel. (561) 904-3767
Email: silvia.parada.mitchell@fpl.com

Alternate
Summer Esquerre
Director Reliability Standards & Compliance
Tel. (561) 904-3765
Email: summer.esquerre@fpl.com

Alternate
Rogelio Moraitis
Senior Compliance Analyst
Reliability Standards and Compliance
Tel. (561) 904-3402
Email: Rogelio.Moraitis@nee.com

Entergy Services, Inc

Primary
Glen Smith
NERC Compliance
Entergy Services, Inc
440 Hamilton Avenue
White Plains, NY 10601
914-272-3513
Email: gsmith@entergy.com

Alternate
Mark Thomas
Manager
NERC Compliance, Standards & Implementation
Tel: (501)228-2885
Email: mthoma3@entergy.com

PSEG

Primary
Sean Cavote
NERC Compliance and Advocacy
PSEG Law Department
80 Park Plaza, P3
Newark, NJ 07102-4194
973-430-5310
Email: sean.cavote@pseg.com

Alternate
Tim Kucey
Manager NERC/CIP Compliance - Fossil
40 Cragwood Road
South Plainfield, NJ 07080
908-412-3078
Email: Timothy.Kucey@PSEG.com

Sector (5) - Marketers, Brokers and Aggregators

Consolidated Edison Company of New York, Inc.

Primary
Ashmeet Kaur
Engineer
Tel. (212) 460-4155
Fax (212) 529-1130
Email: kaura@coned.com

Alternate
Qinling Zheng
Engineer
Tel. (212) 460-2790
Fax (212) 529-1130
Email: zhengq@ConEd.com

Utility Services, Inc.

Primary
Brian Robinson
Compliance Analyst
Tel. (802) 241-1400
Email: brian.robinson@utilitysvcs.com

Alternate
Brian Evans-Mongeon
President/CEO
Tel. (802) 241-1400
Email: brian.evans-mongeon@utilitysvcs.com

Sector (6) – State and Provincial Regulatory and/or Governmental Authorities

New York Power Authority

Primary
Shivaz Chopra
Director, Reliability Standards & Compliance
Tel. (914) 681-6828
Tel. (914) 391-6839
Email: shivaz.chopra@nypa.gov

Alternate
Erick Barrios
Engineer, Reliability Standards & Compliance
Tel. (914) 681-6781
Tel. (914) 506-2152
Email: Erick.Barrios@nypa.gov

New York State Department of Public Service

Primary	Alternate
Vijay Puran	Jerry Ancona
Utility Supervisor, Bulk Electric Systems	Senior Engineer
Tel. (518) 486-5948	Tel. (315) 448-7300
Email: vijay.puran@dps.ny.gov	Email: Jerry.Ancona@dps.ny.gov

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

New York State Reliability Council, LLC

Primary	Alternate
Alan Adamson	
Independent Consultant	
2104 Braxton Street	
Clermont, FL 34711	
Tel. (352) 989-4653	
Email: aadamson@nycap.rr.com	

Independent

Primary	Alternate
David Kiguel	
Independent Consultant	
Toronto, Canada	
Email: David.kiguel@outlook.com	

AESI, Inc.

Primary	Alternate
Joel Charlebois	
Vice President, Regulatory Compliance	
Tel. (770) 870-1630 x 236	
Cell: (718) 419-4012	
Email: JoelC@aesi-inc.com	

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Critical Infrastructure Protection Reliability Standard CIP-012-1 – Cyber Security – Communications between Control Centers	)))	Docket No. RM18-20-000

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

The North American Electric Reliability Corporation ("NERC") provides comments on the Federal Energy Regulatory Commission's ("FERC" or the "Commission") Notice of Proposed Rulemaking ("NOPR") proposing to approve Critical Infrastructure Protection ("CIP") Reliability Standard CIP-012-1 (Cyber Security – Communications between Control Centers).[1] NERC supports the Commission's proposal to approve the proposed Reliability Standard. As discussed in the NOPR, proposed Reliability Standard CIP-012-1 improves upon the currently effective CIP Reliability Standards by: (1) mitigating cyber security risks associated with communications between Bulk Electric System ("BES") Control Centers; (2) supporting situational awareness; and (3) protecting the confidentiality and integrity of Real-time Assessment and Real-time monitoring data transmitted between BES Control Centers.[2]

As provided in these comments, NERC does not support the Commission's NOPR proposal to direct modifications to the CIP Reliability Standards to: (1) require protections regarding the availability of communication links and data between BES Control Centers; and (2) provide additional specificity on the types of data that must be protected.[3] Instead of a directive to modify

[1] *Critical Infrastructure Protection Reliability Standard CIP-012-1 – Cyber Security – Communications between Control Centers,* 167 FERC ¶ 61,055 (2019) ("NOPR").

[2] NOPR at P 2.

[3] NOPR at P 4.

the CIP Reliability Standards, NERC proposes to conduct a study of the risks to availability of data and communication links between Control Centers to determine an appropriate course of action.

I. COMMENTS

NERC does not support the proposed directives. First, Section I.A discusses how the currently effective Reliability Standards and proposed CIP-012-1 already include requirements that help address the risks associated with the unavailability of communication links and data between Control Centers. As it is unclear whether any additional protections are both needed and feasible, NERC proposes to initiate a study on this issue rather than modify the CIP Reliability Standards. Second, Section I.B discusses how the language in proposed CIP-012-1 is sufficient for entities to identify the data subject to the proposed standard.

A. Proposed Directive to Modify Standard to Address Availability

In the NOPR, the Commission proposes to direct NERC to modify the CIP Reliability Standards to include availability protections for data and communication links between Control Centers. Availability is one of three information security objectives that cyber security protections seek to support.[4] In Order No. 822, the Commission noted that, "Protecting the availability of [BES] data involves ensuring that required data is available when needed for [BES] operations."[5]

[4] The National Institute of Standards and Technology ("NIST") defines Security Objective as "Confidentiality, integrity, or availability." *Special Publication 800-53 (Rev. 4) Security and Privacy Controls for Federal Information Systems and Organizations* app. B, at B-22 (2015), https://nvlpubs.nist.gov/nistpubs/SpecialPublications/NIST.SP.800-53r4.pdf ("NIST 800-53").

[5] *Revised Critical Infrastructure Protection Reliability Standards*, Order No. 822, 154 FERC ¶ 61,037 at P 54 n.60 (2016) ("Order No. 822").

The National Institute of Standards and Technology ("NIST") describes the following methods, among others, to protect availability of data:[6]

- Redundant or alternate systems or infrastructure.[7]
- Recovery of information systems.[8]
- Emergency disabling of encryption.[9]

Other controls can also help support availability. For example, the use of the same communications protocol between different entities helps to ensure entities can communicate effectively. Similarly, alerts on disruption of service help inform entities of when to perform corrective actions to receive the information needed in a timely manner.

As discussed further below, NERC does not support the Commission's proposed directive at this time. Existing NERC Reliability Standards provide protections of data and communication links between Control Centers, including some that align with the recommendations from the NIST framework. Instead of a directive to revise the CIP Reliability Standards, NERC proposes to conduct a study of the currently enforceable protections within NERC Reliability Standards, assess whether any risks to availability remain, and, if any residual risks are found, evaluate cost effective alternatives for addressing these risks.

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[6] These protection methods are highlighted in NIST 800-53 at 35 (citing to the control documents appended to the publication that provide additional detail on the controls) as ways to address availability.

[7] *See* NIST 800-53 app. F-CP at F-83 to F-87 (controls CP-6, CP-7, CP-8, and CP-9).

[8] *See* NIST 800-53 app. F-CP at F-87 to F-88 (control CP-10).

[9] *See* NIST 800-53 app. F-SC at F-195 to F-196 (control SC-12).

1. Existing NERC Reliability Standards, along with proposed CIP-012-1, help to address the risks related to unavailability of data and communication links between Control Centers.

As NERC explained in its petition for approval of proposed CIP-012-1, existing NERC Reliability Standards require entities to implement controls that help address the risks related to unavailability of data and communication links between Control Centers.[10] Several of NERC's existing Reliability Standards complement the CIP Reliability Standards and are designed to support availability, as that concept is understood in the information security sector, of data and communication links between Control Centers. These standards obligate entities to take steps to protect availability; the protection of availability is not merely an outcome. As a result, NERC would not duplicate these obligations in the CIP Reliability Standards in order to achieve NERC's reliability goals in an efficient and effective manner.

a. *NERC Reliability Standards support availability of data between Control Centers.*

Reliability Standards that require one or more availability protections are discussed below. Collectively, these protections help support the availability of data and communication links by: (1) requiring redundant data exchange infrastructure within Control Centers; (2) requiring a mutually agreeable security protocol for exchanging Real-time monitoring and Real-time Assessment data; (3) requiring entities to address data quality and to notify System Operators when Real-time monitoring alarm processors are not working properly; (4) requiring recovery plans for Control Center data exchange infrastructure that are medium and high impact BES Cyber Systems, or their associated Electronic Access Control or Monitoring Systems ("EACMS") or Physical Access Control Systems ("PACS"); (5) enabling entities to disable encryption during certain CIP

[10] *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard CIP-012-1* at 17-18, Docket No. RM18-20-000 (Sept. 18, 2018).

Exceptional Circumstances; and (6) requiring backup Control Center facilities or backup Control Center functionality.

i. IRO and TOP Reliability Standards

NERC developed the IRO and TOP Reliability Standards using availability of data as a guiding principle. In fact, one of the Reliability and Market Interface principles that the IRO and TOP Reliability Standards support is that "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."[11] (emphasis added) As a result, the requirements within the standards described below help to support availability.

As noted above, the NIST framework includes redundancy of infrastructure or systems as a control that supports availability. IRO-002-5 and TOP-001-4 require Reliability Coordinators ("RCs"), Balancing Authorities ("BAs"), and Transmission Operators ("TOPs") to have redundant and diversely routed data exchange infrastructure for Real-time Assessment and Real-time monitoring data within a Control Center.[12] As such, the requirements for diversely routed data exchange infrastructure for Real-time Assessment and Real-time monitoring data within Control Centers align with suggested protections of availability in the NIST framework.

While IRO-002-5 and TOP-001-4 cover infrastructure within Control Centers, not between Control Centers, the requirements help protect the availability of data to be exchanged between Control Centers. While located within the Control Center, the data exchange infrastructure in scope

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[11] *Standards Authorization Request Form* for Modifications to TOP and IRO Standards at 4, available in *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards IRO-002-5 and TOP-001-4*, Exhibit F at 174, Docket No. RD17-4-000 (Mar. 6, 2017); *Standards Authorization Request Form* for Project 2014-03 Revisions to the TOP/IRO Reliability Standards at 6, available in *Petition of the North American Electric Reliability Corporation for Approval of Proposed Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards*, Exhibit K at 483, Docket No. RM15-16-000 (Mar. 18, 2015).

[12] IRO-002-5, Requirement R2 and TOP-001-4, Requirement R20.

of these requirements facilitates sending and receiving data between Control Centers. If, for instance, an applicable entity lost capability of some of this data exchange infrastructure, the applicable entity could continue to send and receive data between Control Centers because of the redundant data exchange infrastructure within its Control Center. Thus, protections applied within a Control Center help support data exchange, as well as data availability, between Control Centers.

IRO-010-2 and TOP-003-3 require applicable entities to use a mutually agreeable security protocol between Control Centers.[13] This supports availability by helping to ensure that conflicting protocols do not impede receipt of data between Control Centers.

IRO-018-1(i) and TOP-010-1(i) require RCs, BAs, and TOPs to address data quality and to have an alarm process monitor that provides notification to System Operators when Real-time monitoring alarm processors are not working properly.[14] These protections serve to alert entities to potential issues with systems receiving the data so that entities can address them in a timely manner, as timeliness is an important component of availability.[15] These protections help to ensure information is available when needed.

ii. CIP Reliability Standards

As noted above, the NIST framework suggests recovery of information systems as a control to support availability. Reliability Standard CIP-009-6 requires Responsible Entities to have, implement, and maintain recovery plans for medium and high impact BES Cyber Systems and their associated EACMS and PACS at Control Centers. The recovery plans can include the systems and infrastructure facilitating data exchange between Control Centers. Recovery of these systems

[13] IRO-010-2, Requirement R3 and TOP-003-3, Requirement R5.

[14] IRO-018-1(i), Requirements R1 and R3; TOP-010-1(i), Requirements R1 and R4.

[15] *See* NIST 800-53 app. B at B-2 (defining Availability as "Ensuring timely and reliable access to and use of information.").

helps to ensure that data continues to be available. Thus, the recovery plans help to support availability for certain data exchange systems used by Control Centers.

Proposed CIP-012-1 includes a provision for CIP Exceptional Circumstances ("CEC") in Requirement R1, which allows Responsible Entities to disable encryption of data if necessary. For example, if the entity's encryption system is not working, the entity could review whether the situation qualifies as a CEC and, if so, disable the encryption controls to support availability of needed data. As discussed above, disabling encryption controls is one suggested control for supporting availability according to the NIST framework.

b. NERC Reliability Standards support availability of communication links.

Reliability Standard EOP-008-2 helps support the availability of communication links between Control Centers by requiring RCs to have backup Control Center facilities, or backup Control Center functionality for BAs and TOPs, in addition to their primary Control Centers. These backup facilities supply redundancy of some communication links and data exchange infrastructure and capabilities at the backup Control Center.[16] For entities with geographically diverse primary and backup Control Centers, some communication links are physically separate from one another. While geographic diversity alone will not always provide redundancy of communication links, having backup Control Centers with different paths to communicate with other Control Centers helps support availability of communication links.

c. NERC does not seek to duplicate obligations in the CIP Reliability Standards that exist in other Reliability Standards.

The protections described above directly support availability and must be implemented to comply with the standards. NERC does not support duplicating these same protections within the CIP standards. As stated in Order No. 693, "While a Reliability Standard does not necessarily need

[16] EOP-008-2, Requirement R3.

to reflect the optimal method for achieving its reliability goal, a Reliability Standard should achieve its reliability goal effectively and efficiently."[17] As such, NERC seeks to ensure that its suite of Reliability Standards are effective and efficient and do not duplicate protections. Duplicating protections is not needed for reliability and can create unnecessary administrative and compliance burdens on entities.

In fact, consistent with the objective for effective and efficient Reliability Standards, NERC is undertaking a Standards Efficiency Review initiative to help ensure that Reliability Standards support reliability in a clear and concise manner and do not duplicate requirements.[18] As part of this initiative, NERC is proposing retirement of redundant requirements whose required performance is inherent to the performance of other Reliability Standard requirements.[19] Obligating Responsible Entities to implement protections under the CIP Standards that are required under other standards would be contrary to the goal of efficiency and to initiatives designed to further that goal.

2. In lieu of a directive, NERC proposes to conduct a study to assess whether additional protections for availability of data and communication links between Control Centers are needed and feasible.

As noted in Section I.A.1 above, existing Reliability Standards require entities to implement controls that help mitigate the risks related to unavailability of data and communications links. NERC recognizes that there may be additional controls that could help address these risks. NERC understands, however, that many of these controls would involve communication links that are owned by a third-party telecommunications provider. There may be

[17] Order No. 693 at P 5.

[18] Information on the Standards Efficiency Review initiative is available at https://www.nerc.com/pa/Stand/Pages/Standards-Efficiency-Review.aspx.

[19] *See Petition of the North American Electric Reliability Corporation for Approval of Revised and Retired Reliability Standards Under the NERC Standards Efficiency Review*, Docket No. RM19-17-000 (June 7, 2019).

challenges for Responsible Entities to develop, implement, and enforce required controls for those third-party links. Moreover, depending on the magnitude and type of controls, some may be infeasible to implement. Assessing the feasibility of any additional protections is consistent with the Commission's charge for NERC to address the risk to availability with controls that can be "implemented in a reasonable manner."[20] As a result, a data-driven approach to considering the risks, such as a study, will help to address this issue in the most efficient and effective manner.

Based on these considerations, NERC does not support a directive to modify the Reliability Standards to address availability at this time. Instead, NERC proposes that the Commission accept a commitment from NERC to study the risks to availability of data and communication links between Control Centers and the current controls that support availability. Specifically, NERC plans to consider the following in its study: (1) how Control Centers communicate with one another; (2) ownership of communication links; (3) how Responsible Entities work with vendors to support availability of communication links; (4) controls used to support resiliency and availability of data and communication links; and (5) feasibility of Responsible Entities' implementing controls when communication links are owned by organizations not subject to NERC Reliability Standards. This study will help NERC determine the reasonableness of developing mandatory standards to require additional controls, if warranted, or take another appropriate and feasible course of action based on the resulting analysis. NERC should have the opportunity to appropriately scope the study, conduct the study, and develop a fuller record prior to engaging in any standards development activity, if necessary. If the Commission accepts NERC's commitment, NERC would submit a report to FERC within 18 months of the effective date of CIP-012-1.

[20] NOPR at P 20.

B. Proposed Directive to Modify Standard to Further Identify the Data in Scope

In the NOPR, the Commission noted that Real-time monitoring is not a NERC Glossary definition.[21] The Commission also asserted that proposed CIP-012-1 does not specify the types of data to be protected. As a result, the Commission proposed a directive to identify the types of data to be protected. The Commission also sought comments on whether NERC should define Real-time monitoring data. As explained below, further identification of the data, such as through the development of a NERC Glossary definition of Real-time monitoring, is not needed in proposed CIP-012-1.

The language used in proposed Reliability Standard CIP-012-1, "Real-time Assessment and Real-time monitoring data," is sufficient to identify the data as described in TOP-003-3 and IRO-010-2. Aside from proposed CIP-012-1, the IRO and TOP families are the only currently enforceable Reliability Standards that use the phrase "Real-time monitoring" and the term "Real-time Assessments." Reliability Standards TOP-003-3 and IRO-010-2 require entities to maintain data specifications, including minimum criteria, for the data necessary to perform Real-time monitoring and Real-time Assessments.[22] Compliance with these standards defines the data that is used in Real-time monitoring and Real-time Assessments. By using this language that is only referenced in the IRO and TOP Reliability Standards families, proposed CIP-012-1 brings the data identified pursuant to TOP-003-3 and IRO-010-2 into scope. As such, NERC does not support further identification of the data protected under proposed CIP-012-1.

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[21] NOPR at P 3. The Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary") is at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

[22] IRO-010-2, Requirement R1 and TOP-003-3, Requirements R1 and R2.

While a cross-reference to the standards where the data is defined may help to reiterate the scope of data, NERC does not believe it is necessary given the sufficiency of the language used in proposed CIP-012-1 and the administrative upkeep of adding a cross-reference.

Furthermore, a NERC Glossary definition for "Real-time monitoring" in proposed CIP-012-1 could have the unintended consequence of narrowing the scope of data subject to the standard. A definition of "Real-time monitoring" specific to CIP-012-1 may not capture all the data used to perform Real-time Assessments and Real-time monitoring as identified in a data specification under TOP-003-3 or IRO-010-2 if an entity identified data not included in the definition. This may inadvertently lead to some of this data not being protected under CIP-012-1. However, under the currently proposed CIP-012-1, this data would be in scope and subject to CIP-012-1 protections.

II. CONCLUSION

NERC respectfully requests that the Commission consider these comments and approve proposed Reliability Standard CIP-012-1.

Respectfully submitted,

/s/ Marisa Hecht

Lauren Perotti
Senior Counsel
Marisa Hecht
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
lauren.perotti@nerc.net
marisa.hecht@nerc.net

Counsel for the North American Electric Reliability Corporation

Date: June 24, 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RM15-11-003**

FIRST INFORMATIONAL FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION REGARDING WORK PERFORMED UNDER THE GEOMAGNETIC DISTURBANCE RESEARCH WORK PLAN

Lauren A. Perotti
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
lauren.perotti@nerc.net

Counsel for the North American Electric Reliability Corporation

July 26, 2019

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RM15-11-003**

FIRST INFORMATIONAL FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION REGARDING WORK PERFORMED UNDER THE GEOMAGNETIC DISTURBANCE RESEARCH WORK PLAN

Pursuant to paragraph 77 of Order No. 830,[1] the North American Electric Reliability Corporation ("NERC")[2] hereby submits an informational filing regarding the results of research performed to date under the NERC Geomagnetic Disturbance Research Work Plan ("GMD Research Work Plan"). The purpose of the GMD Research Work Plan is to conduct research on topics related to geomagnetic disturbances ("GMD") and their impacts on the reliability of the Bulk Power System ("BPS"). The GMD Research Work Plan consists of nine broad research "Tasks," along with associated deliverables and timetable for completion. NERC submitted the plan in its current form to the Commission on April 19, 2018,[3] and it was accepted by the Commission in Order No. 851.[4]

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[1] Order No. 830, *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 156 FERC ¶ 61,215, at P 77 (2016), *reh'g denied*, Order No. 830-A, 158 FERC ¶ 61,041 (2017) ("Order No. 830").

[2] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

[3] *See Revised Geomagnetic Disturbance Research Work Plan of the North American Electric Reliability Corporation*, Docket No. RM15-11-003 (April 19, 2018) at Attachment 1.

[4] Order No. 851, *Geomagnetic Disturbance Reliability Standard; Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 165 FERC ¶ 61,124, at P 65 (2018) ("Order No. 851").

I. BACKGROUND

In Order No. 830, the Commission approved Reliability Standard TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events.[5] In this order, the Commission also directed NERC to submit a work plan describing how NERC would conduct research on the GMD-related topics specified by the Commission and any additional topics selected in NERC's discretion and subsequently, one or more informational filings addressing the results of this research.[6]

NERC submitted a preliminary GMD Research Work Plan on May 30, 2017.[7] On October 19, 2017, the Commission accepted NERC's preliminary work plan and directed NERC to file a final, or otherwise updated, plan within six months.[8] As noted above, the Commission accepted NERC's revised GMD Research Work Plan in Order No. 851.

II. GMD RESEARCH WORK PLAN PROGRESS UPDATE

The GMD Research Work Plan is progressing on schedule with the engagement of the Electric Power Research Institute ("EPRI"), electricity sector participants, U.S. national laboratories, equipment manufacturers, and other North American research collaborators. Through this research, NERC and its collaborators expect to improve the capabilities and accuracy of GMD Vulnerability Assessments[9] performed by NERC entities and help ensure the

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5 Order No. 830 at P 22.

6 Order No. 830 at P 77.

7 *Geomagnetic Disturbance Research Work Plan of the North American Electric Reliability Corporation*, Docket No. RM15-11-002 (May 30, 2017).

8 *Order on GMD Research Work Plan*, 161 FERC ¶ 61,048, at PP 1 and 12 (2017).

9 GMD Vulnerability Assessment is defined in the *Glossary of Terms Used in NERC Reliability Standards* as "Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances."

effectiveness of GMD Reliability Standards in reducing risks to the BPS from severe GMD events.

EPRI has initiated a $3.6 million, multi-year project for GMD research. Earlier in 2019, EPRI released technical reports summarizing the results of significant research efforts to date. These reports have been made publicly available free of charge by EPRI and are summarized below.[10] NERC provides opportunities for technical and scientific review of EPRI's research results through the NERC GMD Task Force.[11]

Work on the EPRI project continues through 2019, with remaining research scheduled to conclude before the end of the first quarter in 2020. EPRI will continue to provide technical reports to the GMD Task Force for broad technical and scientific review.[12] NERC encourages anyone who is interested in NERC's GMD research activities to participate in GMD Task Force meetings. These meetings are open to the public, and remote participation is available.

Below is a summary of work completed under the GMD Research Work Plan to date, organized by specific GMD Research Work Plan task.

A. Task 1: Further Analyze Spatial Averaging Used in the Benchmark GMD Event

EPRI collaborated with researchers at the Los Alamos National Lab ("LANL") to develop a comprehensive data set that will analyze severe GMD event characteristics. The data set and analysis are part of research in Task 1: *Further Analyze Spatial Averaging Used in the*

[10] The cost to execute the research components of the plan is shared among NERC and electricity sector participants through a research program executed by EPRI.

[11] The NERC GMD Task Force is open to the public and includes participants from U.S. and Canadian government space weather researchers, representatives from the manufacturer and vendor community, and subject matter experts from both within and outside the electric power industry.

Additional information on the GMD Task Force is available on NERC's website at https://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

[12] As an independent research organization, EPRI will make the final decision on format and findings in its research results.

Benchmark GMD Event. Researchers obtained and processed magnetic field data from a global consortium of magnetic observatories to create a single data set to analyze large GMD events across all available magnetometer stations. Based on analysis of the data set, the report highlights how strong GMD hazards can be organized by the auroral oval location and notes the expansion of the auroral zone, towards the pole and equator, during strong geomagnetic activity. Further, it is noted that different times of day may have different geomagnetic hazard characteristics. Finally, the report affirms the value of high resolution magnetic time series (sampling periods shorter than 1 minute) to accurately estimate geoelectric fields.

Researchers will use this comprehensive data set for additional Task 1 activities as well as research into the effects of geomagnetic latitude on geoelectric fields during severe GMD events (Task 2: *Further Analyze Latitude Scaling*) as called for in the GMD Research Work Plan. The efforts in Tasks 1 and 2 will continue until the end of 2019 and, when complete, are expected to offer improved understanding of severe GMD event characteristics and the potential effects that they can have on the BPS.[13]

B. Task 2: Further Analyze Latitude Scaling

EPRI collaborated with researchers at the National Aeronautics and Space Administration ("NASA") to review recent research into the effects of geomagnetic latitude on geoelectric fields.[14] This review and analysis are part of research in Task 2: *Further Analyze Latitude Scaling*. Researchers performed an in-depth review of recent peer-reviewed published work, including work by the United States Geological Survey and LANL, on the variation in

[13] In an initial published report, EPRI described the data set and provided some initial observations. *See* EPRI Technical Update report, *Improving Understanding of Characteristics of Geoelectric Field Enhancements Caused by Severe GMD Events*, June 2019, https://www.epri.com/#/pages/product/3002016832/.

[14] *See* EPRI Technical Update report, *Review of Peer-Reviewed Research Regarding the Effects of Geomagnetic Latitude on Geoelectric Fields*, June 2019, https://www.epri.com/#/pages/product/3002016885/.

geoelectric field with respect to geomagnetic latitude that can be attributed to the source electric current systems in the atmosphere (i.e., geomagnetic latitude scaling). The report highlighted new ways to analyze the geomagnetic data (e.g., via conditioning with global geomagnetic indices and other relevant parameters, utilizing historical records of extreme storms, and modern geospace models).

These highlighted methods are part of the efforts in Task 1 and 2 that will continue until the end of 2019 and when complete will offer additional insights into the geomagnetic latitude scaling under severe space weather conditions.

C. Task 3: Improve Earth Conductivity Models for Geomagnetically Induced Current ("GIC") Studies

EPRI analyzed estimates of peak geoelectric fields for the Benchmark GMD Event[15] as derived from one-dimensional ("1D") and three-dimensional ("3D") earth conductivity models and published the results in a technical report.[16] This research, which is part of GMD Research Work Plan Task 3: *Improve Earth Conductivity Models*, helps to evaluate the performance of existing 1D conductivity models against models derived from new magnetotelluric measurement data, where available.[17]

NERC and its stakeholders will consider these results, along with the results of ongoing research being performed under Task 3, in order to refine the earth conductivity models and

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[15] The Benchmark GMD Event is used by NERC Entities in performing GMD Vulnerability Assessments. See the Benchmark GMD Event description here: https://www.nerc.com/pa/Stand/TPL0071RD/Benchmark_clean_May12_complete.pdf.

[16] Results of this research are published in EPRI Technical Update report, *Use of Magnetotelluric Measurement Data to Validate/Improve Existing Earth Conductivity Models*, January 2019, https://www.epri.com/#/pages/product/3002014856/.

In furtherance of earth conductivity model research, EPRI used geoelectric field calculation algorithms that were developed and benchmarked as specified in GMD Research Work Plan Task 7:*Geoelectric Field Evaluation and Calculation of Beta Factors. See* EPRI Technical Update report, *Tool Evaluation and Electric Field Estimate Benchmarking Results*, January 2019, https://www.epri.com/#/pages/product/3002014853/.

[17] Magnetotelluric data is not available for much of the southern continental U.S. *See* Figure 7-8 in the EPRI Report.

technical guidance that inform NERC entities in performing GMD Vulnerability Assessments. Following completion of the remaining GMD Research Work Plan Task 3 activities, NERC will evaluate whether the research findings may inform potential enhancements to the TPL-007 Reliability Standard. NERC expects the remaining GMD Research Work Plan Task 3 activities to conclude at the end of 2019.

D. Task 6: Section 1600 Data Request

In addition to overseeing the GMD Research Work Plan, NERC continues to develop the necessary processes and systems to implement GMD Research Work Plan Task 6: *Section 1600 Data Request*. In August 2018, the NERC Board of Trustees authorized NERC to issue a data request under Section 1600 of the NERC Rules of Procedure to collect GMD monitoring data from U.S. registered entities. The data request was developed by NERC staff and the GMD Task Force. NERC is finalizing the data reporting instructions that will guide reporting entities on how to submit the required GIC monitor data or magnetometer data that has been recorded during severe GMD events. Work to develop the necessary processes and technology solutions to collect and host the GMD monitoring data is ongoing. NERC anticipates beginning data collection in 2020.

E. Task 8: Improve Harmonics Analysis Capability

EPRI released a beta version of an open-source software tool for performing wide-area harmonic impact assessment.[18] This tool is the objective for GMD Research Work Plan Task 8: *Improve Harmonics Analysis Capability*. Completion of the development of this tool is expected at the end of 2019. The tool will provide Transmission Planners, Planning Coordinators and other users with wide-area harmonics assessment capability that is not currently available in

[18] *See* EPRI Software Product *GIC HARM V.0.0*, January 2019, https://www.epri.com/#/pages/product/3002014854/.

commercial software packages. EPRI has made the beta version of the software tool publicly available, and stakeholders are encouraged to provide feedback to inform development and publication of the final version. This capability will improve the accuracy of GMD Vulnerability Assessments required by the TPL-007 standard. Once completed, this tool will complete GMD Research Work Plan Task 8.

F. Task 9: Harmonic Impact Studies

Working with utilities and transformer manufacturers, EPRI performed analysis to assess potential impacts of vibrations due to GMD-related harmonics on power transformers.[19] This research informs GMD Research Work Plan Task 9: *Harmonic Impact Studies*. Researchers based the report on factory and field test data of power transformers and analysis of a population of transformers that have been exposed to a large number of strong solar storms. They concluded that long-term exposure to vibrations caused by GIC does not adversely affect transformer mechanical integrity. Furthermore, the research indicates that a severe GMD event is not likely to lead to transformer mechanical damage from vibrations because factory tests show that tank vibrations reach their maximum at lower levels of GIC and do not increase further when GIC levels continue to rise. To further validate the findings, EPRI intends to continue to perform long-term monitoring of tank vibrations of large power transformers in the field.

Publication of this report concludes GMD Research Work Plan Task 9 activities related to transformer vibration impacts due to GMD-related harmonics. Research into generator harmonic assessment is underway and expected to conclude by the end of 2019.

[19] *See* EPRI Technical Update report, *Impact of Geomagnetically Induced Currents on Transformer Tank Vibrations,* January 2019, https://www.epri.com/#/pages/product/3002014855/.

III. CONCLUSION

Since commencing the GMD Research Work Plan in December 2017, NERC, EPRI, and the electricity sector and research collaborators have made significant progress in achieving established GMD research goals. The project remains on schedule for completion at the end of 2019. NERC will submit one or more informational filings in future months to keep the Commission informed of the results of ongoing research.

Respectfully submitted,

/s/ Lauren A. Perotti

Lauren A. Perotti
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
lauren.perotti@nerc.net

Counsel for the North American Electric Reliability Corporation

July 26, 2019

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 the above-referenced proceeding.

Dated at Washington, D.C. this 26th day of July, 2019.

/s/ Lauren A. Perotti

Lauren A. Perotti
Counsel for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FIVE-YEAR ELECTRIC RELIABILITY ORGANIZATION PERFORMANCE ASSESSMENT REPORT IN ACCORDANCE WITH 18 C.F.R. § 39.3(c)

James B. Robb
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road NE, Suite 600
Atlanta, GA 30326
(404) 446-2567

Nina H. Jenkins-Johnston
Senior Counsel

Lauren Perotti
Senior Counsel

Candice Castaneda
Counsel

North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, DC 20005
(202) 400-3000
(202) 644-8099 – facsimile
nina.johnston@nerc.net lauren.perotti@nerc.net candice.castaneda@nerc.net

Counsel for the North American Electric Reliability Corporation

July 22, 2019

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket Nos. _____**

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FIVE-YEAR ELECTRIC RELIABILITY ORGANIZATION PERFORMANCE ASSESSMENT REPORT IN ACCORDANCE WITH 18 C.F.R. § 39.3(c)

The North American Electric Reliability Corporation ("NERC") respectfully submits its Five-Year Electric Reliability Organization ("ERO") Performance Assessment Report ("Performance Assessment") for the 2014-2018 Assessment Period[1] in accordance with the requirements of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations at 18 C.F.R. § 39.3(c) (2018) and the directives in Order No. 672.[2] As required by 18 C.F.R. § 39.3(c)(1), this Performance Assessment:

(i) identifies how the ERO Enterprise's[3] activities and achievements during the Assessment Period build upon the certification criteria of 18 C.F.R. § 39.3(b);

(ii) evaluates the effectiveness of each Regional Entity in carrying out its Delegated Authority; and

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1 The Assessment Period runs between June 1, 2014 – December 31, 2018.

2 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006). NERC was certified by the Commission as the ERO, pursuant to § 215(c) of the Federal Power Act ("FPA"), by Commission order issued July 20, 2006. *Order Certifying the North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006).

3 The ERO Enterprise is comprised of NERC and its seven Regional Entities: (i) Florida Reliability Coordinating Council, Inc. ("FRCC"); (ii) Midwest Reliability Organization ("MRO"); (iii) Northeast Power Coordinating Council, Inc. ("NPCC"); (iv) ReliabilityFirst Corporation ("ReliabilityFirst"); (v) SERC Reliability Corporation ("SERC"); (vi) Texas Reliability Entity, Inc. ("Texas RE"); and (vii) Western Electricity Coordinating Council ("WECC"). The ERO Enterprise will consist of six Regional Entities on August 31, 2019 when FRCC ceases to be a Regional Entity.

(iii) addresses stakeholder comments on NERC's performance (specific comments attached as directed by the Commission in the 2014 Five Year Order).[4]

NERC requests that the Commission accept this Performance Assessment.

[4] *Order on the Electric Reliability Organization's Five-Year Performance Assessment*, 149 FERC ¶ 61,141, at P 70 (2014) ("2014 Five Year Order").

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

Nina H. Jenkins-Johnston
Senior Counsel
North American Electric Reliability Corporation
3353 Peachtree Road N.E., Suite 600
North Tower
(404) 446-9650
nina.johnston@nerc.net

Charles A. Berardesco
Senior Vice President and General Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
charles.berardesco@nerc.net

II. INTRODUCTION

The ERO Enterprise is facing unprecedented, rapid change in the electric industry, which raises new challenges to and opportunities for the reliability and security of the Bulk Power System ("BPS"). Over the past five years, the ERO Enterprise has been navigating these changes by its leveraging tools, such as its assessments, as well as its subject matter expertise to identify and propose steps to reduce existing and emerging risks to reliability. Through its assessments of the state of reliability, NERC has demonstrated that there is improved resilience, decreased protection system misoperations, and advanced risk management for the BPS.[5]

[5] The following key indicators show how NERC is managing risks to improve the reliability of the BPS during the Assessment Period: (i) there were no non-weather Category 4 or Category 5 events; (ii) the protection system misoperation rate continues to decline; (iii) frequency response shows improvement; and (iv) the BPS experienced no loss-of-load due to cyber or physical security events, despite continually evolving threats.

Reliability and security of the BPS is fundamental to national security, economic development, and public health and safety. A major disruption in electric service due to extreme weather, equipment failure, a Cyber Security Incident, or a physical attack could have far-reaching effects. Users, owners and operators of the BPS must therefore institute measures to protect against and to mitigate an impact to the BPS stemming from both conventional risks (e.g., extreme weather and equipment failures) and emerging security risks, such as physical attacks intended to damage or disable critical elements of the BPS. Throughout the Assessment Period, the ERO Enterprise implemented several initiatives, described below, to better protect against risks to the BPS. These efforts, done in coordination with the Commission and stakeholders, build on programs highlighted in the 2014 Performance Assessment.[6]

A. Identifying and Assessing Emerging Risks

The ERO Enterprise effectively identifies, prioritizes and mitigates risks to the BPS. In addition to its traditional reliability assessments, the ERO Enterprise draws from its varied sources and coordinates across its functions to better understand risks emerging from the changing electric industry.

In 2014, a polar vortex ("2014 Polar Vortex") tested the resilience of the North American BPS. This event demonstrated how extended periods of cold temperatures have direct impacts on generator resource availability. Higher than expected forced outages were observed during the 2014 Polar Vortex (particularly for natural-gas-fired generators) as well as higher-than forecasted peak demand. An analysis of the Generator Availability Data System ("GADs") following this event highlighted the interdependencies of gas and electricity providers. Since the 2014 Polar Vortex, there have been significant efforts to improve generator performance during severe cold

[6] *North American Electric Reliability Corporation, Five-Year Electric Reliability Organization Performance Assessment Report*, Docket No. RR14-5-000 (July 21, 2014).

weather. During subsequent winter periods, there were also marked improvements in forced outage rates. Tools like SAFNR[7] help ensure that the ERO Enterprise is aware of any pressing needs of the BPS with near Real-time information. SAFNR specifically allows NERC to coordinate with critical infrastructure operators, federal and local agencies and authorities during an event or severe weather. NERC is working to enhance the SAFNR tool to include features such as geospatial views of the BPS.

NERC is also improving the content of its databases. To keep pace with the changing resource mix, NERC needs data from all types of generating resources that may have an impact on reliability. In addition to traditional generation, GADS performance data now captures wind generation. NERC developed wind turbine generation data reporting instructions to assist wind plant personnel in reporting information to the GADS application. Wind plants with a Total Installed Capacity of 75 MW or more, with a commissioning date of January 1, 2005 or later, will be required to report on a set schedule. In addition to wind generation, NERC is leveraging its technical standing committees, specifically the Planning Committee, to determine appropriate data reporting requirements for solar data, in anticipation of a potential Section 1600 data request detailing what specific data NERC will collect.

During the Assessment Period, NERC targeted emerging risks to reliability. The Reliability Issues Steering Committee ("RISC") is an advisory committee that reports directly to the NERC Board of Trustees ("NERC Board") regarding BPS reliability issues and how to address them. In its biennial report, the RISC identifies and ranks BPS reliability risks to industry. In this report, the RISC makes recommendations to the NERC Board on actions that the ERO could take to address reliability risks. The RISC identified the changing resource mix as a risk area and

[7] Situational Awareness for FERC, NERC and the Regional Entities ("SAFNR").

advised the NERC Board to augment ERO Enterprise systems, as discussed herein, to gather data to better evaluate the implications of the changing resource mix. The RISC was also involved with the ERO Enterprise's efforts to address inverter-based resource controls, protection, and performance issues during the Assessment Period. NERC posted Alerts[8] in 2017 and 2018 to address this issue and formed a joint Inverter-Based Resource Performance Task Force to develop guidelines and recommended practices for inverter-based resources connected to the BPS. The RISC charged the Inverter-Based Resource Performance Task Force with ensuring that its efforts include addressing any gaps in NERC Reliability Standards. This example reflects the steps that the ERO Enterprise, working collaboratively with industry, has taken to better understand the changing resource mix, to identify mitigation solutions, to monitor their implementation.

[8] NERC often either discovers, identifies, or is provided with information that is critical to ensuring the reliability of the BPS in North America. In order to effectively disseminate this information, NERC utilizes email-based Alerts designed to provide concise, actionable information to the electricity industry.

B. NERC Reliability Standards are Addressing Planning, Cyber Security, and Physical Security Risks to the Bulk Electric System

NERC's mandatory and enforceable Reliability Standards define the reliability requirements for planning and operating the North American BES and securing the facilities, systems, and equipment underlying the efficient and effective operation of the BPS. In 2007, the Commission approved the first set of mandatory Reliability Standards in Order No. 693. In subsequent years, NERC invested significant resources to develop new and revised mandatory Reliability Standards to address Commission directives and emerging risks. NERC also invested significant time and effort to improve the quality, content, and organization of Reliability Standards.

During the Assessment Period, NERC reached a new level of maturity in its Reliability Standards development program. At the outset of the Assessment Period, NERC focused on addressing outstanding FERC directives from Order No. 693 and improving the initial set of Reliability Standards. Through the ERO's experience completing over 100 Reliability Standards projects, NERC is refining its approach to determine when a Reliability Standard is necessary to address a reliability risk as well as how to draft a Reliability Standard. NERC's approach to developing Reliability Standards consists of several key elements, including the following:

(i) use a results-based approach that focuses on performance, risk management, and entity capabilities, rather than prescribing specific processes for an entity to follow;

(ii) focus on advancing reliability and not prescribe commercial business practices; and

(iii) avoid duplication and conflict among requirements.

The body of NERC Reliability Standards now largely reflects a set of risk-based Reliability Standards.

As this foundational work concluded, NERC shifted more of its focus to the following:

(i) identifying new and emerging risks that may require new or revised Reliability Standards;

(ii) refining processes to create synergies between subject matter experts from NERC's various functions and standards so that the ERO can better identify areas to improve the effectiveness and efficiency of the Reliability Standards; and

(iii) enhancing its processes surrounding the development of Reliability Standards.

In order to identify new and emerging reliability risks as well as the optimum tool to address those reliability risks for the NERC Board (i.e., guidelines or a new or revised Reliability Standard), NERC must strengthen the synergies between its Reliability Standards and the feedback channels listed below:

(i) input and recommendations from the RISC and NERC's technical standing committees;

(ii) data from the Compliance Monitoring and Enforcement Program ("CMEP"), including the evaluation of compliance violation statistics, and reported of areas of concern, among others;

(iii) data and lessons learned from Events Analysis;

(iv) Commission input, including through the FERC technical conference;

(v) areas highlighted in the State of Reliability Report [9] and other reliability assessments; and,

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(vi) Regional Entity feedback.

NERC recognizes that the synergy between each of these channels and Reliability Standards varies and NERC strives to improve them. Below are several examples of how the ERO's maturing synergies with the above-mentioned channels have impacted Reliability Standards development:

(i) Standard drafting teams have leveraged cause coding efforts of the event analysis function to inform themselves of the magnitude of risk associated with a Reliability Standard requirement. The purpose of cause coding is to provide a structured, measurable, and continuously improvable approach to characterize the causes of reportable events and eventually to develop actionable BPS risk reduction knowledge. Standard drafting teams can identify characteristics of events (i.e., cold weather, EMS outage, or breaker failure) by running a query to gather information regarding any given risk. During the development of Reliability Standard EOP-004-4 (Event Reporting), the standard drafting team leveraged cause coding data to refine which event types require reporting, which thresholds are appropriate to trigger event reporting, as well as which entities should have reporting responsibility.

(ii) NERC's technical standing committees also provide feedback to standard drafting teams, especially in the analysis of emerging issues and development of industry guidelines. In 2017, following the issuance of NERC's report on the August 2016 Blue Cut Fire Disturbance, NERC formed the Inverter-Based Resource Performance Task Force, which reports jointly to the Operating Committee and the Planning Committee. The goal of this Task Force was to study, among other things, the impacts of inverter momentary cessation. The Task Force first developed a whitepaper and a guideline on BPS-Connected Inverter-Based Resource Performance. In 2018, this Task Force prepared an analysis of the Reliability Standard PRC-024 (Generator Frequency and Voltage Protection Settings) and identified opportunities to improve the standard by addressing potential issues associated with inverter-based resources. A standard development project is now underway to address the Task Force's recommendations.

(iii) NERC developed proposed Reliability Standard TPL-001-5 (Transmission Operations) following an assessment of single points of failure on protection systems using data collected pursuant to NERC's authority under § 1600 of the Rules of Procedure ("ROP"). Two NERC technical standing committees, with the assistance of NERC staff, analyzed this data and identified the extent of the reliability issue.

(iv) In 2010, NERC identified the need for a task force to address resiliency to geomagnetic disturbance ("GMD") events. Building upon the work of the GMD task force, NERC developed three versions of Reliability Standard TPL-007 (Transmission System Planned Performance for Geomagnetic Disturbance Events)

during the Assessment Period. The TPL-007 Reliability Standard requires planning entities to assess the vulnerability of their systems to severe, 1-in-100 year GMD planning events. Further, NERC began work on a FERC mandatory request for GMD data pursuant to § 1600 of the ROP to improve the availability of GMD data. In 2019, NERC initiated a new task force intended to address resiliency to electromagnetic pulse.

(v) To ensure that supply chain risk management Reliability Standards are properly scoped and implemented effectively, the NERC Board issued a series of resolutions directing NERC to continue working with industry and vendors on supply chain risk issues. The resolutions addressed studying the nature and complexity of supply chain risks, among other activities. In 2018-2019, at the direction of the NERC Board, NERC also prepared a report on cyber security supply chain risks with recommendations for future actions. NERC worked with the Electric Power Research Institute to provide an independent assessment of industry supply chain risks and presented an interim report to the NERC Board in August 2018. The NERC Board received the final report in May 2019. Recognizing the complex and evolving nature of supply chain risks, this final report contains several recommendations for further study (including the study of data collected pursuant to a forthcoming ROP § 1600 data request).

As demonstrated above, Reliability Standards are an important tool for reliability of the BPS; however, the need to address new and emerging risks may require tools outside of Reliability Standards. The Blue Cut Fire event, discussed above, is a prime example of NERC leveraging its various functions and processes to gather and share information in a timely fashion with industry while gradually examining the need for a Reliability Standard. The loss of solar photovoltaic resources during this event and other fault-induced solar photovoltaic resource loss events resulted in the creation of an event report and lessons learned for industry. NERC also posted Alerts in 2017 and 2018 to address this issue. Building upon these event analysis tools, NERC formed a joint Inverter-Based Resource Performance Task Force to develop models and simulations to inform guidelines on recommended practices for inverter based resources connected to the BPS. These Alerts and lessons learned are also informing modifications to the PRC-024 Reliability Standard (Generator Frequency and Voltage Protection Settings).

Guidelines are also important tools, outside of Reliability Standards, available to the ERO to address reliability risks. The objective of the reliability guidelines is to distribute key practices and information on specific issues critical to promote and maintain a highly reliable and secure BPS. Reliability guidelines are not binding norms or parameters to the level that compliance to NERC's Reliability Standards are monitored or enforced. Incorporation of guidelines into industry practices is voluntary. NERC evaluates whether reliability or technical risks require modification to Reliability Standards or development of guidance. NERC will not develop guidelines that conflict with the requirements of a Reliability Standard. Guidelines are used when a reliability risk requires further investigation or when a potential Reliability Standards-based solution needs further vetting prior to initiating the standard development process. NERC will also solicit

information from industry to identify more cost effective solutions outside of developing a Reliability Standard before initiating a standards authorization request.

C. The Electricity Information Sharing and Analysis Center ("E-ISAC") is Securing the BPS through Information Sharing and Analysis

In conjunction with Reliability Standards and electric industry coordination, the ERO Enterprise continues deploying information sharing and analysis as part of a comprehensive approach to securing the grid. During the Assessment Period, NERC enhanced capabilities of the E-ISAC, a division of NERC, which serves as a security communications channel for the electricity industry. It is headed by NERC's Vice President, Chief Security Officer ("CSO") who reports to NERC's President and Chief Executive Officer ("CEO"). The NERC Board oversees the operation of the E-ISAC through, among other things, the NERC Board Technology and Security Committee. The E-ISAC must adapt to the changing threat landscape, technologies, and business processes across the industry. It strives to enhance industry readiness and responses to threats, vulnerabilities, and incidents that could affect the BPS. NERC's biennial GridEx simulation exemplifies the way in which E-ISAC capabilities support the security of the BPS. GridEx allows participants the opportunity to self-assess their emergency response and recovery plans through simulated security exercises featuring stresses on the system. Each exercise builds on lessons learned from prior exercises and real-life scenarios (such as the attack on Ukraine's electricity infrastructure through improper infiltration of the supervisory control and data acquisition system). The E-ISAC also hosts an annual grid security conference to discuss cyber and physical security issues.

The E-ISAC also coordinates with the industry-led Electricity Subsector Coordinating Council ("ESCC"), which fosters the coordination of sector-wide, policy-related activities and initiatives to improve reliability and resilience of the electricity sector. In 2018, the E-ISAC began implementing a long-term strategic plan developed with guidance from the ESCC. The E-ISAC receives strategic oversight and guidance from the ESCC's Member Executive Committee ("MEC"). The MEC is comprised of eleven members appointed by the ESCC, one of which is the NERC CEO. The MEC provides industry leadership and strategic expertise to guide and support the E-ISAC. Beginning in 2019, the E-ISAC developed a set of performance metrics as a tool to help measure the E-ISAC's performance. The E-ISAC expects to review and update these metrics on an annual basis. The metrics measure the E-ISAC's progress against its execution of its long-term strategic plan, and were developed in consultation with the MEC and endorsed by the NERC Board. The E-ISAC provides quarterly metrics reports to the MEC and the NERC Corporate Governance and Human Resources Committee.

NERC has long recognized the importance of promoting robust information sharing between the E-ISAC and electric industry participants to enhance industry's ability to prepare for and respond to cyber and physical security threats, vulnerabilities, and incidents. Because of NERC's responsibilities for the E-ISAC and the development and enforcement of mandatory Reliability Standards, the NERC Board was concerned that electric sector participants may be hesitant to share information with the E-ISAC out of fear that those matters would be referred to the NERC CMEP functions. To address these concerns, in February 2012, the NERC Board adopted a policy to establish a clear separation between the E-ISAC and the CMEP. As revised in March 2013, the NERC Board policy outlines the following principles:

(vi) the E-ISAC and E-ISAC Personnel shall have no responsibilities for the NERC CMEP;

(vii) E-ISAC personnel shall not, directly or indirectly, report or convey information about possible violations of Reliability Standards to the CMEP or CMEP personnel; and

(viii) CMEP personnel shall not, directly or indirectly, obtain or seek to obtain information about possible violations of Reliability Standards from E-ISAC personnel.

In May 2014, NERC management, in consultation with stakeholders, adopted the E-ISAC Code of Conduct to implement the NERC Board policy. The Code of Conduct governs the E-ISAC's relationship with other NERC departments and outlines the parameters within which E-ISAC personnel can share member-provided information outside of the E-ISAC. The Code of Conduct governs all NERC employees, including E-ISAC personnel, at all times. The Code of Conduct sets out broad information sharing restrictions. Subject to limited exceptions, information voluntarily provided to the E-ISAC cannot be shared with any other NERC or Regional Entity personnel. Because of this Code of Conduct, much of the information the E-ISAC receives cannot be used across the ERO to inform the development of Reliability Standards or the CMEP. When the E-ISAC issues public reports that aggregate and anonymize data, however, NERC may use such information to inform its activities in other functions.

In 2014, the E-ISAC, in close coordination with the Department of Energy ("DOE") and the ESCC, assumed the role of program manager in establishing a Cyber Security Risk Information Sharing Program ("CRISP")[10] for electric utilities in October 2014. The CRISP agreements contain strict data handling and protection provisions limiting the ability to share certain CRISP data. After anonymizing CRISP data, however, classified analysis reports are shared with asset owners and operators having the appropriate security clearances and unclassified threat indicators included in the CRISP reports. CRISP data is also available to asset owners and operators with access to the E-ISAC membership portal.[11] Industry participation in CRISP has increased steadily since 2014. While details regarding participation remain confidential, the program has significant participation by investor-owned utilities, as well as a number of large public power utilities and generation and transmission cooperatives. The E-ISAC has also been working with DOE to explore mechanisms to extend the benefits of CRISP to smaller utilities at lower cost. For example, DOE has initiated a pilot program to provide funding to smaller utilities to join CRISP at no cost for three years based on specific criteria.

Throughout the Assessment Period, the E-ISAC continued enhancing its membership portal, including offering more granular security alerts and notifications, tools for industry peer collaboration, and training materials. NERC continues to improve the capability of the membership portal by launching updates to enhance functionality, organization, and security.

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[10] CRISP is a voluntary program to facilitate Real-time, computer-to-computer-data exchange involving potential security threats identified through monitoring participant utility networks.

[11] The E-ISAC portal is the primary means for voluntary information sharing between the E-ISAC and its membership.

D. Strengthening the ERO Enterprise Model through Operational Alignment

In addition to addressing reliability risks during the Assessment Period, the ERO focused on improving operational efficiencies associated with oversight of the Regional Entities to whom NERC has delegated certain authority pursuant to Section 215 of the FPA.[12] During the Assessment Period, NERC consolidated the operations of the ERO Enterprise by terminating the Regional Delegation Agreements of two Regional Entities - Florida Reliability Coordinating Council – Regional Entity Division ("FRCC RE") and Southwest Power Pool – Regional Entity Division ("SPP RE") – and authorizing the transfer of the registered entities in their footprints to SERC and Midwest Reliability Organization ("MRO"). NERC amended the Regional Delegation Agreements for SERC and MRO to reflect the incorporation of the FRCC RE and SPP RE registered entities into their footprints. Through this consolidation, the ERO has completed its transition away from Regional Entities performing registered entity functions.

In the 2014 Performance Assessment, NERC proposed steps to achieving a more unified implementation of the major statutory functions with the Regional Entities. The Commission agreed with this vision and directed NERC to increase consistency and to promote coordination across the ERO Enterprise. To achieve alignment, consistent with the Commission's directive in the 2014 Five Year Order, NERC implemented two important tools: (i) formal oversight and audit of targeted risks associated with functions delegated to Regional Entities; and (ii) the ERO Enterprise Program Alignment Process ("Alignment Process").

[12] 16 U.S.C. § 824o.

NERC initiated a formal oversight program for each of its delegated functions pursuant to which it required every business unit responsible for a delegated function to prepare an oversight plan for the Regional Entities. In each oversight plan, business units outlined the roles and responsibilities of NERC and the Regional Entities and identified performance metrics to evaluate Regional Entities from year to year. NERC requires each business unit to document annual metrics as well as lessons learned in an annual performance report. Through oversight and targeted audits conducted pursuant to Section 1207 and Appendix 4A of the ROP, NERC monitors operational risks that are a priority for the ERO Enterprise. NERC conducts the Appendix 4A targeted audits in close coordination with NERC's Compliance and Certification Committee ("CCC") – the Board-appointed stakeholder committee that directly reports to the NERC Board. The CCC provides support and independent advice on the execution of these oversight programs and monitors NERC's compliance with the ROP for these programs on an ongoing basis.

The Alignment Process operates parallel and complementary to oversight and targeted audits. The Alignment Process is designed to track (identify and capture), triage (classify, analyze, and prioritize), and provide transparency (post and report) on areas where the ERO Enterprise could improve or increase alignment. NERC tracks and publicly posts all identified topics, recommendations and resolutions or mitigation actions on its website. The Alignment Process is an expansion of a "Consistency Reporting Tool" that was developed by the Regional Entities in 2017 and posted on the individual Regional Entity websites to allow stakeholders to identify any inconsistencies across Regional Entities.

To further its efforts to achieve greater efficiency and alignment, NERC launched the ALIGN tool (previously called the CMEP Technology Project). The ALIGN tool will enhance the ERO Enterprise's ability to collect, share and analyze data that is crucial to reliability and security of the BPS. The tool will enhance NERC's ability to leverage the benefits of the ERO Enterprise model by eliminating varying systems and processes for monitoring compliance and establishing a single platform that aligns the business processes of the ERO Enterprise and improves documentation. Over time, the ALIGN tool will also create a single searchable database of CMEP data that can be leveraged to identify risks to reliability and provide additional input to NERC's overall risk mitigation strategies, which would include its ability to assess the need to develop new or modified Reliability Standards. NERC initiated the ALIGN project in 2018 targeting complete implementation of the tool in 2020. NERC also commenced a similar project for its registration function (*see infra* Section IV.C.1), which will accomplish the same effectiveness and efficiency goals. Together, these operational efforts illustrate NERC's actions to address consistency and coordination across the ERO Enterprise.

III. NERC'S ACTIVITIES AND ACCOMPLISHMENTS CONTINUE TO SATISFY THE ERO CERTIFICATION CRITERIA OF 18 C.F.R. § 39.3(b)

When NERC was certified as the ERO for North America, NERC demonstrated that it met the criteria and developed the processes required under 18 C.F.R. § 39.3(b).[13] In this section,

[13] 18 C.F.R. § 39.3(b) provides that the Commission must determine that any entity certified as the ERO achieves the following:

> (1) Has the ability to develop and enforce, subject to § 39.7, Reliability Standards that provide for an adequate level of reliability of the BPS; and
>
> (2) Has established rules that:

NERC highlights new activities and initiatives from the Assessment Period which demonstrate that NERC should continue to serve as the ERO, consistent with the criteria and processes mandated in 18 C.F.R. § 39.3(b).

A. NERC Continues to Advance its Ability to Develop Reliability Standards that Provide for an Adequate Level of Reliability of the BPS

During the Assessment Period, NERC continued to demonstrate its ability to develop Reliability Standards in support of a reliable and more secure grid. NERC addressed gaps in reliability through several Reliability Standards projects, including the following:

(i) to address the physical security of the BES, NERC developed the CIP-014 Reliability Standard which seeks to protect critical transmission stations and substations and their associated primary Control Centers from physical attack that could damage or render such facilities inoperable;

(ii) to address the potential impacts of GMD events on reliable operations, NERC developed the TPL-007 Reliability Standard which uses the latest in scientific and technical understanding to define GMD planning events for entities to use in assessing their vulnerabilities to GMD events. NERC also initiated the GMD Research Work Plan to continue to advance its understanding of this reliability risk and to inform future versions of the standard;

(iii) to address cyber security risks posed by vulnerabilities in the supply chain, NERC developed one new and two revised Reliability Standards to address supply chain risk management for industrial control system hardware, software, and computing and networking services associated with BES operations. In May 2019, NERC

(i) Assure its independence of users, owners and operators of the BPS while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any Electric Reliability Organization committee or subordinate organizational structure;

(ii) Allocate equitably reasonable dues, fees and charges among end users for all activities under this part;

(iii) Provide fair and impartial procedures for enforcement of Reliability Standards through the imposition of penalties in accordance with § 39.7, including limitations on activities, functions, operations, or other appropriate sanctions or penalties;

(iv) Provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing Reliability Standards, and otherwise exercising its duties; and

(v) Provide appropriate steps, after certification by the Commission as the Electric Reliability Organization, to gain recognition in Canada and Mexico.

completed a study further assessing supply chain risks with recommendations for future actions;[14]

(iv) to provide for enhanced information sharing of actual and attempted efforts to compromise the cyber security of the grid, NERC developed Reliability Standard CIP-008-6. This Reliability Standard broadens Requirements for mandatory incident reporting and requires that information be shared with the National Cyber Security and Communications Integration Center, in addition to the currently mandated reporting to the E-ISAC; and

(v) to improve the quality and rigor of planning studies and thereby promote a more reliable BPS, NERC developed proposed Reliability Standard TPL-001-5. This Reliability Standard would require planning entities to study, among other things, the potential impacts of Protection System "single points of failure" on their Systems. NERC identified this risk following an analysis of data collected pursuant to a data request under §1600 of the ROP.

In addition to adopting new Reliability Standards, NERC implemented initiatives to enhance the Reliability Standards development process. First, in response to the Commission's directive in the 2014 Five Year Order to develop and to post more granular assessments of Reliability Standards development, NERC launched a pilot project to track, on a going-forward basis, actual Reliability Standard project completion times as compared to estimated time for completion at the outset of a given project. In the 2014 Five Year Order, FERC noted that information regarding Reliability Standards projects was limited to whether a given project was "urgent" or "non-urgent."[15] The Commission sought information regarding how total time for development reflects the overall complexity of a project.[16] As part of its pilot, NERC designed a Project Tracking Spreadsheet to examine a project's actual completion time, defined as the total time between the first posting and the date of the final ballot. NERC tracks the following features of a Reliability Standard project as indicators of the complexity of a project:

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[14] *NERC Cyber Security Supply Chain Risks: Staff Report and Recommended Actions*, Docket No. RM17-13-000 (May 28, 2019).

[15] 2014 Five Year Order at P 64.

[16] *Id*.

(i) project priority (1 - 3, with 1 being the highest priority) consistent with the annual Reliability Standards Development Plan;

(ii) number of directives that are addressed by the project;

(iii) number of recommendations from FERC orders that do not rise to the level of a directive, but that are addressed by the project; and

(iv) number of other Reliability Standards affected by the project (i.e., those requiring retirement or amendment).

NERC updates the tracker monthly using inputs from Reliability Standard developers as well as Project Management and Oversight Subcommittee liaisons to the Standards Committees.

Second, NERC launched initiatives to improve Reliability Standards so that risks to the BPS are addressed in a more effective and efficient manner. Since its certification as the ERO, NERC has addressed the Commission's standard modification directives from Order No. 693 and subsequent orders and remaining gaps within Reliability Standards, as discussed above. NERC has shifted its focus towards refining the existing Reliability Standards to become more effective and efficient and addressing any newly identified reliability risks. This builds upon efforts from the previous assessment period, including the Independent Experts Review Project[17] and Project 2013-02 Paragraph 81.[18]

NERC's Standard Processes Manual ("SPM") requires the periodic review of each Reliability Standard to determine whether it should be reaffirmed, revised, or withdrawn.[19] In

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[17] The purpose of this project was to conduct an independent review and evaluation of the body of non-CIP Reliability Standards to recommend areas for improvements, identify reliability gaps, and recommend retirements and consolidations of standards. The final report, titled *Standards Independent Experts Review Project: an Independent Review by industry Experts* (June 2013), is available on NERC's website at: https://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf.

[18] The purpose of this project was to propose the retirement of Reliability Standard requirements that provided little protection to the reliable operation of the BES, were redundant, or were unnecessary, in accordance with FERC's March 15, 2012 Order on NERC's Find, Fix, and Track process. *See N. Am. Elec. Reliability Corp.*, 138 FERC ¶ 61,193, at P 81 (2012).

[19] SPM § 13.0.

2016, NERC began using a tool to support this periodic review process by grading all Reliability Standards that are currently enforceable or subject to enforcement for one year. Reliability Standards were graded through an open and inclusive stakeholder process and final grades were included in the Reliability Standards Development Plan filed yearly with the Commission on an informational basis.

NERC also initiated the Standards Efficiency Review in 2017. The goal of this project is to retire or modify unnecessary or redundant Reliability Standard Requirements without jeopardizing the reliability of the BPS. The first phase of the project focused on Operations and Planning Reliability Standards. At the end of this phase, the Standards Efficiency Review team recommended retiring a number of Reliability Standards Requirements as duplicative of other Requirements or as administrative in nature. In 2018, NERC initiated Project 2018-03 Standards Efficiency Review Retirements to implement the retirement recommendations.[20] During the second phase of the project, NERC is leading two efforts. First, NERC is evaluating how to retire or modify unnecessary or redundant Critical Infrastructure Protection ("CIP") Reliability Standards Requirements, as it previously did with Operations and Planning Reliability Standards. Second, NERC is evaluating the following six concepts as possible projects to improve the body of Reliability Standards – both Operations and Planning and CIP Reliability Standards:

(i) Concept 1 – Evidence Retention – NERC will examine: (i) data retention requirements to ensure that the burden of producing records necessary to demonstrate compliance is commensurate with the risk to the reliability of the BPS; and (ii) potential uniform tools and applications to standardize evidence retention requirements;

(ii) Concept 2 – Prototype Reliability Standards – NERC will examine the contents of a risk-based standards template to guide standard drafting teams in developing standards that address a risk objective without being overly prescriptive;

[20] More information about Project 2018-03 is available at https://www.nerc.com/pa/Stand/Pages/Project-2018-03-Standards-Efficiency-Review-Retirements.aspx.

(iii) Concept 3 – Relationship between Guidance and Standards – NERC will develop a repeatable process whereby the ERO determines when a risk to the BPS requires development of a Reliability Guideline or a Reliability Standard;

(iv) Concept 4 – Training Requirements – NERC will evaluate whether to consolidate all training requirements in the body of Reliability Standards into the Personnel Performance, Training and Qualifications ("PER") family of standards;

(v) Concept 5 – Data Exchange Requirements – NERC will evaluate ways in which to consolidate information / data submittals dispersed across various family of standards; and

(vi) Concept 6 – Competency-based Requirements – NERC will evaluate how best to address competency-based requirements in the body of standards.

B. NERC Coordinates Budget and Strategic Planning across the ERO Enterprise

During the Assessment Period, NERC sought to align NERC and Regional Entity annual business plans and budgets ("BP&Bs"), ERO Enterprise risks, and the ERO Enterprise strategic planning process. The RISC biennial report informs the following strategic and budget planning documents:

(i) ERO Enterprise Long-Term Strategy – The long-term strategy addresses the ERO Enterprise's approach to addressing risks for a five to seven year time frame.

(ii) ERO Enterprise Operating Plan – Guided by the long-term strategy, this plan identifies the ERO Enterprise's vision, mission, core principals, and goals, and provides a list of key contributing activities to inform a rolling operational planning horizon. NERC flags any activities that are recommendations from the RISC report.

(iii) ERO Enterprise BP&Bs – The BP&Bs set the specific annual activities, resources, and resource allocation in support of the goals and objectives in the operating plan. BP&Bs are prepared, reviewed, and approved annually for NERC and each of the Regional Entities, and NERC reviews the Regional Entities' BP&Bs for alignment with the ERO Enterprise Operating Plan.

(iv) ERO Enterprise Metrics – The metrics provide performance benchmarks for the ERO activities outlined in the BP&B.

C. NERC Continues to Enhance its Procedures for Compliance and Enforcement

The ERO Enterprise strives to serve as an objective and fair enforcement authority that promotes a culture of reliability excellence through risk-based registration, certification, compliance monitoring, enforcement and mitigation. During the Assessment Period, NERC enhanced its CMEP by: (i) researching and identifying trends in the incidence of noncompliance; (ii) maintaining the transparency of its dispositions of noncompliance; and (iii) increasing procedural efficiencies in coordination with the Regional Entities. NERC ends this Assessment Period with a structure in place, through the Alignment Process, to collect, review, resolve, and communicate discrepancies in practices across the ERO Enterprise. NERC tracks identified discrepancies as well as their associated recommendations or resolutions.

1. Trends in Noncompliance

The ERO Enterprise continues to implement a risk-based approach focusing on registered entity-specific risks and serious noncompliance. NERC observed two notable trends during the Assessment Period: (i) reduced repeat moderate and severe risk violations; and (ii) continued progress in mitigating the ERO's older caseload of noncompliance.

To gauge the effectiveness of the risk-based CMEP in deterring and mitigating higher risk violations during the Assessment Period, the Commission directed NERC to examine the incidence of repeat noncompliance.[21] To measure this, NERC reviewed moderate and serious risk violations for registered entities with the following compliance histories: (i) no prior compliance history; (ii) compliance history involving dissimilar conduct; and (iii) compliance history involving similar conduct. NERC notes the following:

[21] 2014 Five Year Order at P 39.

(i) NERC reviewed all noncompliance filed between 2012 and 2018 and found an overall downward trend of moderate or serious risk determinations for entities with prior noncompliance with similar conduct over the past five years;

(ii) In 2016, NERC filed 111 violations with moderate or serious risk determinations for entities with prior noncompliance with similar conduct.

(iii) In 2017, there were 48 filed violations for entities with prior noncompliance with similar conduct.

(iv) In 2018, there were 22 filed violations for entities with prior noncompliance with similar conduct.

NERC expects some level of noncompliance with similar underlying conduct to persist. The downward trend in repeat moderate and severe risk violations is noted in the **Figure [1]**[22] below:

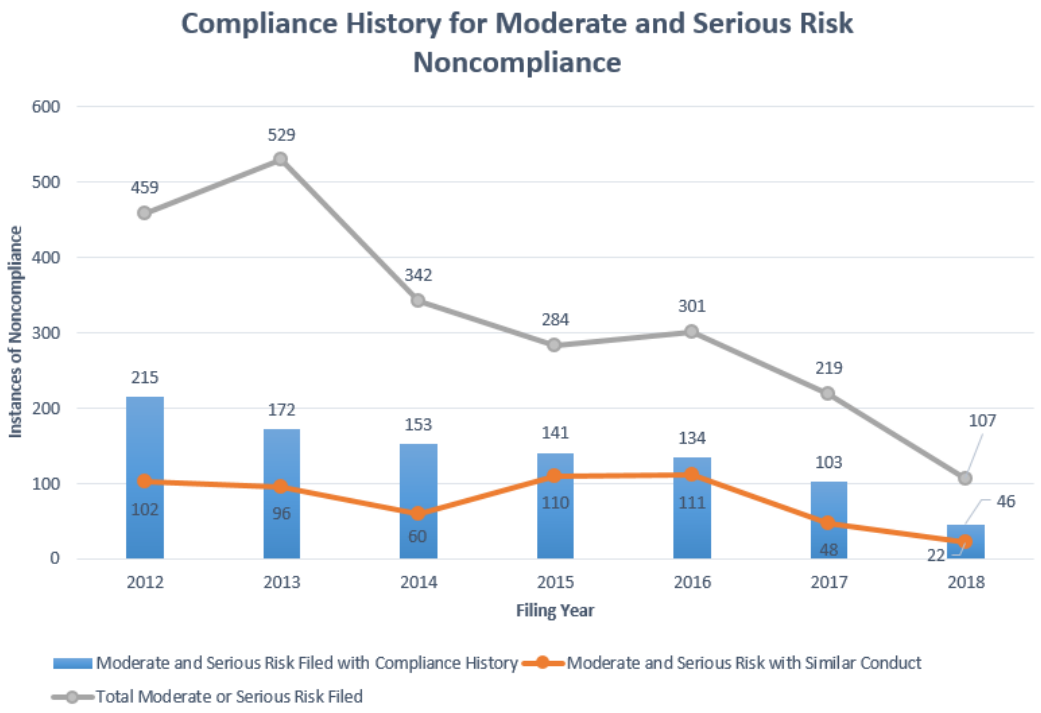


Figure 1 - Instances of Moderate and Serious Risk Noncompliance Filed with Compliance History or Similar Conduct, 2012-2018

[22] Unless otherwise noted, all figures and tables in the filing include SPP RE data.

As shown in **Figure [2]** below, there has also been a general decrease in the number of serious risk violations across the ERO Enterprise during the Assessment Period. Serious risk violations historically have comprised only a small percentage of the total:

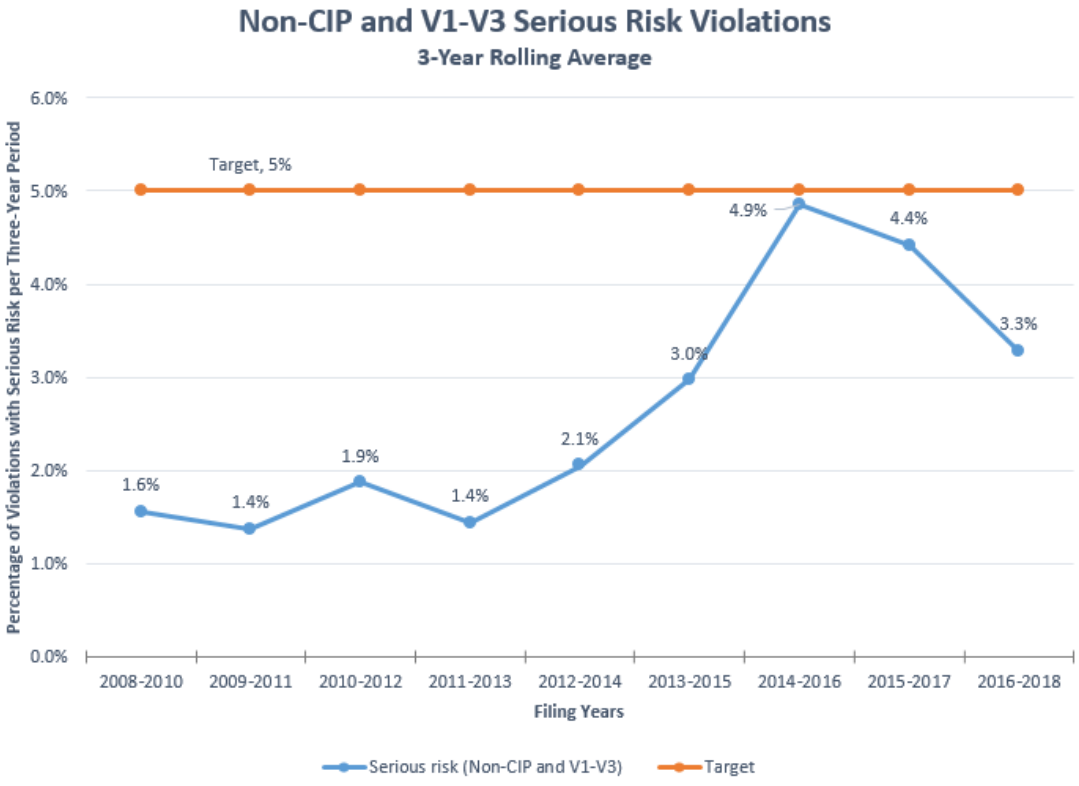


Figure - 2 Three-Year Rolling Average of Serious Risk Violations as a Percentage of all Filed Violations, by Filing Year (Non CIP and CIP Versions V1-V3)



Figure 3 - Three-Year Rolling Average of Serious Risk Violations as a Percentage of all Filed Violations, by Filing Year (CIP Only)

As shown in the preceding two figures, serious risk violations comprise a small percentage of the total noncompliance during the Assessment Period. NERC filed the highest number of serious risk violations as a percentage of total violations in 2016. Since that time, the percentage of serious risk violations as a percentage of all filed noncompliance has fallen to under NERC's self-determined target of five percent.

The ERO Enterprise conducted focused reviews in 2017 and 2018 to identify whether deficiencies in mitigation contributed to noncompliance and to identify potential methods of further reducing repeat noncompliance. To provide NERC with better visibility and a wider perspective of the issue, NERC now tracks and reports on compliance history on a quarterly basis.

2. Transparency in Compliance and Enforcement

Consistent with the Commission's expectations in the 2014 Five Year Order, NERC continues to maintain transparency in its disposition of noncompliance.[23] In addition to its quarterly reports on all matters associated with CMEP activities, public webinars and other opportunities to exchange information about its programs, on its website, NERC publicly posts dispositioned noncompliance, whether through a Full Notice of Penalty, Spreadsheet Notice of Penalty, Find, Fix, Track, and Report ("FFT"), or Compliance Exception. In parallel path, NERC takes steps to safeguard confidential information and to ensure the accuracy and completeness of CMEP data. NERC enhanced its internal policies by: (i) segregating duties for the publication of content to NERC's public website from duties to develop materials for publication; and (ii) developing procedures delineating roles and responsibilities in the event of inadvertent disclosure.

3. Enhancing Procedural Efficiencies in the CMEP

As the ERO Enterprise matures in its risk-based approach for CMEP, it is important to have a computer system that accurately manages and analyzes data and other information handled on a daily basis. Over the course of ALIGN's development, NERC worked with a stakeholder group to collect registered entity perspectives and feedback. The tool is expected to increase efficiencies by standardizing processes (including forms and interfaces) across the ERO Enterprise, to improve documentation, and to support ERO Enterprise-wide sharing and analysis of CMEP information. ALIGN will have a single, common portal for registered entities, enabling consistency of experience. NERC expects to eliminate delays and manual communications with the advent of Real-time access to CMEP information. In addition to the procedural efficiencies, the CMEP tool is projected to provide cost-savings for the ERO Enterprise. By the end of the

[23] 2014 Five Year Order at P 72.

Assessment Period, NERC completed more than 50 percent of its business process harmonization activities for the anticipated launch of ALIGN. NERC expects to launch ALIGN through three releases ending in 2020 and resulting in a comprehensive, consistent, and efficient CMEP platform.

NERC also incorporated a consolidated hearing process into the ROP to increase efficiencies, to enhance consistency and to streamline costs in the ERO Enterprise CMEP hearing process. The process allows a Regional Entity to opt-in to a centralized hearing process whereby NERC conducts a contested case hearing in an enforcement dispute. The consolidated process still allows the Regional Entity from whom the dispute originates to appoint up to two members of what is typically a five-member Hearing Body. This process is optional to the Regional Entities. As of May 2019, all Regional Entities except Texas RE have opted to participate in the consolidated hearing process.

Finally, in late 2015, the NERC Board accepted and endorsed the recommendations of the Compliance Guidance policy, which includes Implementation Guidance and CMEP Practice Guides.[24] Pre-Qualified Organizations or Standards Drafting Teams may develop Implementation Guidance providing industry-vetted examples and approaches to illustrate how registered entities could comply with a Reliability Standard. Once submitted to NERC, Implementation Guidance is reviewed for endorsement. The ERO Enterprise also develops CMEP Practice Guides which address how ERO Enterprise CMEP staff execute compliance monitoring and enforcement activities. NERC publishes the complete list of ERO Enterprise endorsed Implementation Guidance as well as CMEP Practice Guides on its website.[25]

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[24] *See* https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Agenda_Package_November_2015_v3a.pdf.

[25] *See* https://www.nerc.com/pa/comp/guidance/Pages/default.aspx.

D. NERC Continues to Maintain Rules to Ensure Due Process, Openness and Balance of Interests in Developing Reliability Standards

NERC continues to maintain rules ensuring due process, openness, and balance of interests in developing Reliability Standards and otherwise exercising its duties. NERC continues to maintain its status as an American National Standards Institute ("ANSI") - accredited standards developer in accordance with the policies and procedures of that organization.

During the Assessment Period, NERC revised its Standard Processes Manual.[26] The revised Standard Processes Manual improves the processes for conducting any necessary field tests for new and revised Reliability Standards, developing interpretations of Reliability Standards, and posting supporting technical documents to approved Reliability Standards. It also contains a number of clarifications and updates throughout. Additionally, in March 2018, the Commission approved revisions to Appendix 3D to the ROP - Registered Ballot Body Criteria - to help ensure that the votes of Independent System Operators and Regional Transmission Organizations are appropriately represented in segment 2 of the NERC Registered Ballot Body for voting on Reliability Standards.[27]

E. NERC Continues Gaining Recognition in Canada and Mexico

The North American BPS spans 10 sovereign jurisdictions across three countries. Dedicated efforts by NERC and Canadian and Mexican partners over the past several years continue to move the reliability regulatory framework toward a high level of consistency across jurisdictional boundaries.

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[26] *Petition of the North American Electric Reliability Corporation for Approval of Proposed Revisions to the Standard Processes Manual, Appendix 3A to the NERC Rules of Procedure,* Docket No. RR19-2-000 (filed Nov. 19, 2018).

[27] *N. Am. Elec. Reliability Corp.*, Docket No. RR18-1-000 (unpublished letter order).

As some of the original proponents for an international ERO, Canadian stakeholders are committed to the 2005 *Principles for an Electric Reliability Organization That Can Function on an International Basis* ("Bilateral Principles"). During the Assessment Period, the ERO saw continued Canadian dedication to a consistent, continent-wide regulatory framework for reliability. Below is a table showing that compliance monitoring arrangements in place between the ERO and all Canadian provinces and showing the parties and dates of all currently effective legislation or agreements.

	MOU Parties	Year Signed
BC	NERC+WECC+BC Utilities Commission	2018
AB	NERC+WECC+AESO; WECC+MSA	2010
SK	NERC+MRO+SaskPower	2015
MB	NERC+MRO+MB Government NERC+MRO+Manitoba Hydro	2012 2018
ON	NERC+NPCC+IESO NERC+OEB	2006 2006
QC	NERC+NPCC+Régie	2009, 2014
NS	NERC+NPCC+NS Power; NERC+NSUARB	2006
NB	NERC+NPCC+NB Energy and Utilities Board	2016
NEB	NERC+NEB	2007

In addition to Canada, Mexico is increasing its interaction with the ERO Enterprise. In 2015, Mexico began implementing comprehensive energy reforms adopted in 2013 and 2014, thereby prompting greater Mexican participation in the ERO Enterprise. Mexico adopted its first comprehensive mandatory reliability framework and garnered the support and resources of the

ERO Enterprise to implement its historic energy reforms. To formalize its relationship with NERC as a resource and expert on electric reliability, NERC, Centro Nacional de Control de Energia ("CENACE"), and the Comisión Reguladora de Energía [28] executed a memorandum of understanding ("MOU") in 2016. Through the MOU, the parties created a senior management Steering Group to oversee activity under the MOU and to finalize the funding framework for activities under the MOU. The parties also committed to exploring opportunities for formal Mexican participation in the ERO. Pursuant to this MOU, NERC conducted a Cyber Risk Preparedness Assessment on Mexican utilities in 2016. The purpose of the assessment was to ensure that CENACE operations were consistent with Reliability Coordinator, Balancing Authority and/or Transmission Operator-type Reliability Standards, inclusive of CIP Reliability Standards.

IV. EVALUATING REGIONAL ENTITY PERFORMANCE

Commission regulations require that each assessment of the ERO's performance include "an evaluation of the effectiveness of each Regional Entity, recommendations by the Electric Reliability Organization, users, owners, and operators of the BPS, and other interested parties for improvement of the Regional Entity's performance of delegated functions, and the Regional Entity's response to such evaluation and recommendations." [29] Through oversight and audit conducted pursuant to Section 1207 and Appendix 4A of the ROP, NERC evaluates Regional Entity performance and compliance with the ROP, Commission directives, the Regional Delegation Agreements, NERC policies or procedures as well as guidance and directions issued

[28] CENACE is a public decentralized body in Mexico that exercises the operative control of the power system. Comisión Reguladora de Energía is an agency of CENACE, as a coordinated energy regulator of Mexico.

[29] 18 C.F.R. § 39.3.

by the NERC Board.[30] During the Assessment Period, NERC launched a formal oversight program pursuant to which NERC identified oversight monitoring activities, as well as performance metrics for the Regional Entities.[31] Each year, these monitoring activities shift focus to address new risks and to reflect the results of Regional Entity performance from the prior year. NERC documents Regional Entities' performance, as measured against the oversight plan metrics, in annual performance reports shared with the Regional Entities and NERC senior management. Using Regional Entity and senior management feedback, NERC updates oversight plans to reflect any identified areas of focus or risk.

As indicated in NERC's 2015 informational filing to the Commission, NERC developed a staggered schedule to develop oversight plans for each function. The first set of oversight plans developed were implemented in 2017 and NERC issued performance reports in the first quarter of 2018. Regional Entities reviewed the performance reports and provided feedback to NERC, including proposals to mitigate any areas of improvement identified by NERC business units. This feedback loop resulted in revised oversight plans for the 2018 calendar year. NERC repeated the process in 2018 with performance reports issued in 2019 for 2018 activities.

NERC leverages the oversight plan performance reports and results of other Regional Entity oversight activities[32] to identify risk areas warranting targeted audits conducted in accordance with generally accepted auditing principles. During the Assessment Period, NERC performed targeted audits of the following areas:

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30 *See Pro Forma* NERC Regional Delegation Agreement, Section 8(f).

31 In the 2014 Five Year Order, the Commission directed NERC "to continue developing performance metrics that measure consistency, coordination, and efficiency between and among NERC and the Regional Entities in order to achieve predictable, timely, and consistent results across the ERO Enterprise." 2014 Five Year Order at P 73.

32 In addition to oversight plan performance reports, NERC examines the following during its audit scoping process: (i) annual ERO Enterprise risk assessments; (ii) Regional Entity self-certifications; (iii) targeted reviews of different areas; and (iv) feedback from the NERC Board.

(i) confidentiality and conflict of interest;

(ii) event analysis;

(iii) compliance monitoring competency evaluation guide; and

(iv) Section 215 accounting.

NERC functions also reflected feedback from these targeted audits in their revised oversight plans for the following calendar year. Below, NERC outlines its findings and recommendations from its Regional Entity oversight.

A. Reliability Standards

While each Regional Entity may propose regional Reliability Standards to the ERO,[33] the ERO Enterprise has made a concerted effort to focus efforts on supporting the development of continent-wide Reliability Standards and using Variances,[34] where possible, to address necessary differences while achieving a similar or greater level of reliability. In support of this shift, the Regional Entities are engaged in continual review of their standard development procedures for opportunities to align them with NERC's standard development procedures while continuing to maintain individual FERC-approved efficient processes. The Regional Entities also initiated projects to conduct periodic reviews of regional Reliability Standards and Interconnection-wide Variances and to revise or retire existing regional Reliability Standards. No new regional Reliability Standards were proposed during the Assessment Period. As of December 31, 2018, 12

[33] *See* Section 215(d) of the FPA, Section 39.8 of the Commission's regulations, and the Regional Delegation Agreements.

[34] A "Variance" is defined in Appendix 2 to the NERC ROP as "an aspect or element of a Reliability Standard that applies only within a particular Regional Entity or group of Regional Entities, or to a particular entity or class of entities. A Variance allows an alternative approach to meeting the same reliability objective as the Reliability Standard, and is typically necessitated by a physical difference. A Variance is embodied within a Reliability Standard and as such, if adopted by NERC and approved by the Applicable Governmental Authority(ies), shall be enforced within the applicable Regional Entity or Regional Entities pursuant to delegated authorities or to procedures prescribed by the Applicable Governmental Authority."

regional Reliability Standards remained in effect. Out of these 12 regional Reliability Standards, two have been subsequently approved for retirement.

The following table provides a summary of Regional Entity standard development activity requiring NERC action through December 31, 2018, with dates of Commission approval (where applicable):

Regional Entity	**Standard Activity**
MRO	Revisions to Regional Reliability Standards Process Manual, RR16-3-000 (approved 5/6/2016)
NPCC	Revisions to Regional Reliability Standards Development Procedure, RR14-7-000 (approved 12/23/2014) Retirement of PRC-002-NPCC-01, RD16-8-000 (approved 8/16/2016) PRC-006-3 (revised Variance for the Quebec Interconnection), (filed for information with the Commission on September 5, 2017)
RF	BAL-502-RF-03, RD17-8-000 (approved 10/16/2017)
SERC	Revisions to Regional Reliability Standard Development Procedure, RR18-2-000 (approved 3/31/2018) PRC-006-SERC-02, RD17-9-000 (approved 10/16/2017)
Texas RE	Revisions to Regional Reliability Standards Development Process, RR17-3-000 (approved 5/30/2017) Retirement of IRO-006-TRE-1, RD19-2-000 (approved 1/29/2019)
WECC	Revisions to Reliability Standards Development Procedures: - RR14-8-000, (approved 12/23/2014) - RR17-5-000 (approved 10/27/2017) BAL-002-WECC-2a, RD17-3-000 (approved 1/24/2017) BAL-004-WECC-3, RD18-2-000 (approved 5/30/2018) FAC-501-WECC-2, RD18-5-000 (approved 5/30/2018) IRO-006-WECC-3, RD19-4-000 (approved 5/10/2019) VAR-001-5 (revisions to VAR-001 WECC Variance), RD18-8-000 (approved 10/15/2018) VAR-002-WECC-2, RD15-1-000 (approved 3/3/2015) VAR-501-WECC-2, RD15-1-000 (approved 3/3/2015)

	VAR-501-WECC-3, RD17-5-000 (approved 4/28/2017) VAR-501-WECC-3.1 (errata), RD17-7-000 (approved 9/26/2017) **Retirements** Retirement of PRC-004-WECC-2, RD18-3-000 (approved 3/28/2019) Retirement of TOP-007-WECC-1a, RD16-10-000 (approved 5/10/2017) Retirement of VAR-002-WECC-2, RD18-1-000 (approved 9/5/2018)

B. Compliance Monitoring and Enforcement Program

In this section, NERC describes the oversight activities performed pursuant to the CMEP oversight plans and provides a summary of the results of NERC's oversight during the Assessment Period.

1. Compliance Monitoring

One of the most significant changes to compliance monitoring over the Assessment Period was the implementation of a risk-based approach. The ERO found that it is not practical, effective, or sustainable for the ERO Enterprise to monitor all compliance issues to the same degree or to treat all noncompliance in the same manner. Compliance monitoring and enforcement must be "right-sized" based on a number of considerations, including risk factors and registered entity management practices related to the detection, assessment, mitigation, and reporting of noncompliance. A risk-based approach is necessary for a proper allocation of resources. It also encourages registered entities to enhance internal controls, including those focused on the self-identification of noncompliance. This shift resulted in compliance changing from using a one-size-fits-all actively monitored list of NERC Reliability Standards to focusing on the risks each registered entity posed to the reliability of the BPS.

During the prior assessment period, NERC's multi-year Reliability Assurance Initiative resulted in the development of the ERO Enterprise Risk-Based Compliance Monitoring

Framework ("Framework").[35] In this Framework, NERC focused on identifying, prioritizing, and addressing risks to the BPS, which enables each Compliance Enforcement Authority ("CEA") to focus resources where they are most needed and likely to be the most effective. The first step of the Framework is the identification and prioritization of ERO Enterprise-wide risks. Through the review of the ERO Enterprise-wide risks, the ERO develops an annual compilation of Risk Elements. NERC documents the Risk Elements in the ERO Compliance Monitoring and Enforcement Program Implementation Plan ("CMEP IP").

The CMEP IP contains the ERO Enterprise Risk Elements, which provide guidance to Regional Entities in the preparation of their Regional Entity IPs and regional risks tied to individual registered entities within their footprints. Although the CMEP IP identifies NERC Reliability Standards and Requirements to be considered for focused compliance monitoring, the ERO Enterprise recognizes that Regional Entities will develop a focused list of NERC Reliability Standards and Requirements specific to the risks posed by a registered entity. The CEA outlines this approach in a registered entity-specific Compliance Oversight Plans ("COPs").

A COP reflects the CEA's assessment of a registered entity's inherent risk as well as the risk mitigation activities conducted by the registered entity, such as its internal controls. The COP determines the interval of monitoring, the depth of testing (i.e., a list of NERC Reliability Standards and requirements), and the types of CMEP tools used to engage a registered entity (i.e., audit, spot check or self-certification). The COP is dynamic and requires updating from time to time. CEAs use the COP to tailor CMEP activities based on identified registered entity-specific risks.

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[35] *See Overview of the ERO Enterprise's Risk-Based Compliance Monitoring and Enforcement Program* (Sept. 2014), https://www.nerc.com/pa/comp/Reliability Assurance Initiative/Overview of the ERO Enterprise%E2%80%99s Risk-Based CMEP.pdf.

When developing registered entity-specific COPs, Regional Entities consider local risks and specific circumstances associated with individual registered entities. The COP also takes into account the unique compliance history of each registered entity, along with both the timing of and the results of any prior compliance monitoring, when determining which compliance monitoring tools will be used for future monitoring for each registered entity. A CEA may revise a COP if a registered entity experiences significant changes, new compliance responsibilities, or faces new reliability risks. As a result, the scope of monitoring of a particular registered entity in a COP may include more, fewer, or different Reliability Standards than those outlined in the CMEP IP. The determination of the appropriate CMEP tools may be adjusted as needed within a given implementation year. **Figure [4]** below shows the various inputs for the development of a COP for a given registered entity.

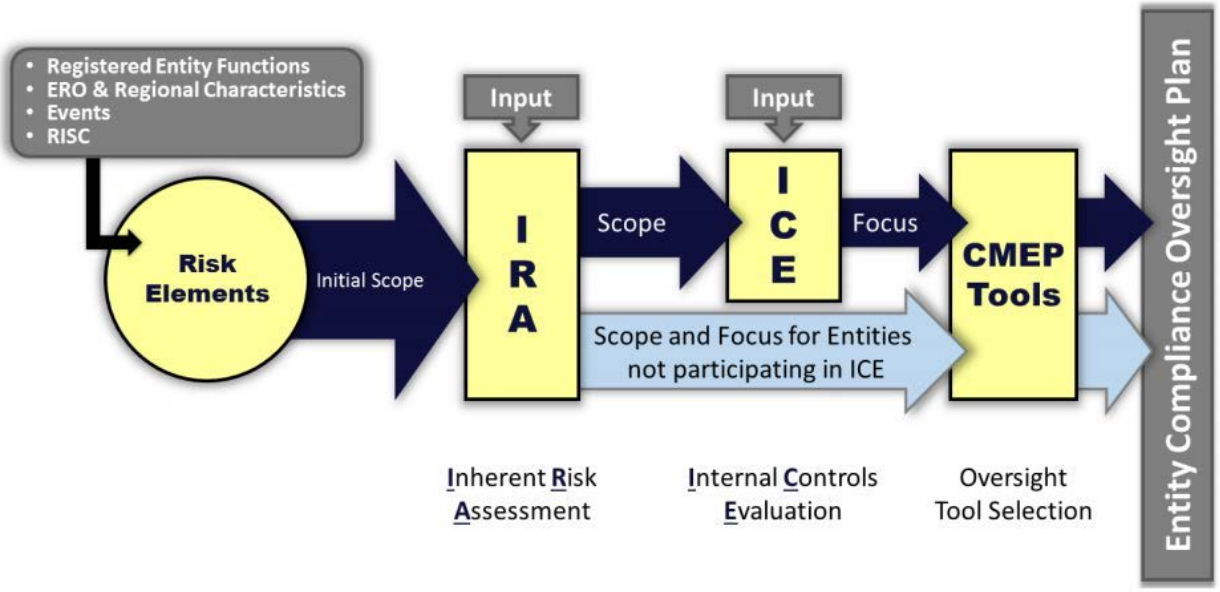


Figure 4 - Inputs for the Development of a COP

a. Risk Elements

NERC and the Regional Entities are responsible for identifying Risk Elements that reflect emerging and impactful risks to the BPS as well as other ERO-wide and Regional Entity-specific risks. NERC leads the effort to identify Risk Elements using inputs from compliance findings, event analysis data, and the expert judgment of NERC and Regional Entities, committees, and subcommittees (e.g., NERC Reliability Issues Steering Committee). NERC lists the Risk Elements in the annual CMEP IP. NERC also identifies Reliability Standard requirements correlated with the identified Risk Elements to prioritize compliance monitoring efforts for a given registered entity.

In the table below, NERC shows the change in Risk Elements during the Assessment Period. The change in Risk Elements from the early years of this Assessment Period to the present reflect a maturation of the risk-based approach to compliance monitoring. The most recent Risk Elements focus on discrete issues that NERC encourages the Regional Entities and industry to

prioritize for the upcoming year. NERC expects the Regional Entities to also develop Risk Elements specific to their footprints to further inform their compliance monitoring activities.

2015	2016 - 2018	2019
Cyber security	Critical Infrastructure Protection	Improper Management of Employee and Insider Access
Extreme Physical Events	Extreme Physical Events	Insufficient Long-Term Planning Due to Inadequate Models
Infrastructure Maintenance	Maintenance and Management of BPS Assets	Insufficient Operational Planning Due to Inadequate Models
Monitoring and Situational Awareness	Monitoring and Situational Awareness	Spare Equipment with Extended Lead Time
Protection System Misoperations / Uncoordinated Protection Systems	Protection System Failures	Improper Determination of Misoperations
Long-Term Planning and System Analysis	Event Response / Recovery / Planning and System Analysis	Improper determination of Misoperations / Inhibited Ability to Ride through Events
Human Error	Human Performance	Gaps in Program Execution
Workforce Capability		

b. Inherent Risk Assessments and Internal Controls

In order to successfully implement risk-based CMEP, the ERO Enterprise refined its understanding of the risks each registered entity poses to the reliability of the BPS. During the

Assessment Period, the Regional Entities developed common risk factors and conducted inherent risk assessments ("IRAs") for registered entities. The common risk factors are quantitative thresholds for various operational features. By developing these common risk factors, the ERO Enterprise could align its approach for conducting IRAs and consistently identifying areas of focus (i.e., specific lists of NERC Reliability Standards) for compliance monitoring activities. Upon completing an IRA, a CEA knows the unique characteristics of a registered entity and its inherent risks to the reliability of the BPS. The CEA can also refine its evaluation of which risk areas should be included in compliance monitoring activities. The CEA accomplishes this by reviewing the registered entity's performance history (i.e., compliance history, event analysis trends, etc.) to understand how an entity is using internal controls to manage compliance and to mitigate risks.

c. NERC's Evaluation of Regional Entity Performance of the CMEP

In the following section, NERC discusses the performance metrics for the Regional Entities during the Assessment Period.

(1) Development of COPs

By the end of the Assessment Period, all Regional Entities implemented processes (i.e., IRA completion) under the risk-based Framework described above. All Regional Entities are using common ERO Enterprise risk factors to develop IRAs and to inform COPs. NERC determined that all the Regional Entities are using their knowledge of a registered entity's inherent risk and performance risk in identifying which monitoring tool to apply, the scope of monitoring engagements, and selecting Reliability Standards to examine. In **Figure [5]** below, NERC compares the number of registered entities to the number of initial IRAs completed by each Regional Entity. By 2018, the Regional Entities completed 1,314 IRAs for 1,488 registered

entities. All Regional Entities completed IRAs for Reliability Coordinators, Balancing Authorities, and Transmission Operators in 2018.

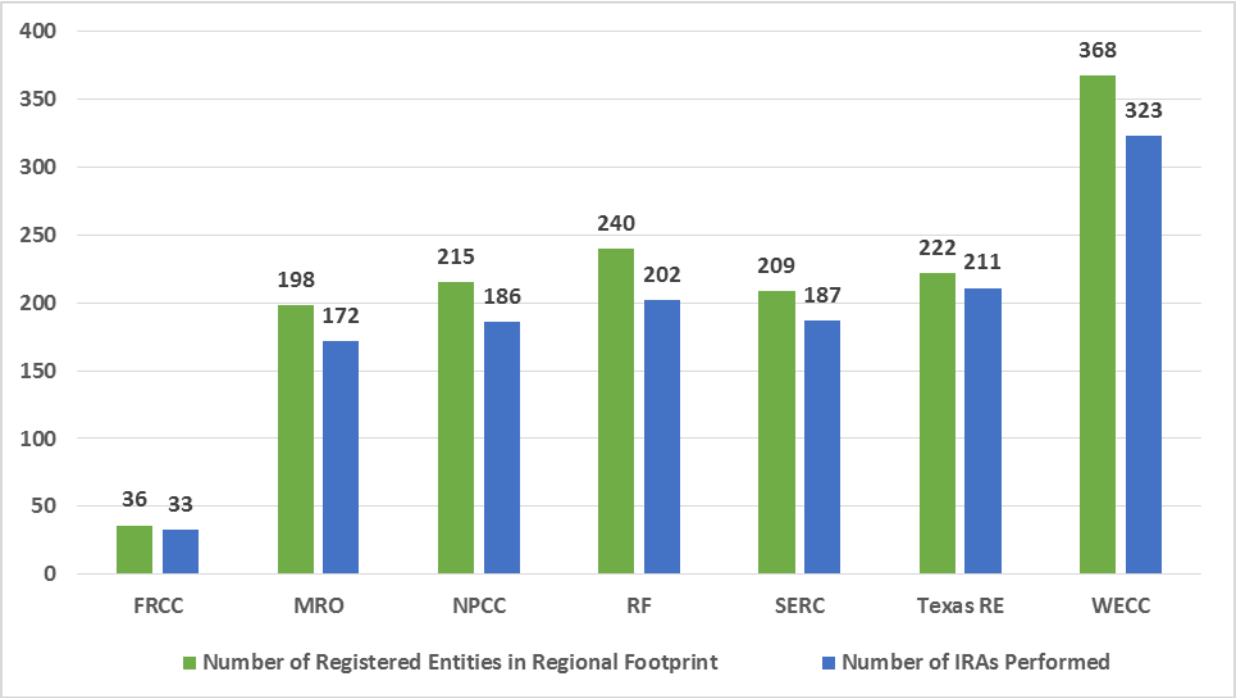


Figure 5 - Number of IRAs Completed by Each Regional Entity

Additionally, NERC and the Regional Entities developed ERO Enterprise-approved templates for their compliance monitoring activities. For example, as of 2017, all Regional Entities use the IRA Summary Reports, Audit Notification Letters, and Audit and Spot Check Reports, as well as templates for these activities occurring in the Coordinated Oversight Program for multi-region registered entities ("MRREs").

While the ERO successfully launched the COP development process during the Assessment Period, there are several ERO Enterprise-wide opportunities to enhance the COP development process. These opportunities include enhancing Regional Entity documentation for: (i) risk and monitoring decisions in COP development; and (ii) decisions around effectiveness for internal control reviews, particularly assessment of registered entity evidence, registered entity

internal control design and implementation. NERC also found that there is an opportunity to improve alignment of Regional Entity CMEP IPs, specifically around the development and use of Regional Risk Assessments and Regional Risk Elements. Moving forward, NERC will determine needs for guidance and training around the level of detail needed to document professional judgment and technical justifications for IRA and COP results.

(2) Audit Documentation

NERC notes that there is an overall opportunity for the Regional Entities to strengthen documentation processes around COP and final audit scope determinations, to ensure documentation is complete and contains sufficient detail to support significant judgments and conclusions. NERC identified certain gaps in documentation that made it difficult to understand final COP decisions around risk areas.

(3) Coordinated Oversight Program

NERC has a Coordinated Oversight Program designed to increase efficiency in the compliance monitoring and enforcement activities forMRREs. The program is voluntary and a registered entity operating in or owning assets in two or more Regional Entity jurisdictions with one or more NERC Compliance Registry identification numbers is a potential candidate for inclusion in the program. A key area of improvement for the Coordinated Oversight Program is increasing regional coordination through refining IRAs, data submittals, and self-report processes. NERC expects that the ALIGN tool will address several of these issues. NERC also identified ERO Enterprise opportunities to improve coordination between lead Regional Entities and affected Regional Entities in developing final compliance monitoring decisions for MRREs in the program.

During the Assessment Period, the ERO Enterprise published an ERO Enterprise Guide for the Coordinated Oversight Program. In this guide, NERC provides details to participating and

interested entities related to general roles and responsibilities, program applicability, and expectations for coordination of various activities. During the Assessment Period, the ERO Enterprise granted 49 MRREs entry into the Coordinated Oversight Program. Due to recent consolidation of a large MRRE group into a single NERC Compliance Registry identification number, the number of registered entities participating in the program decreased from 231 in 2017 to 197 in 2018. **Figure [6]** below shows the distribution of MRREs under coordinated oversight by Lead Regional Entity ("LRE") as of the end of the third quarter of 2018.

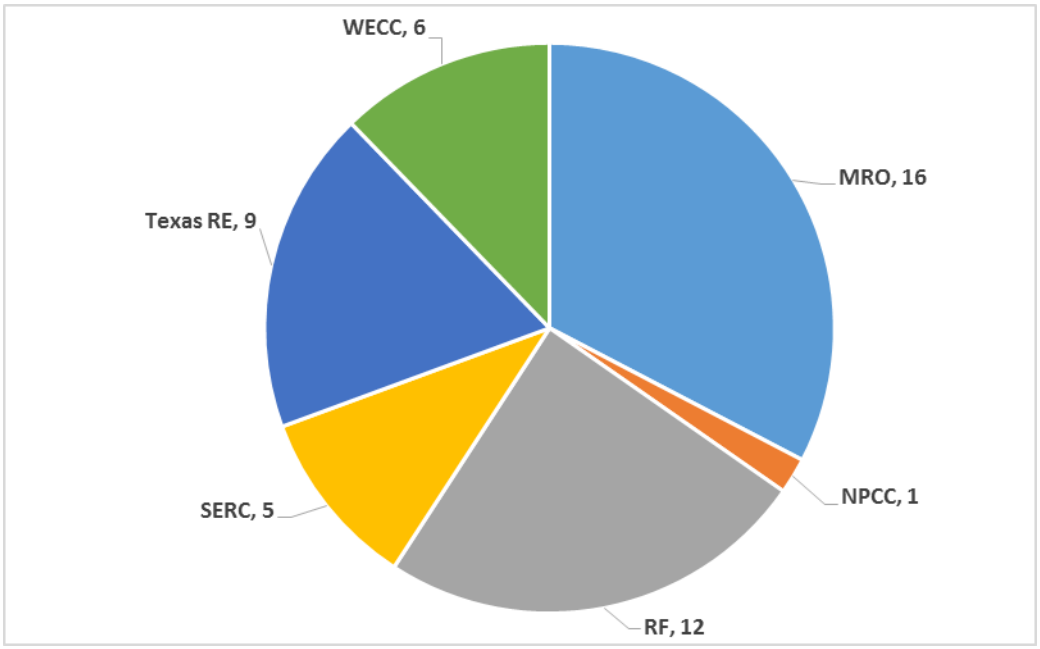


Figure 6 - Distribution of MRREs under coordinated oversight by LRE

d. Participation in ERO Enterprise CMEP Staff Training

NERC CMEP staff provide training to ERO Enterprise staff through workshops, instructor-led training events, and eLearning opportunities. Training opportunities focus on identifying gaps in staff knowledge and capabilities related to the risk-based CMEP. During the Assessment Period, NERC offered the following training opportunities for Regional Entity staff:

(i) A workshop called "From Theory to Field Application" attended by 175 Regional Entity staff. Participants learned about controls around Reliability Standards,

penalty calculations, CIP auditing of high and medium impact BES Cyber Systems, and Transmission Operations / Interconnection Reliability Operations.

(ii) CIP auditor training on network security reviews. Approximately 21 Regional Entity staff attended the training in person and 21 attended remotely.

(iii) NERC and the Regional Entities hold two sessions a year on audit team leadership skills. This course ensures that audit team leaders and certification team leaders possess the requisite skills to lead a Compliance Audit or certification team.

(iv) Annual three-day workshop attended by 150 CMEP staff focusing on internal controls and updates on key processes, tools and techniques applied to Operations and Planning and CIP Reliability Standards, and use of network analysis tool for CIP auditors.

(v) NERC holds approximately two days of training per year on risk assessment and penalty determination training exercises

e. Targeted Compliance Audits

(1) Regional Entity Compliance Monitoring Competency Evaluation Guide Audit

In 2018, NERC gathered and reviewed information related to the procedures undertaken by NERC and each Regional Entity to ensure the competency of Regional Entity compliance personnel and how it is tracked, monitored, and updated. The objective of this initiative was twofold. First, NERC sought to determine how it and the Regional Entities monitor, track, and update the professional competencies of Regional Entity compliance personnel. Second, it assessed how NERC and the Regional Entities verify that Regional Entity compliance personnel have and maintain the competencies necessary to execute their roles. NERC noted no non-conformance with the ROP by any of the Regional Entities.

(2) Regional Entity Internal Controls Evaluation Audit

The objective of the internal controls evaluation audit was to assess whether the Regional Entities are adequately and consistently evaluating registered entities' internal controls and using

the results to impact risk assessments associated with compliance monitoring activities. The audit did not reveal any violations of the ROP by either the Regional Entities or NERC.

2. Enforcement

During the Assessment Period, NERC's enforcement oversight consisted of two components: metrics and reviews of Regional Entity enforcement processes, as discussed below. Regional Entity performance, mandated by the formal oversight plans, are documented in quarterly Board of Trustee Compliance Committee reports, the annual CMEP report, the annual FFT/Compliance Exception Report as well as individual Regional Entity reports. These reports document findings, recommendations, enhancements and lessons learned for the Regional Entities.

As NERC transitioned its focus toward a risk-based CMEP, enforcement metrics shifted to include metrics such as: (i) the percentage of noncompliance that is self-reported; (ii) the number of repeat and serious violations that were aggravated due to compliance history; and (iii) the percentage of noncompliance with incomplete mitigation. NERC reports on its metrics, measured at the ERO Enterprise level, in an annual Compliance Monitoring and Enforcement Program report,[36] as well as in public quarterly reports to the NERC Board of Trustees Compliance Committee.[37]

The second component of NERC's enforcement oversight activities consists of reviewing specific Regional Entity enforcement processes and the Regional Entity's implementation of those processes. NERC has an annual evaluation program through which it oversees specific enforcement-related processes. A preliminary schedule is developed and provided to the Regional

[36] These reports are available on NERC's webpage at https://www.nerc.com/pa/comp/Pages/AnnualReports.aspx. Until 2017, these reports were also filed with the Commission in Docket No. RR15-2.

[37] The quarterly reports are available on NERC's website at https://www.nerc.com/gov/bot/BOTCC/Pages/ComplianceCommittee(BOTCC).aspx.

Entities. NERC provides guidance and feedback to the Regional Entities on opportunities to enhance consistency and effectiveness of such processes. These reviews prioritize specific elements of the CMEP on a rotating basis. NERC follows these reviews with a summary report and specific feedback letters to each Regional Entity. For example, NERC performs an annual review of the implementation of the FFT and Compliance Exception programs in conjunction with FERC and reports on the results of such reviews in an annual filing with the Commission in Docket No. RC11-6.

In the following sections, NERC examines the performance metrics used to evaluate the Regional Entities' performance of their enforcement obligations.

i. The ERO Enterprise Processes Noncompliance in a Timely and Effective Manner and Demonstrates Continued Progress in Using the Enforcement Program to Reduce Risks to Reliability

One metric NERC has consistently used to track enforcement processing performance during the Assessment Period is the "average age of noncompliance." The "average age of noncompliance" metric allows NERC to examine, on average, how long a Regional Entity takes to reach a final determination on a noncompliance, irrespective of final disposition (i.e., notice of penalty or FFT). During the Assessment Period, the average age of noncompliance decreased from approximately 12 months at its highest point in 2014 to 11.8 months at the end of 2018. NERC observes that there has been some variation in average violation age, with a trend upward from the five-year low of approximately seven months in mid-2017, but the overall average remains within NERC's goal that the average age of noncompliance should not exceed 12 months. The average age climbed to a similar peak by the end of 2018 for a number of reasons, chiefly, a sustained increase in discovered noncompliance resulting from the implementation of newly enforceable Reliability Standards in 2016.

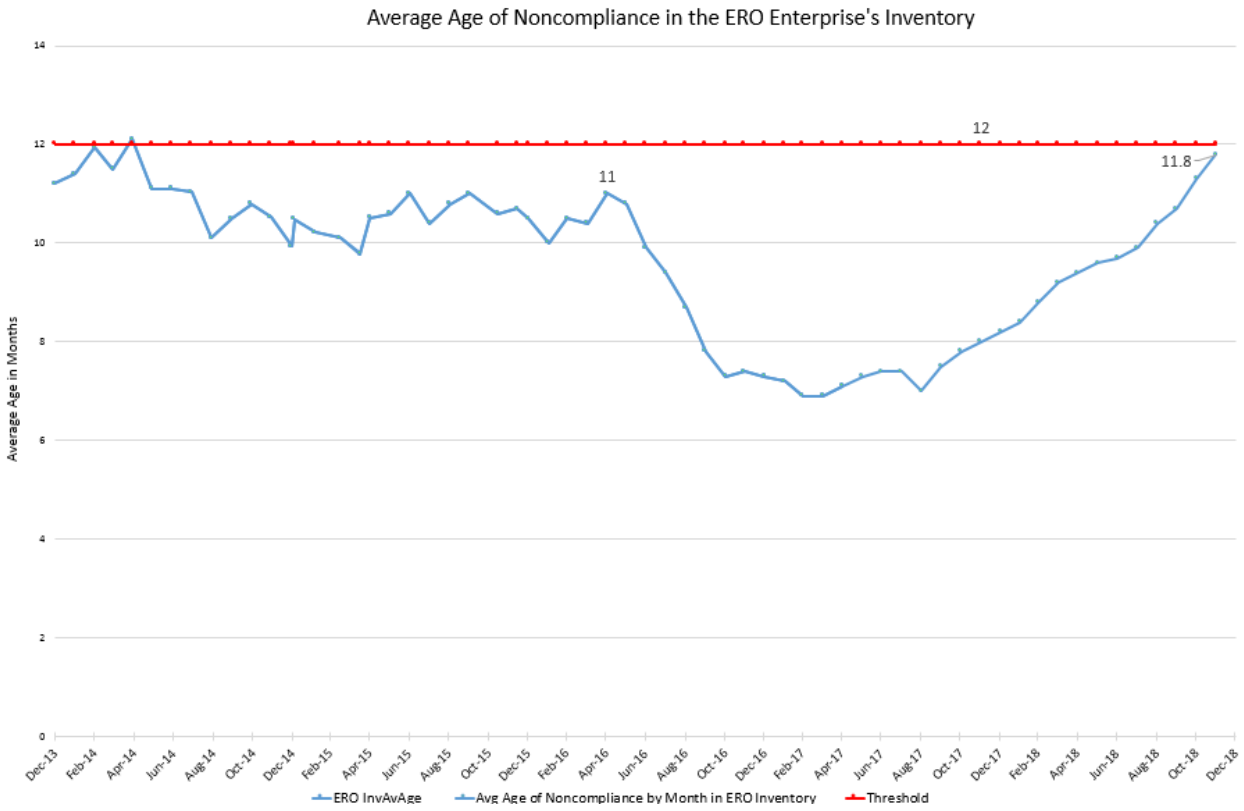


Figure 7 - Average Age of Noncompliance in the ERO Enterprise's Inventory[38]

As illustrated in the **Figure [7]** above, NERC observed an increase in the average age of noncompliance in inventory over the 2017-2018 timeframe. This increase in average age of noncompliance corresponds to a substantial increase in the amount of noncompliance discovered in the 2016-2018 timeframe compared to the 2014-2015 timeframe. The increase in discovered noncompliance, which peaked in the first quarter of 2017, is attributed to several new Reliability Standards coming into effect in July 2016 (including the CIP Version 5 standards).

The following chart compares the average age of noncompliance for each Regional Entity from January 1, 2015 (when the ERO average was approximately 10 months) to August 1, 2018 (when the ERO average was approximately 9.7 months):

[38] NERC notes that this chart excludes from the averages presented federal violations that were at one time placed on hold pending resolution of court proceedings.

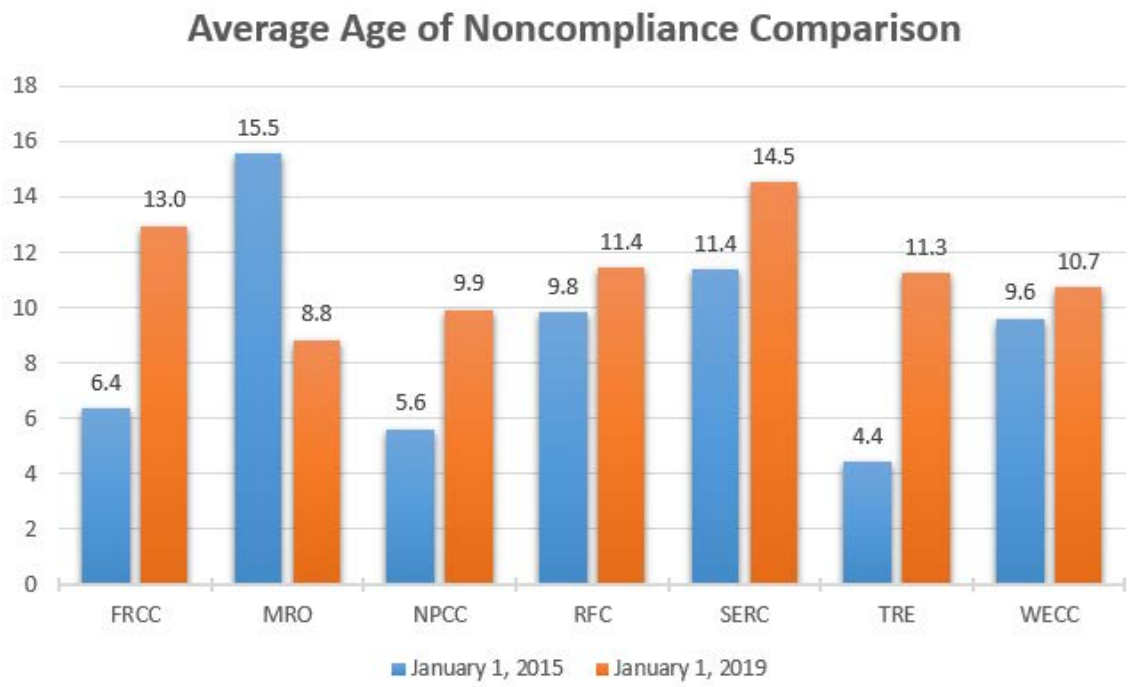


Figure 8 - Average Age of Noncompliance by Regional Entity, January 1, 2015 Compared to January 1, 2019

NERC observed that the average age of noncompliance varies by Regional Entity and can vary over time depending on the size, composition, and complexity of the Regional Entity's caseload.

A second metric NERC uses to measure the efficiency of enforcement processes is the disposition of minimal risk noncompliance. The ERO Enterprise has a streamline disposition track to process minimal risk noncompliance called the compliance exception track. This track requires prompt mitigation. Since most noncompliance involves minimal risk issues, increase used of the compliance exception track can improve processing efficiencies. The following **Figures [9-11]** show the percentage of minimal risk noncompliance processed as compliance exceptions for the years 2016-2018:

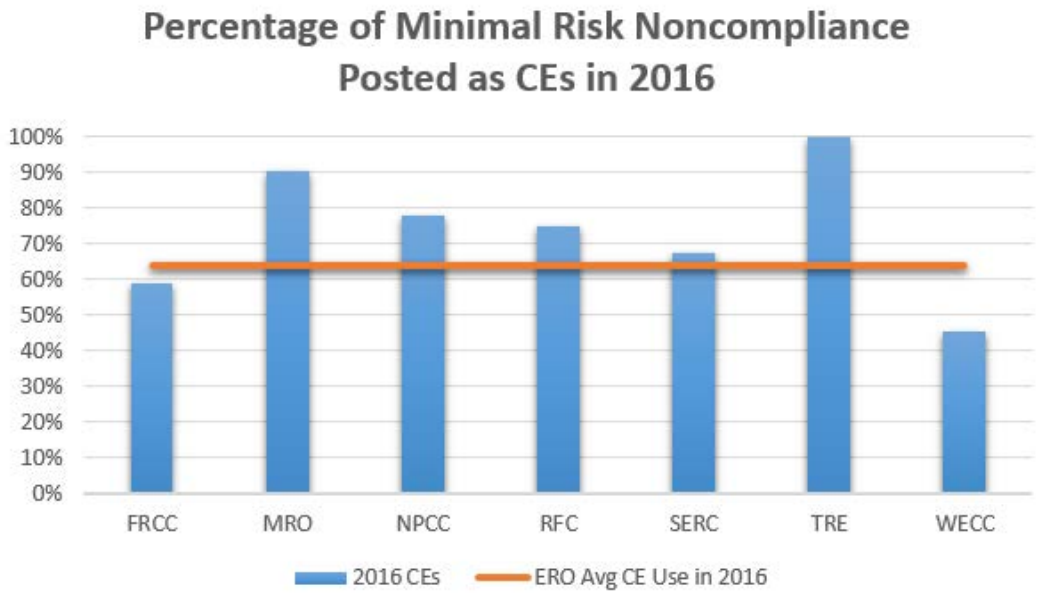


Figure 9 – Percentage of Minimal Risk of Noncompliance posted as CEs in 2016

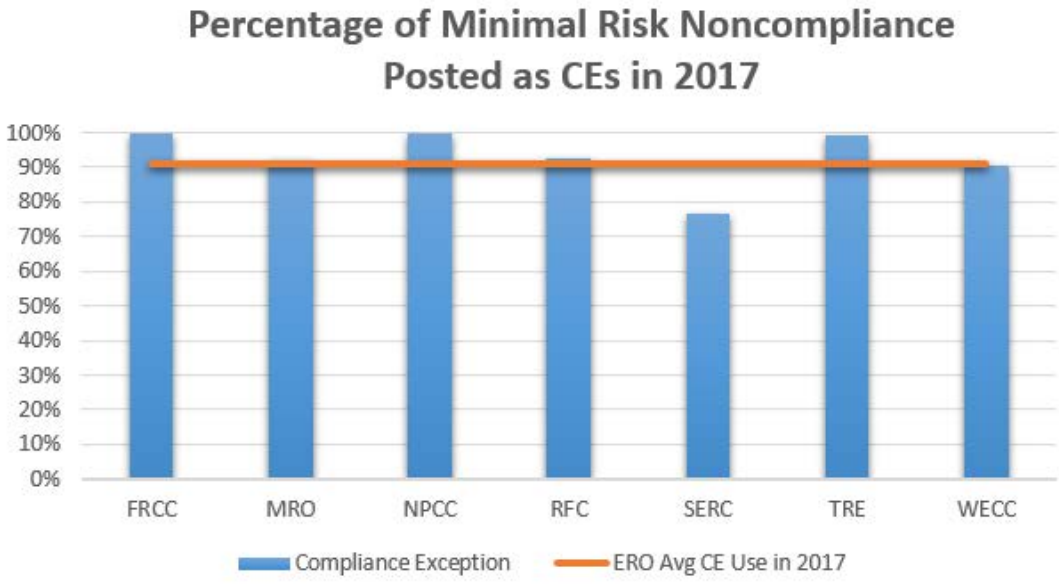


Figure 10 – Percentage of Minimal Risk of Noncompliance posted as CEs in 2017

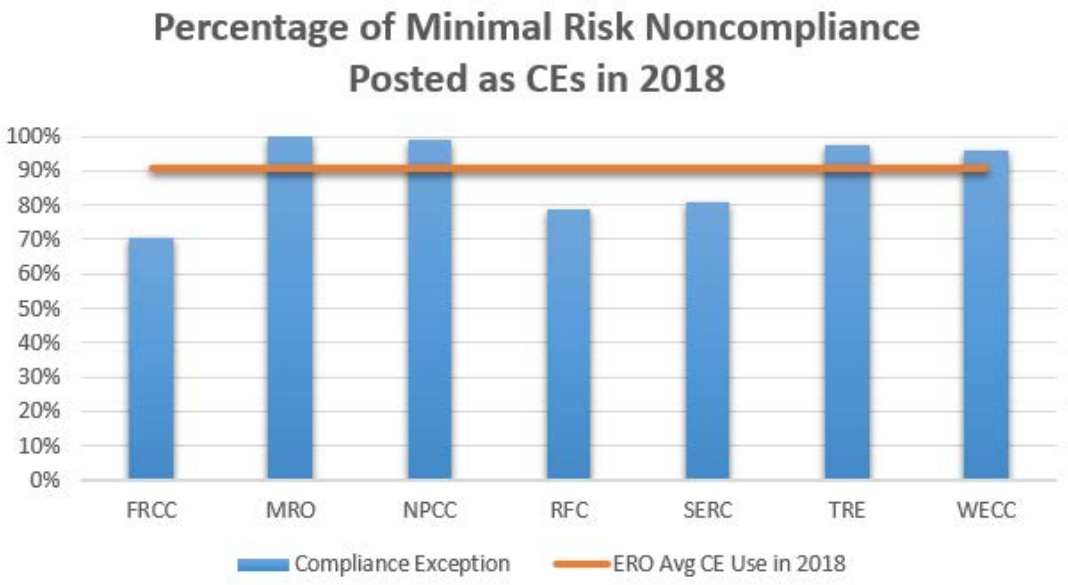


Figure 11 – Percentage of Minimal Risk of Noncompliance posted as CEs in 2018

NERC notes that each Regional Entity's use of the compliance exception track may depend on the composition of the Regional Entity's caseload; however, NERC has found that the Regional Entities have generally implemented this program in accordance with NERC's expectations.

NERC also monitors Regional Entity implementation of the self-logging program. The self-logging program, another component of NERC's risk-based enforcement program, allows registered entities with demonstrated effective management practices to keep track of minimal risk noncompliance (and related mitigation) on a log that is periodically reviewed by the Regional Entity. Minimal risk noncompliance added to the log is presumed to qualify for compliance exception treatment. After an initial pilot program, any registered entity may request evaluation by its Regional Entity in accordance with the program requirements. As of January 2019, 77 U.S. registered entities and one Canadian entity are participating in the self-logging program. **Figure [12]** below shows the distribution by Regional Entity:

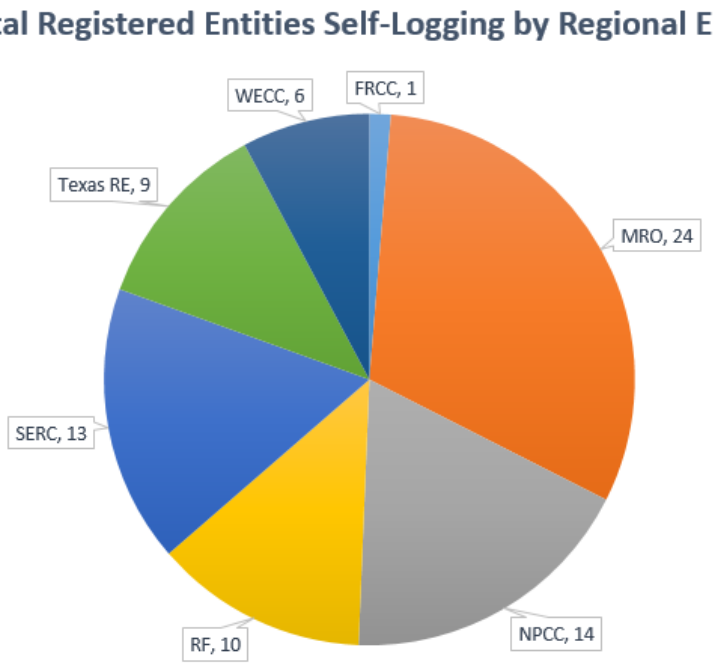


Figure 12 - Number of Registered Entities Participating in the Self-Logging Program by Regional Entity (current as of August 2018)

As discussed in detail below, NERC reviewed each Regional Entity's implementation of the self-logging program and has determined that each has implemented the program successfully and consistently during the Assessment Period.

ii. The ERO Enterprise Continues to Implement the FFT and Compliance Exception Programs Appropriately

Each year, NERC and the Commission perform a joint coordinated review of the implementation of the FFT and Compliance Exception programs during the prior year. NERC also files a report with the Commission summarizing the results of this review.[39] Through these

[39] Reports addressing the implementation of the program during the Assessment Period include: *North American Electric Reliability Corporation's Annual Report on the Find, Fix, Track, and Report Program* (Sep. 18, 2015); *North American Electric Reliability Corporation's Annual Report on the Find, Fix, Track and Report and Compliance Exception Programs* (Nov. 14, 2016); *North American Electric Reliability Corporation's Annual Report on the Find, Fix, Track and Report and Compliance Exception Programs* (Oct. 4, 2017), and *North American Electric*

reviews, and as described further in the individual annual reports, NERC has determined that the Regional Entities have implemented the FFT and compliance exception programs appropriately during the Assessment Period. Further, the Regional Entities have continued to improve the implementation of these risk-based enforcement programs during the Assessment Period, particularly with respect to identifying the root causes of noncompliance and identifying factors affecting the risk associated with individual noncompliance.[40] See *supra* Section IV regarding activities and accomplishments during the Assessment Period.

In the interest of continued improvement, NERC identified areas where Regional Entities could improve their implementation of the program and identified several best practices. NERC's observations are as follows:

(i) *Adherence to Relevant Rules and FERC Orders*. NERC found that each Regional Entity generally adhered to the relevant NERC ROP, CMEP, and FERC orders in its implementation of the FFT and Compliance Exception programs.

(ii) *Detailed and Updated Internal Procedures*. NERC found that each Regional Entity had comprehensive internal procedures to provide systematic guidance in the processing of noncompliance.

(iii) *Program Implementation*. NERC found that each Regional Entity implemented the FFT andCompliance Exception programs efficiently and that in each case reviewed, the selection of compliance exception or FFT treatment was appropriate. Following its review of each sampled case, NERC concluded that each Regional Entity generally included an appropriate discussion of the facts and circumstances of each case, an adequate evaluation of the root cause(s) of the noncompliance, an adequate risk assessment, and an adequate mitigation assessment. NERC, however, identified certain areas for continued improvement. Specifically:

Reliability Corporation's Annual Report on the Find, Fix, Track and Report and Compliance Exception Programs (Nov. 1, 2018), all filed in Docket No. RC11-6.

[40] In the 2014 performance assessment, NERC noted several opportunities for improvement across the ERO Enterprise, appropriately tailoring risk assessments, ensuring that internal Regional Entity program documentation remains up to date following program changes, and fully implementing processing efficiencies with respect to mitigation activities and verification of mitigation completion. *See also* NERC's Oct. 4, 2017 FFT and Compliance Exception filing at 7-8; *see also* Notice of Staff Review of Compliance Programs, Docket No. RC11-6-005 (Jun. 27, 2017).

- *Including Facts and Circumstances of Noncompliance in the Issue Description.* NERC observed that three Regional Entities could have included additional information in the issue description regarding the facts and circumstances of each noncompliance to improve clarity, although NERC found that none of the missing information was necessary to confirm the appropriateness of the ultimate disposition. NERC observed that one Regional Entity should consider whether to separate noncompliance into separate violation identification numbers when it involves multiple failures over a period of time. NERC made recommendations to two Regional Entities to include actual noncompliance duration dates.

- *Root Cause Evaluations.* NERC observed that some Regional Entities have greatly improved their evaluation and discussion of root causes. Such discussion is helpful in that it aids an entity in fully understanding the causes of its noncompliance and steps for effective mitigation.

- *Risk Assessments.* NERC observed opportunities for improvement of risk assessments. NERC recommended that sufficient information about the risk assessment be included. NERC specifically recommended that four Regional Entities ensure that risk assessments include a complete evaluation of relevant compliance history of registered entities and their affiliates, or state when there is no relevant compliance history. NERC identified as a best practice WECC's practice of providing a thorough noncompliance evaluation that includes looking at deeper issues such as the quality of internal controls.

- *Mitigation Actions.* NERC also found that each Regional Entity generally had the appropriate documentation from the registered entity to demonstrate completed mitigation.

iii. The ERO Enterprise is Successfully Implementing the Self-Logging Program

In 2017, NERC completed a review of Regional Entity implementation of the self-logging program. Following its review, NERC determined that the majority of the Regional Entities have successfully implemented the self-logging program. NERC offered, among other things, the following observations regarding Regional Entity implementation of the program:

(i) *Outreach and Participation.* NERC identified NPCC, MRO, and Texas RE as having exemplary outreach activities to promote participation in the program. Reliability First and WECC had robust self-logging programs with ongoing outreach and high entity participation. SERC had demonstrated improvement in its outreach.

(ii) *Determining Eligibility for Participation*. NERC confirmed there was adequate evidence and information to support each of the registered entities' eligibility for participation in the program. In addition, NERC found that the Regional Entities were consistently performing formal reviews of registered entities' internal controls for identifying, mitigating, and reporting minimal risk noncompliance. NERC found that the quality and detail of documentation that is maintained by the Regional Entities to track eligibility, evaluation, and notification of participation into the self-logging program after FERC's November 2015 order had improved compared to the documentation during the pilot phase of the program.

(iii) *Review of Logs*. NERC determined that the Regional Entities were each reviewing the logs for completeness and accuracy prior to submitting to NERC, and that the number of instances where the Regional Entities needed to contact the registered entities for additional information was small. NERC noted some differences in the level of detail in Regional Entity processes for reviewing logs.

(iv) *Verification of Mitigation*. NERC determined that each of the Regional Entities with active participants in the program conducted some method of verification that mitigation activities were being completed for self-logged noncompliance. NERC encouraged those Regional Entities still verifying mitigation activities for all noncompliance (NPCC, Texas RE, and WECC) to consider verification by sample to enhance the efficiency benefits of the program.

Since the conclusion of this review, more Regional Entities are verifying completion of mitigation through sampling methods. The ERO Enterprise is currently working on developing a single process for such sampling. By the end of the Assessment Period, there were 78 registered entities self-logging.

iv. The ERO Enterprise Strives to Improve its Mitigation Review Processes

In 2017-2018, NERC completed a review of Regional Entity evaluation of mitigation associated with a noncompliance by reviewing the Regional Entities' internal notes, processes, and any evidence the Regional Entities considered in order to determine whether the registered entity effectively and adequately mitigated a noncompliance. NERC recommended improvements for both the ERO as well as the Regional Entities. In its oversight role for this process, NERC completed the following during the Assessment Period:

(i) *Enhanced Internal Reviews*. NERC has modified internal processes to ensure that proposed mitigation actions adequately address identified causes and that sufficient internal controls exist to prevent recurrence.

(ii) *Training*. In 2018, NERC staff presented on issues related to mitigation at the annual CMEP workshop.

Overall, the Regional Entities are compliant with the CMEP; however, NERC will evaluate the following improvements moving forward:

(i) *Technology Improvements*. To promote the use of mitigating activities over formal mitigation plans, where applicable, the ERO Enterprise plans to implement a process in ALIGN that initially assigns all mitigation to start as mitigating activities and allows the Regional Entity to switch to the formal process if it determines the noncompliance needs a formal mitigation plan.

(ii) *Rule of Procedure Improvements*. Revisions to the ROP to increase the time period for review and acceptance of formal mitigation plans to ensure that the mitigation activities are adequate as well as to remove provisional acceptance of mitigation plans.

With respect to the Regional Entities, NERC recommends the following:

(i) *Procedure Modifications*. Regional Entities should modify procedures. where necessary, to clarify, among other things, (i) when a mitigation plan is required versus when mitigating activities are acceptable; and, (ii) the affidavit process by making it clear that affidavits are only required for noncompliance processed by the FFT disposition.

(ii) *Evidence*. Regional Entities should tie completion evidence to specific mitigation plan milestones or mitigating activities to ensure that all supporting documents are provided by the registered entity.

2. Conflict of Interest and Confidentiality Targeted Audit

NERC conducted an audit of each Regional Entity's business practices to safeguard confidential information and to prevent conflicts of interests within its organization. For this audit, NERC examined practices and procedures in place at the Regional Entities between January 2015 and May 2016 including data access protocols, document handling, training, contingency protocols, authorization procedures and security testing procedures.

NERC's audit testing found instances at two Regional Entities where individuals participated in a compliance audit without a valid confidentiality agreement, in violation of Section 402.8.2 of the ROP. In both instances, NERC recommended that the Regional Entity review its processes for obtaining and maintaining confidentiality agreements from compliance audit

participants to ensure they all have agreements that are valid and in effect. In both instances, the Regional Entity accepted the observation and mitigated the issue.

C. Organization Registration and Certification

NERC is responsible for devising and implementing the criteria that determine which BPS users, owners, and operators are subject to approved Reliability Standards and for maintaining the corresponding NERC Compliance Registry of organizations. NERC accomplishes this work through three functions – Registration, Certification, and BES Exception Requests. Through these functions, NERC monitors who is subject to compliance with its mandatory Reliability Standards.

It is worth noting here that registration criteria and Reliability Standards requirements are distinct from the Functional Model. The Functional Model does not describe which users, owners and operators of the BPS should be registered with the ERO. The Functional Model also does not contain a list of requirements applicable to registered entities. Instead, it is a reference tool identifying reliability-related tasks for users, owners and operators of the BPS. This reference tool enables standard drafting teams to understand the interrelationship between tasks performed by applicable entities. The Functional Model is also used as a guide for standard drafting teams to ensure that the appropriate applicable entities are listed under each Reliability Standard. Risks posed to the Bulk Power System and/or industry changes are more aptly addressed through revisions to registration criteria or requirements of the NERC Reliability Standards, rather than through changes to the Functional Model.

During the Assessment Period, NERC continued to examine how industry changes could impact registration criteria, particularly in the area of Distributed Energy Resources ("DER"). Today, NERC's registration criteria and its Reliability Standards applicable to generation

generally do not address resources connected to the grid at voltages below 100 kV, nor do they address resources with less than a registered capacity of 75 MVA in aggregate or an individual nameplate rating of 20 MVA. Furthermore, Reliability Standards are not written to apply to equipment within the distribution utility, unless it has a direct impact on the effect of grid reliability, such as load shedding or system restoration.

To further study the impact of DER, and the potential implications for registration and Reliability Standards, NERC formed an Essential Reliability Services Working Group ("ERSWG") which studied the changing resource mix in the context of monitoring grid reliability and resiliency. Specifically, it examined the need and steps to integrate higher DER penetration. The working group developed a report explaining how practices for modeling and operating the BPS may be enhanced to reflect future system characteristics. Building on the work of the ERSWG, the Planning Committee's System Planning Impacts from Distributed Energy Resources is examining key points of interest related to system planning, modeling, and reliability impacts to the BPS. The areas of focus for this group include:

(i) providing guidelines, white papers, compliance guidance, etc. in support of NERC Reliability Standards addressing interconnection requirements;

(ii) building off of existing NERC Reliability Guidelines for DER modeling and modeling practices, particularly for inclusion of DER in dynamic load models; and

(iii) assisting Event Analysis evaluations of BPS disturbances when aggregate DER are involved in the disturbance.

1. Registration

A key goal for NERC's registration function during the Assessment Period was developing common and consistent registration processes to promote efficiencies across the ERO Enterprise. NERC reviews Regional Entity execution of the Organization Registration Program to meet NERC's program goals and requirements. Areas that are reviewed may include the execution of

the Organization Registration Program (ROP§ 500), appeals process (ROP§§ 502-1.3), the functional mapping process (ROP §§ 501-1.4), and data management processes (confidentiality, integrity, and retention) (ROP§§ 502-2 and 1500). NERC tracks certain metrics to illustrate ERO Enterprise use of common and consistent registration processes to promote efficiencies.

Each Regional Entity supported ERO initiatives, such as the deployment of a new software tool for registration of Coordinated Functional Registration entities. Extending the functionality delivered with this tool, registration also has a new Centralized Organization Registration ERO System ("CORES") - tool which provides entity information to NERC for use in compliance monitoring and enforcement. This new system will be brought online in 2019 and coordinate with the ALIGN tool.

NERC oversaw the successful implementation of the Panel process beginning in 2016. NERC established the Panel with the goal of maintaining consistency and oversight in registration decisions made by the ERO Enterprise. NERC convenes a Panel to evaluate requests for: (i) deactivation of, or decisions not to register, an entity that meets the Registry Criteria; (ii) requests to add an entity that does not meet (i.e., falls below) the Registry Criteria; (iii) disputes regarding the application of the Registry Criteria; and (iv) requests for a sub-set list of applicable Reliability Standards. Any convened Panel is comprised of a NERC lead with Regional Entity participants. To date, NERC has received ten Panel requests, two of which were subsequently withdrawn. The Panel has issued seven determinations and has one open case whose decision is pending. Panel decision summary reports are posted on the NERC website.

NERC determined that each Regional Entity has met the requirements in Section 501 of the ROP, with respect to functional mapping. The functional mapping process is intended to ensure that: (i) no areas are lacking any registered entities to perform the duties and tasks identified in and

required by the Reliability Standards to the fullest extent practical; and (ii) there is no unnecessary duplication of such coverage or required oversight. NERC also verified that each of the Regional Entities has adequate data management processes and procedures to meet their data confidentiality, integrity, and retention obligations under the ROP. **Figures [13] – [18]** show the changes in registration activity during the Assessment Period.

Year	Type	BA	DP	DP-UFLS	GO	GOP	IA	LSE	PA/PC	PSE	RC	RP	RSG	RRSG	FRSG	TO	TOP	TP	TSP	Total
2014	Activation	4	7		67	70		8	3	29		1				4	1	6	1	201
	Deactivation	29	66		64	71	4	48		38	1	3				21	7	3	6	361
2015	Activation		1	44	76	90		2	3	14						8	1	2	2	243
	Deactivation		95		48	60	44	522	6	734		2				18	1	4	4	1538
2016	Activation			4	88	119									2	22	8	10	1	254
	Deactivation		23	4	64	86		3				3				10	2	1	1	197
2017	Activation		12	12	77	93			2			1				16	1	5	1	220
	Deactivation		16		43	61			1			1				12	4	1		139
2018	Activation	1	3	7	71	82			2							7		11		184
	Deactivation	9	68	2	177	181			6		3	29	3		1	44	20	28	6	577

Figure 13 – 5-Year (2014-2018) ERO Registration Activity by Function

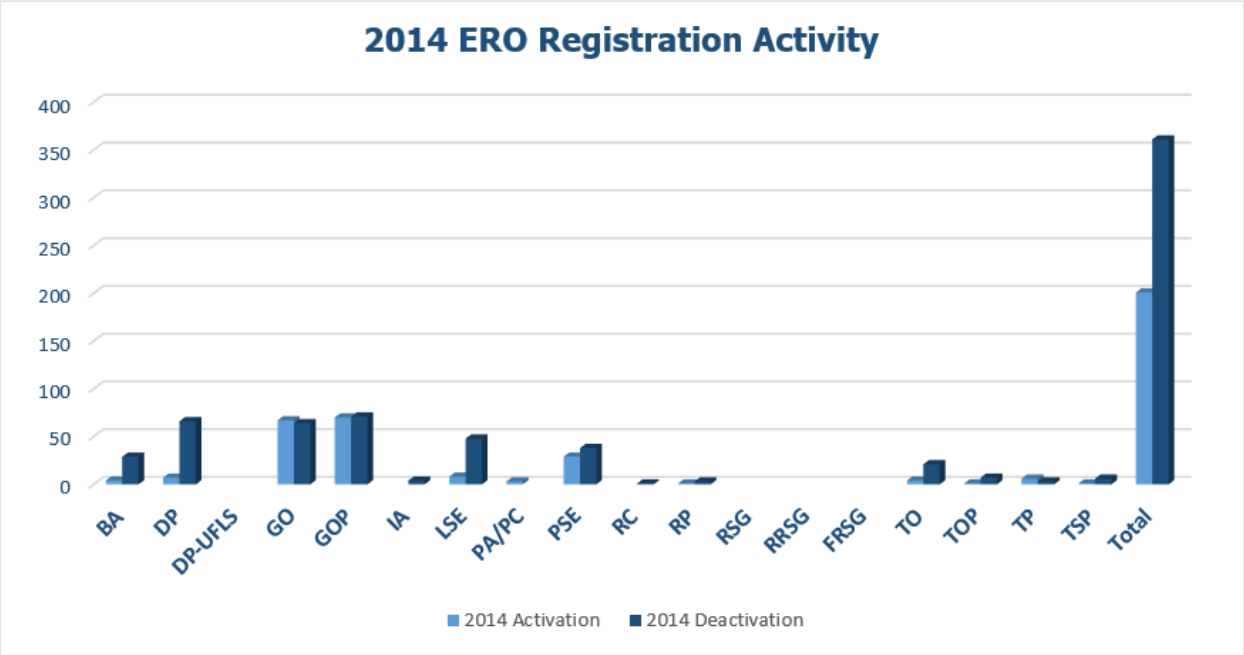


Figure 14 – 2014 ERO Registration Activity

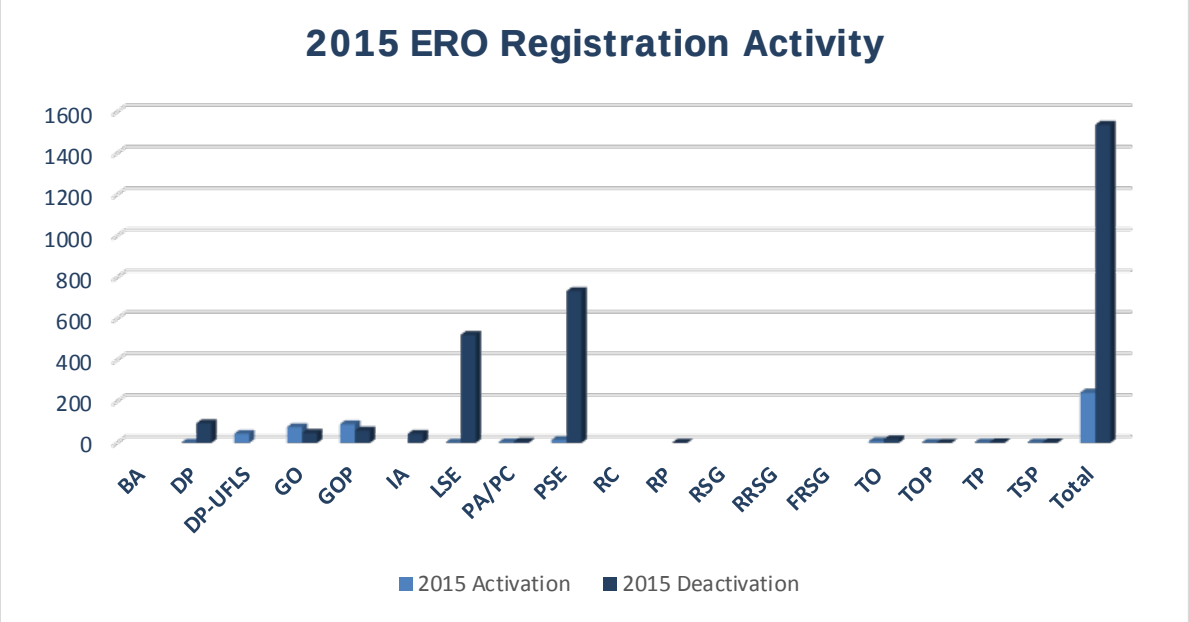


Figure 15 - 2015 ERO Registration Activity

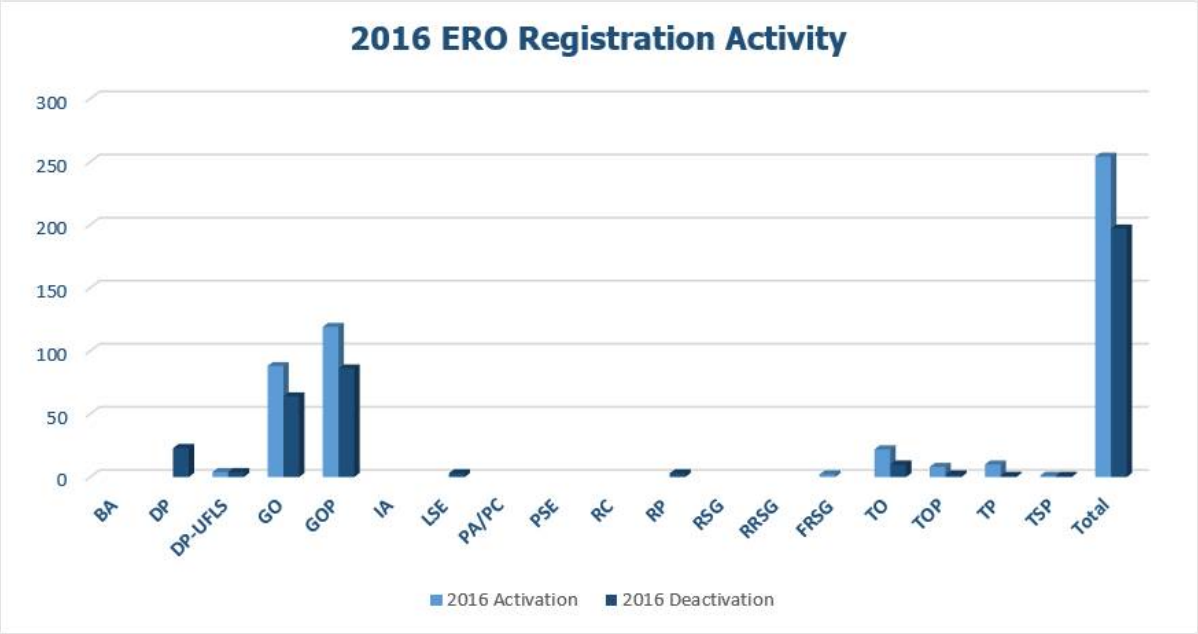


Figure 16 - 2016 ERO Registration Activity

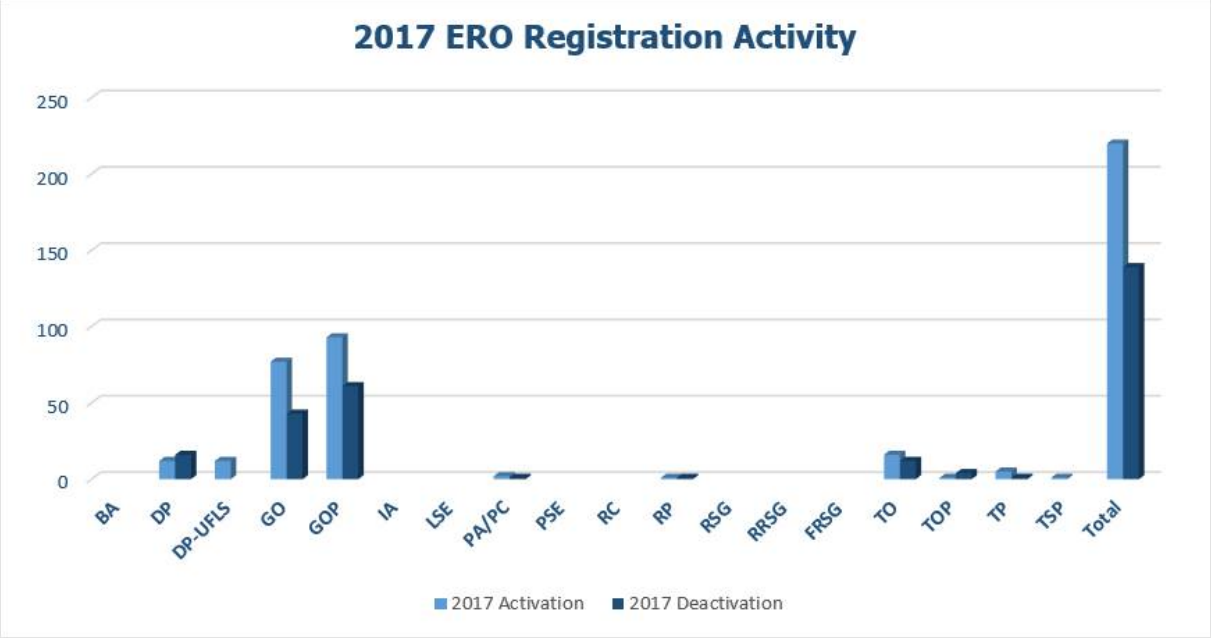


Figure 17 - 2017 ERO Registration Activity

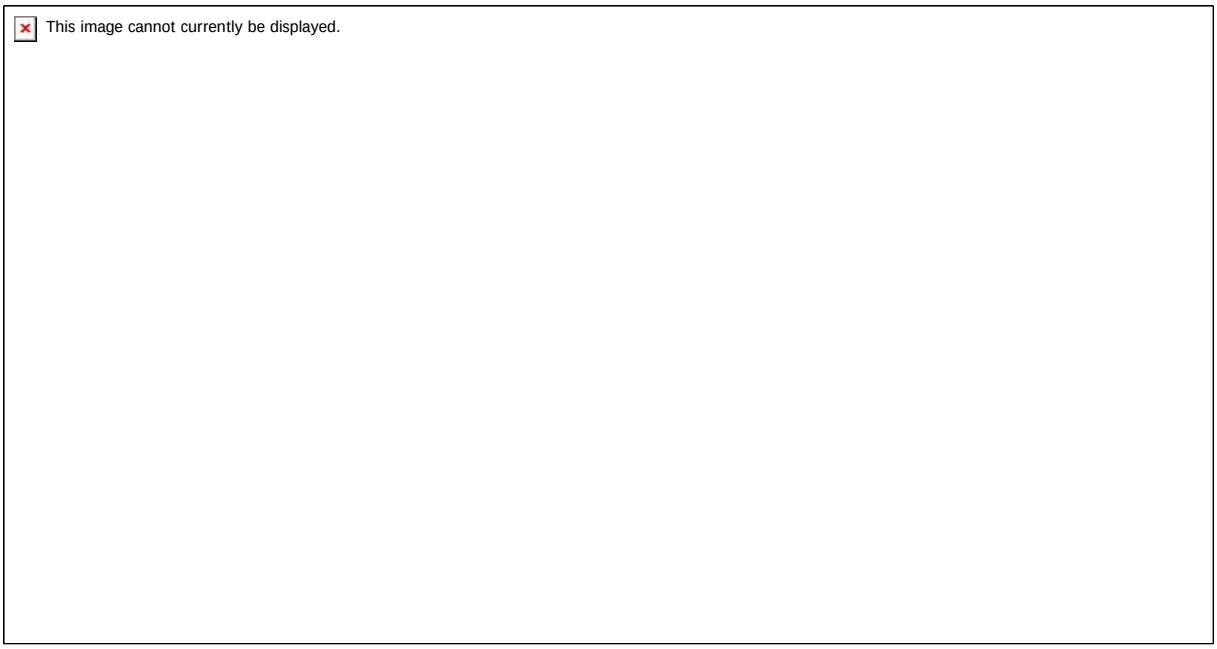


Figure 18 - 2018 ERO Registration Activity

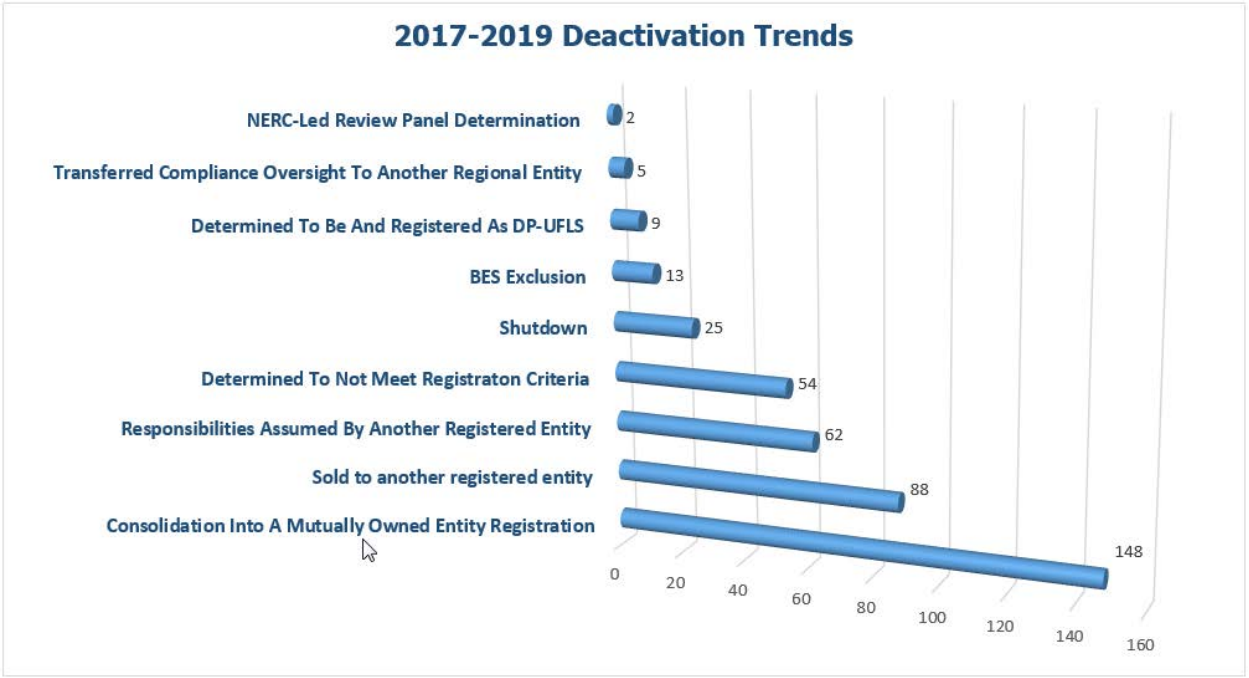


Figure 19 - 2017-2019 Deactivation Trends

2017-2019 Deactivation Trends

2017-2019 Deactivation Trends	
Consolidation Into A Mutually Owned Entity Registration	148
Sold to another registered entity	88
Responsibilities Assumed By Another Registered Entity	62
Determined To Not Meet Registraton Criteria	54
Shutdown	25
BES Exclusion	13
Determined To Be And Registered As DP-UFLS	9
Transferred Compliance Oversight To Another Regional Entity	5
NERC-Led Review Panel Determination	2

NERC is continuing to refine its metrics to provide more qualitative data for Regional Entity performance evaluation in future years.

2. Certification

During the Assessment Period, NERC revised training for certification and made it available to ERO Enterprise personnel and industry subject matter experts as an on-demand computer-based training module. Training now includes courses on Fundamentals of Auditing and Gathering Quality Evidence.

The 2018 CMEP Annual Report included results from NERC's first year of implementing the Certification oversight plan. These results included the ERO Enterprise's completion of one certification of a new Balancing Authority ("BA") and 12 certification reviews of already certified and operational entities. NERC accomplished certification oversight through direct participation in all certification engagements as required by NERC's ROP and participation on biweekly calls coordinating with Regional Entities. NERC also tracked fundamental program measures in the areas of utilization, fairness of administration, and consistency and comparability of executed process parameters. In 2019, Certification plans to complete processing one new Transmission

Operator, one new BA, and three new Reliability Coordinator certifications, as well as conducting at least four certification reviews.

3. BES Exception Requests

In Order No. 773, the Commission approved the revised BES Definition[41] and Appendix 5C of the ROP, providing procedures that registered entities might use to request exceptions to facility inclusion or exclusion from the BES Definition ("Exceptions Process"). During the Assessment Period, NERC developed a BES oversight plan and coordinated with the Regional Entities through a working group to implement the revised BES Definition and Exception Process. Through these efforts, the ERO Enterprise published implementation guidance for consistent evaluation of BES inclusions, exclusions, and self-notifications of Registration status under the ROP.

The BESnet Tool also enables NERC, Regional Entities, and Submitting Entities requesting an exception from the BES Definition to efficiently manage and review materials associated with an Exception Request. NERC has processed approximately five years of Exception Requests – totaling [37] Exclusion Exception Requests and seven Inclusion Exception Requests. NERC requires formal notification to its Registration function of Exception Request decisions and includes BES matters at each meeting with Regional Entities regarding Registration matters.

In 2017, NERC developed the BES Exceptions oversight plan as a mechanism for oversight of ERO Enterprise-wide activities under Appendix 5C of the ROP. These results are included in the 2018 CMEP Annual Report and reflect NERC's review of certifications of Exception Requests,

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41 *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012); *order on reh'g*, Order No. 773-A, 143 FERC ¶ 61,053, *order on reh'g and clarification*, 144 FERC ¶ 61,174 (2013), *aff'd sub nom.*, *New York v. FERC*, 783 F.3d 946 (2d. Cir. 2015).

examination of Inclusion and Exclusion Exception Requests, and confirmation of Self Determination Notifications regarding the BES status of Registered Entity facilities. In 2019, NERC will continue working with Regional Entities to ensure a coordinated and transparent approach to implementation of Appendix 5C of the ROP.

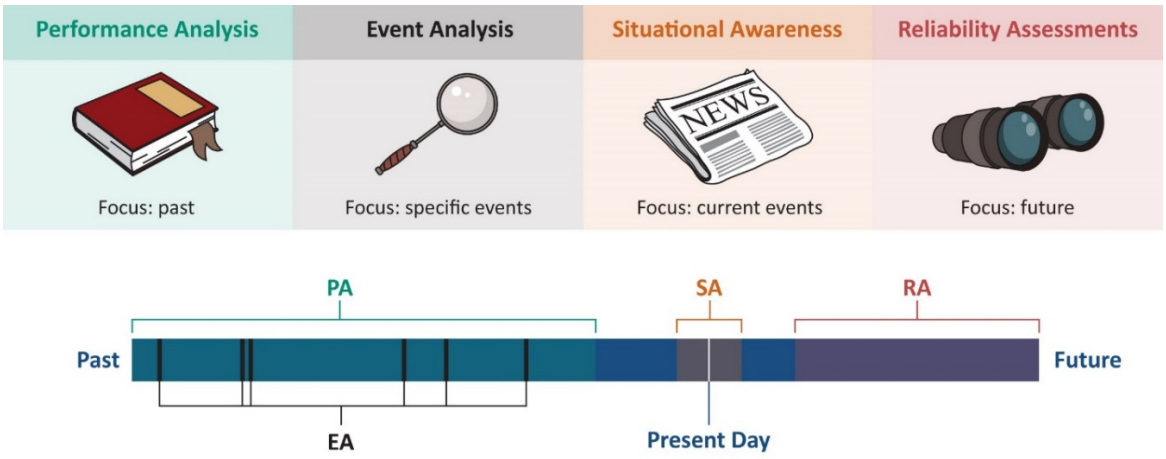
D. Reliability Assessments of the BPS

NERC fulfills its statutory obligation to "conduct periodic assessments of the reliability and adequacy of the [BPS] in North America"[42] through its work under the following functions: Bulk Power Situational Awareness ("SA"), Event Analysis ("EA"), Performance Analysis ("PA"), and Reliability Assessments ("RA"). These four functions gather and analyze data on the BPS and share the results of this analysis with the public. During the Assessment Period, these functions issued publications addressing the state of reliability, potential vulnerabilities in the BPS, and forward-looking analyses of the BPS.[43] The following diagram illustrates the relationship between the functions.

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42 16 U.S.C. § 824o(g).

43 ERO Enterprise tools support NERC's collaborative operations and are an important component of the effort to assure reliability. For example, the Misoperations Information Data Analysis System ("MIDAS") improves misoperations analysis coordination between NERC and the Regional Entities, leading to faster and more accurate identification of acute reliability risks. Another tool, the Reliability Assessment Data System ("RADS"), automates the process of collecting and validating data used in the development of long-term and seasonal reliability assessments. Further, NERC uses the Event Analysis Management System ("TEAMS") to collect information about specific reliability events for further analysis and potential lessons learned development. In addition, the Generator Availability Data System ("GADS") Wind tool provides a platform for registered entities to report information about the operation and performance of wind turbines.



These functions rely upon and leverage stakeholder expertise on the technical standing committees – namely the Planning Committee, the Operating Committee and the Critical Infrastructure Protection Committee. Each of these technical committees are comprised of subcommittees and working groups with Regional Entity representation. They brief the NERC Board on their work product on a quarterly basis. The scope of the work that they perform each year is documented in a work plan that is submitted to the NERC Board. Each technical committee has an executive committee that guides and coordinates the work produced by the subcommittees, working groups and task forces. To further coordinate issues that may be cross-cutting, the Chairs and Vice-Chairs (who sit on the executive committees) of all NERC technical standing committees meet on a quarterly basis, concurrent with the NERC Board and Member Representatives Committee ("MRC") meetings. NERC's trustees also attend those MRC meetings. Their work provides critical inputs for the aforementioned functions and enable NERC to identify ongoing trends and potential risks. NERC could not produce the following work product without the technical standing committees – annual State of Reliability Report; periodic reliability assessments; and the Blue Cut Fire Disturbance Report, which prompted the task force on

performance characteristics of utility-scale inverter-based resources (e.g., solar photovoltaic ("PV") and wind power resources) directly connected to the BPS.

The following section examines NERC oversight of Regional Entity activities for these Reliability Assessment functions.

1. Performance Analysis Regional Entity Performance

NERC measures Regional Entity performance in the PA process by evaluating if the Regional Entities are timely in sharing information (i.e., submission timelines in the relevant NERC PA database), responsive (i.e., quarterly evaluation of timelines in the relevant PA databases and annual evaluation of Regional Entity review of key findings during development of the State of Reliability Report), and active in training opportunities. As part of their work in this area, Regional Entities are responsible for validating data accuracy and completeness. For example, Regional Entity staff should report the percentage of registered entities in required reporting and follow up with missing submittals. The metrics outlined below for GADS, TADS and MIDAS stem from NERC's oversight plans for the Regional Entities. The technical standing committees, and more specifically their working groups, are also involved in evaluating the validity of these databases. For example, the GADS Working Group reviews and recommends new GADSs data collection categories, reviews additions and changes to GADS data reporting instructions, and analyzes trends and risks to reliability from generator availability and performance. NERC leverages the analysis of the technical standing committees to identify new risks and to determine the appropriate method to address the risk. For example, NERC has been working with stakeholders to evaluate a potential Section 1600 data request for solar facilities.

The primary area of improvement for the Regional Entities identified over the Assessment Period is in timely information sharing. NERC is working with Regional Entities to enhance activities to correct untimely or incomplete data submissions by responsible entities. In **Figures**

[**20**]-[**24**] below, NERC tracks submission rates for the Regional Entities.[44]

2017 GADS and TADS Submissions (Report Date: March 29, 2018)									
Percentage of Complete Data Submissions									
Reporting Quarter	2017-Q1		2017-Q2		2017-Q3		2017-Q4		
	GADS	TADS	GADS	TADS	GADS	TADS	GADS	TADS	
MRO	90%	100%	90%	100%	90%	100%	90%	100%	
NPCC	98%	100%	98%	100%	98%	100%	98%	100%	
RF	99%	100%	99%	100%	99%	100%	99%	100%	
SERC	99%	97%	99%	94%	99%	97%	99%	91%	
Texas RE	100%	100%	100%	100%	100%	100%	100%	100%	
WECC	95%	99%	95%	99%	95%	99%	95%	99%	

Figure 20 - 2017 GADS and TADS Submissions (Report Date: March 29, 2018)

2018 GADS and TADS Submissions								
Percentage of Complete Data Submissions								
Reporting Quarter	2018-Q1		2018-Q2		2018-Q3		2018-Q3	
	GADS	TADS	GADS	TADS	GADS	TADS	GADS	TADS
MRO	92.8%	96.4%	92.8%	90.9%	88.4%	81.8%	79.1%	100.0%
NPCC	87.4%	74.1%	87.4%	74.1%	87.4%	55.6%	96.9%	100.0%
RF	97.4%	100.0%	96.8%	96.6%	94.2%	100.0%	98.7%	100.0%
SERC	86.8%	97.1%	85.1%	94.3%	82.6%	74.3%	99.1%	100.0%
Texas RE	93.4%	57.7%	93.4%	50.0%	88.5%	50.0%	100.0%	100.0%
WECC	87.7%	86.5%	86.4%	79.7%	74.0%	74.3%	98.0%	98.6%

Figure 22 - 2018 GADS and TADS Submissions (Report Date: December 19, 2018)

[44] SPP RE is excluded from these tables due to the termination of its RDA with NERC.

Please note that MIDAS percentages may have reflected a lower than expected percentage of completion due to confusion regarding the process for opting out of Misoperations reporting by responsible entities claiming to not have owned any Composite Protection Systems protecting BES Elements.

Please also note, tables may not reflect most recently submitted data or the impacts of recent Regional Entity transfers.

2017 MIDAS Submissions				
Percentage of Complete Data Submissions				
Reporting Quarter	2017-Q1	2017-Q2	2017-Q3	2017-Q4
	MIDAS	MIDAS	MIDAS	MIDAS
MRO	77%	77%	81%	79%
NPCC	87%	87%	81%	77%
RF	91%	92%	90%	92%
SERC	93%	91%	92%	94%
Texas RE	90%	91%	81%	84%
WECC	96%	95%	97%	99%

Figure 23 - 2017 MIDAS Submissions (Report Date: March 29, 2018)

2018 MIDAS Submissions (Report Date: December 19, 2018)				
Percentage of Complete Data Submissions				
Reporting Quarter	2018-Q1	2018-Q2	2018-Q3	2018-Q4
	MIDAS	MIDAS	MIDAS	MIDAS
MRO	96%	96%	97%	98%
NPCC	89%	90%	89%	91%
RF	96%	99%	98%	98%
SERC	99%	97%	99%	99%
Texas RE	97%	95%	94%	96%
WECC	99%	99%	100%	100%

Figure 24 - 2017 MIDAS Submissions (Report Date: December 19, 2018)

2. Events Analysis Regional Entity Performance

The EA function facilitates the sharing of lessons learned from applicable system events and trends to enhance reliability. The EA Process ("EAP") provides a structured framework for analyzing events on the system.[45] During the Assessment Period, the ERO Enterprise received hundreds of new qualified events, including Hurricanes Harvey and Irma as the first Category 5 Events since 2012. Texas RE, FRCC and SERC compiled reports to capture impacts and high-level lessons learned from these storms. Hurricanes Michael and Florence occurred in 2018. FRCC and SERC, respectively, are compiling reports to capture impacts and identify high-level

[45] The Event Analysis Process is posted on the NERC website at: http://www.nerc.com/pa/rrm/ea/EA%20Program%20Document%20Library/ERO_EAP_V3_final.pdf.

lessons learned and effective practices from the planning, preparation, and response to these storms. Further collaborative analysis took place with WECC for a 2016 California Independent System Operator, Inc. frequency excursion and the 2016 Blue Cut Fire. In addition, NERC conducted a joint analysis with RF, SERC, and WECC in 2017 regarding the impact of the total solar eclipse on photovoltaic energy production. Additionally, collaborative analysis took place with WECC for the October 2018 solar generation loss event. In 2018, a wildfire (Canyon 2 Fire) caused transmission line faults that triggered 900 MW of solar resource loss. A major disturbance report was published and a second solar loss alert was issued as a result of this analysis. Outreach activities included publishing lessons learned, hosting annual Monitoring and Situational Awareness Technical Conferences, providing industry-wide causal analysis training, and conducting workshops in MRO, RF, Texas RE, and WECC addressing protective relay misoperations. NERC also provided trending data about event counts and impact in support of Regional Entity workshops and conferences.

NERC tracks Regional Entity performance by focusing on the following:

(i) Initial Report Completion - measuring the average time between event occurrence and NERC's receipt of an initial report compared with the goal time period specified in the EA Process;

(ii) Final Report Completion - measuring the average time between event occurrence and NERC's receipt of a final brief report or event analysis report;

(iii) Cause Coding - tracking average time between event occurrence and completion of entity-involved cause coding. Cause Coding seeks to characterize the causes of reportable events in a structured, measurable, and continuously improvable method;

(iv) Lessons Learned Development/Publishing - tracking the number of events leading to published lessons learned from registered entities in the Regional Entity area; and,

(v) EA Qualifying Event Processing and Closure - measuring average time for an event to be processed.

During the Assessment Period, the ERO Enterprise exhibited good performance in analyzing, understanding, and communicating lessons learned from events affecting reliability of the BPS (*see* **Figures [29 – 31]**). Nonetheless, NERC may apply incrementally more active oversight over Regional Entities regarding the timeliness of initial and final brief reports, as well as consistency of outcomes while still respecting Regional differences.

The following tables and graphs provide a Regional Entity by Regional Entity comparison of performance in 2017 and 2018.

Category 1-5 Events Only (2017)							
Region	**Number of Events**	**Number of Events with EOP-004 or OE-417**	**Number of Events with BR**	**Number of Events started with EOP or OE and resulted in BR**	**Average workdays to initial BR received at NERC**	**Number of Events with Final BR**	**Average workdays to Final BR received at NERC**
FRCC	9	8	8	7	24.00	8	24.63
MRO	39	34	38	33	26.47	20	28.80
NPCC	23	21	23	21	15.09	18	22.78
RF	37	31	35	29	16.34	35	23.69
SERC	18	16	12	10	27.92	9	27.78
Texas RE	11	8	11	7	13.20	6	19.50
WECC	30	22	25	18	17.76	22	28.73
Total	167	140	152	125	20.05	118	25.52

Figure [25·] – Report Completion (2017)

Category 1-5 Events Only (2018)							
Region	**Number of Events**	**Number of Events with EOP-004 or OE-417**	**Number of Events with BR**	**Number of Events started with EOP or OE and resulted in BR**	**Average workdays to initial BR received at NERC**	**Number of Events with Final BR**	**Average workdays to Final BR received at NERC**
FRCC	2	2	1	1	17.00	1	27.00
MRO	20	15	20	15	20.00	12	18.50
NPCC	26	22	26	22	17.38	22	26.23
RF	40	32	38	30	13.76	35	17.14
SERC	32	32	17	17	22.00	14	23.86
Texas RE	11	9	10	8	32.70	10	39.60
WECC	33	21	33	21	17.15	24	33.79
Total	**164**	**133**	**145**	**114**	**18.34**	**118**	**25.14**

Figure [26·] - Report Completion (2018)

Figures [27-31] illustrate the Cause Code Assignment Process ("CCAP") followed by NERC and the Regional Entities to assign cause codes after an event on the BPS is analyzed for the two years during which oversight plans were in place for Event Analysis. The charts in each figure measure the number of events at issue, per Regional Entity, for each stage of CCAP. The four stages of the CCAP represented are:

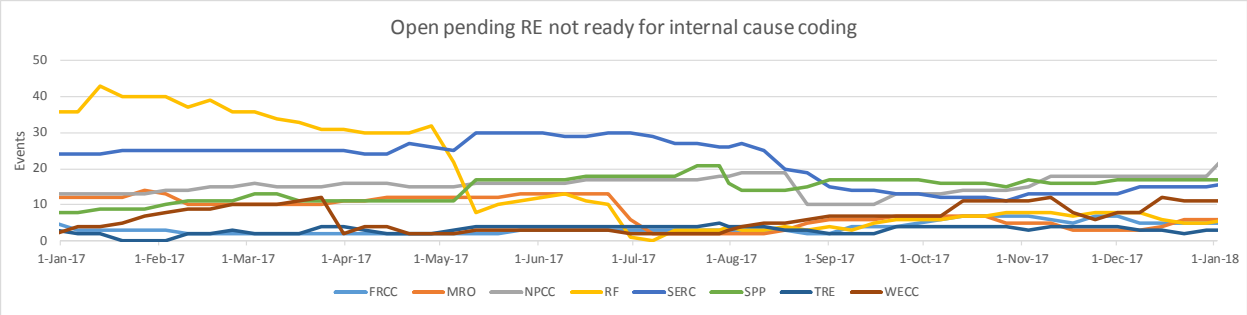
(i) the receipt of event analysis brief reports[46] by the Regional Entities from registered entities;

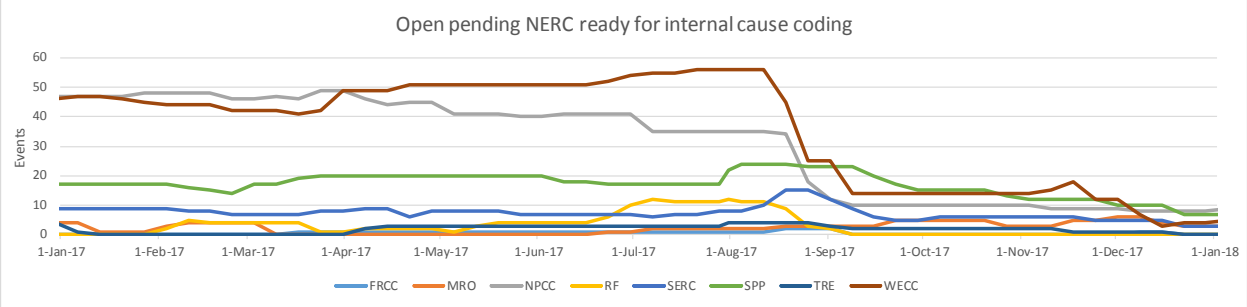
(ii) the receipt of event analysis brief reports by NERC from the Regional Entities and internal cause coding of the event;

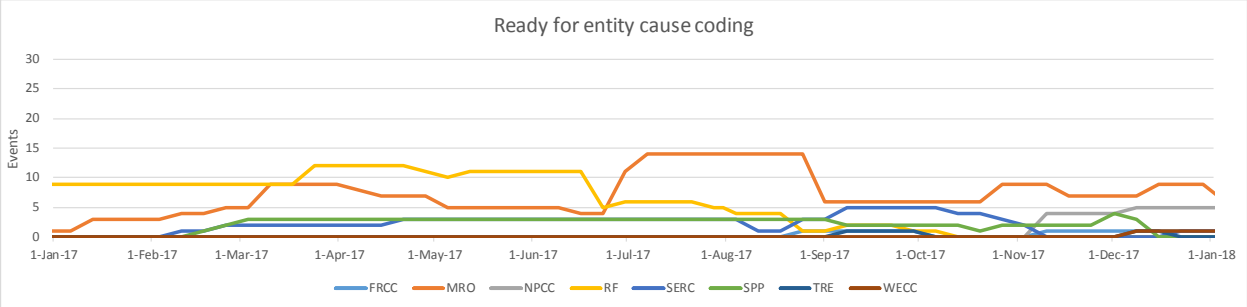
(iii) external cause coding discussion with registered entity, NERC and the Regional Entities; and

(iv) the completion of cause coding by NERC and the Regional Entity.

[46] Registered entities impacted by an event prepare brief reports for all qualifying events.







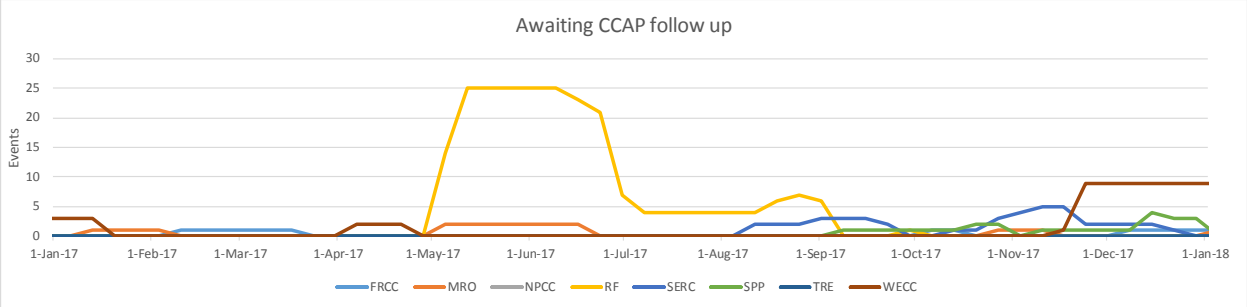


Figure [27·] - Cause Coding (2017)

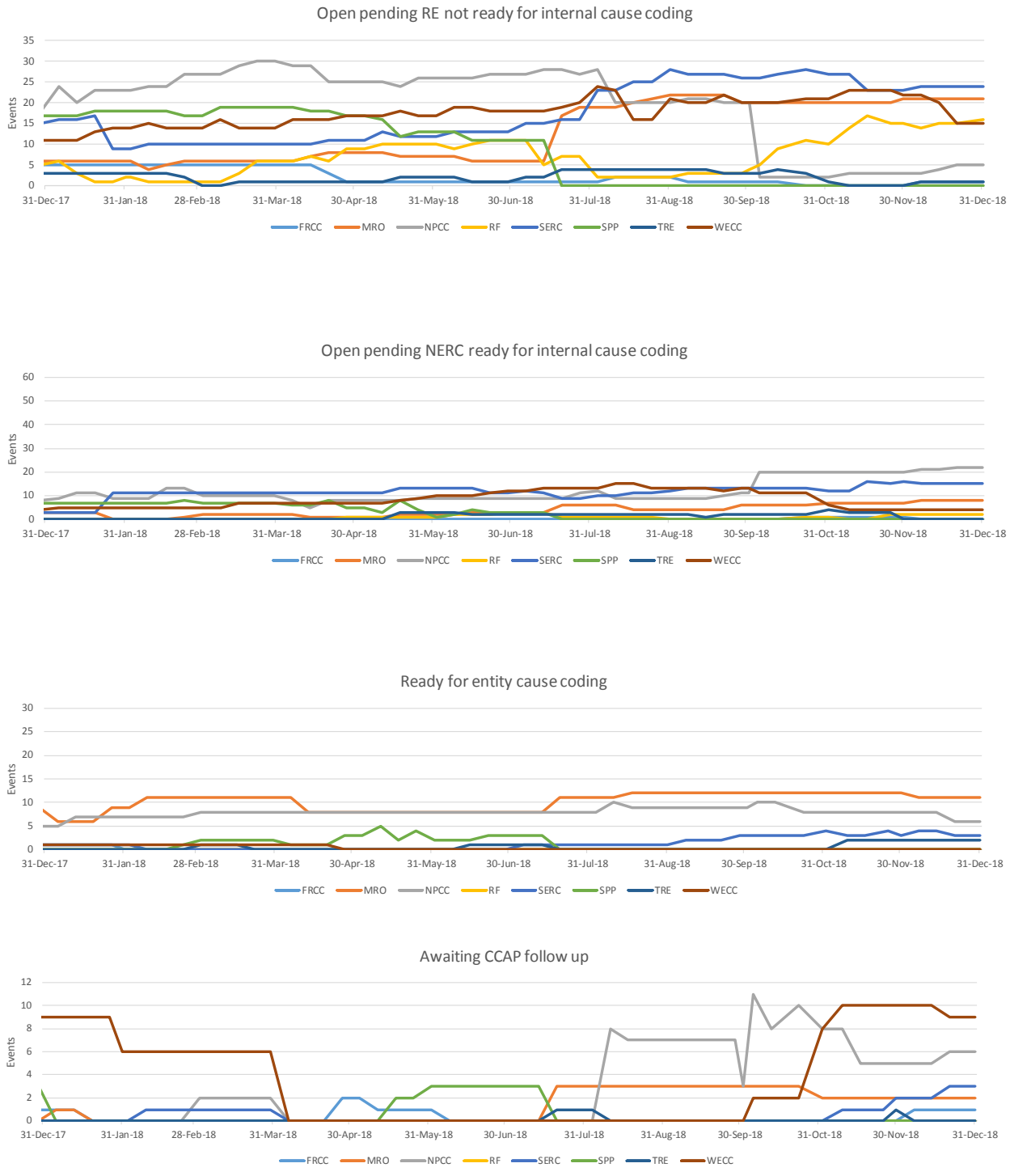


Figure [28·] - Cause Coding (2018)

Region	2014	2015	2016	2017	2018	Total
FRCC	3	1	2	0	**0**	**7**
MRO	1	0	2	0	**3**	**13**
NERC	1	0	0	1	**0**	**26**
NPCC	4	10	6	2	**4**	**38**
RF	4	1	1	1	**5**	**19**
SERC	1	1	0	0	**0**	**4**
Texas RE	2	1	1	2	**0**	**20**
WECC	1	1	1	3	**3**	**22**
Total	**19**	**16**	**13**	**9**	**15**	**149**

Figure [29] - Lessons Learned Development

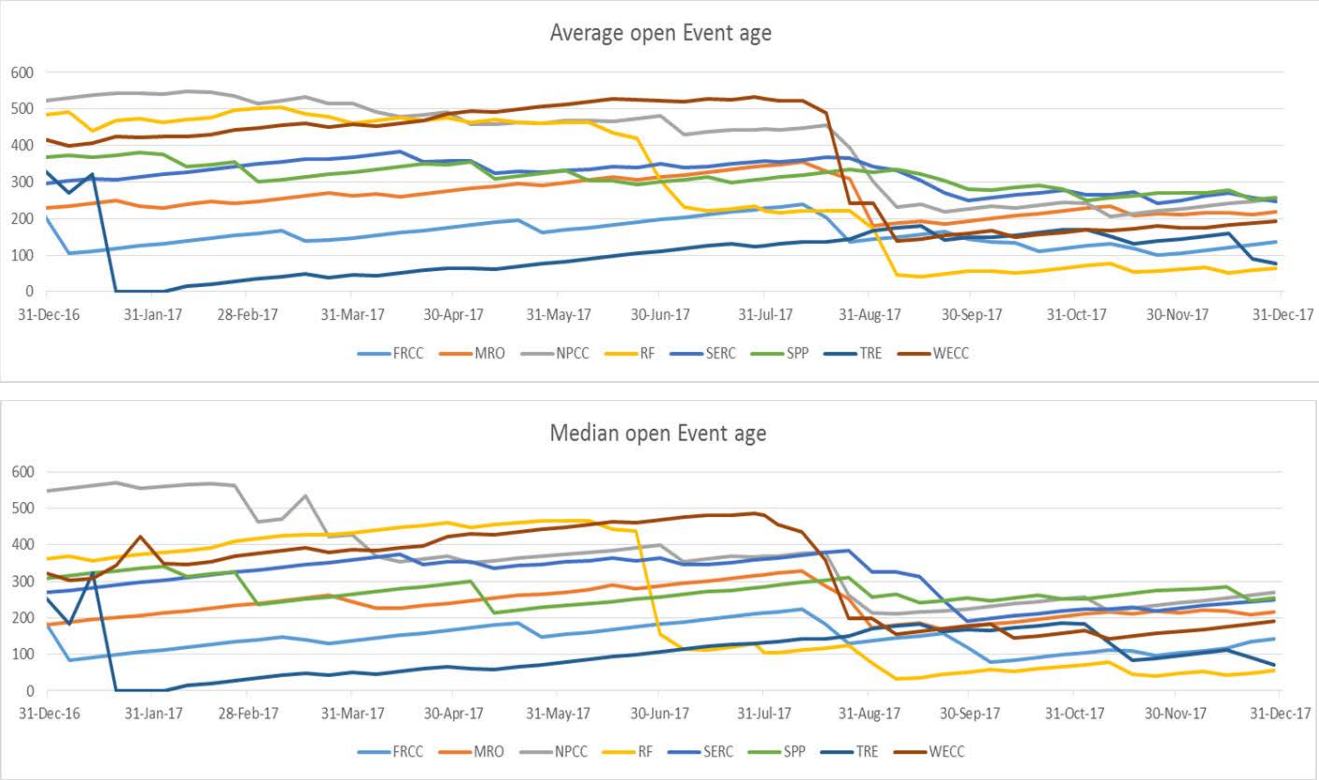


Figure [30·] - EA Qualifying Event Processing and Closure (2017)

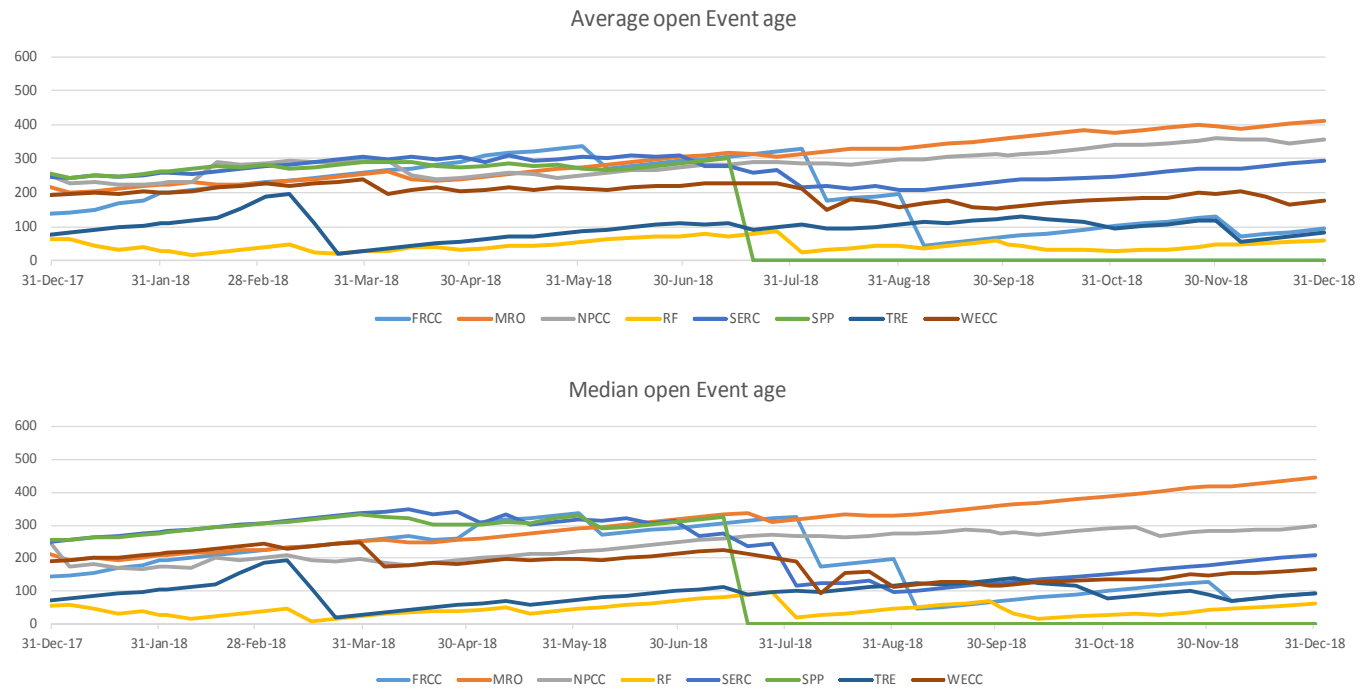


Figure [31] - EA Qualifying Event Processing and Closure (2018)

3. Targeted Event Analysis Audit

A catastrophic event on the BES is a significant risk to ERO Enterprise operations. As a result, NERC conducted a targeted audit of the EAP to examine Regional Entity compliance with the EA processes and procedures. The EA function is the main control of the ERO against a catastrophic event occurring. The targeted audit covered the January 2016 to July 2017 period. NERC found that all Regional Entities met the requirements of the ROP and Regional Delegation Agreements ("RDAs"). There were no instances of noncompliance by any Regional Entity for the ROP requirements in this area. Since all of the Regional Entities complied with requirements of the program, the audit focused on identifying leading practices and areas for greater consistency and alignment amongst the Regional Entities.

4. Situational Awareness Regional Entity Performance

NERC and Regional Entity SA functions coordinated to enhance industry's understanding of conditions and reliability risks to the BPS for several events that occurred during the Assessment Period. These events included hurricanes Harvey (Texas RE), Irma and Matthew (FRCC, SERC); wildfires around Santa Barbara, CA (WECC); winter storms in the Northeast and Pacific Northwest (NPCC, WECC); and the onset of a period of extreme cold weather and high loads for the last week of 2017 (MRO, RF, SERC). GridEx IV also brought NERC and Regional Entities together to practice triage and response to a simulated continent-wide coordinated attack on the BPS, bringing in cyber and physical security-related topics in a realistic exercise environment. **Figures [32] - [33]** show the incidence of events and occurrences during the Assessment Period.

2017 Situation Awareness Events, Occurrences, and Reports by Regional Entity					
Region	**Number of Events and Occurrences**	**Number of EOP-004 Reports**	**Number of OE-417 Reports**	**Number of EEA-3 Declarations**	**Metric 3 Firm Load Shed over 300 MW**
FRCC	17	9	7	0	0
MRO	32	26	6	0	0
NPCC	39	32	7	0	1
RF	69	59	10	0	0
SERC	68	35	33	0	0
SPP	31	25	6	0	0
Texas RE	24	17	7	0	0
WECC	129	85	44	5	1
Total	**409**	**288**	**120**	**5**	**2**

Figure [32] -2017 Situation Awareness Events, Occurrences, and Reports by Regional Entity

2018 Situation Awareness Events, Occurrences, and Reports by Regional Entity					
Region	**Number of Events and Occurrences**	**Number of EOP-004 Reports**	**Number of OE-417 Reports**	**Number of EEA-3 Declarations**	**Metric 3 Firm Load Shed over 300 MW[47]**
FRCC	15	7	8	3	0
MRO	49	41	8	8	0
NPCC	231	207	24	1	0
RF	104	43	61	0	0
SERC	106	56	50	0	0
Texas RE	41	29	12	0	0
WECC	159	91	68	4	0
Total	**705**	**474**	**231**	**16**	**0**

Figure [33] - 2018 Situation Awareness Events, Occurrences, and Reports by Regional Entity

Situational Awareness (including near Real-time data captured under SAFNR) helps ensure that the ERO Enterprise is aware of the Real-time status and any pressing needs of the BPS. SAFNR data provides NERC with near Real-time information about the BPS. This allows NERC to coordinate with federal and local agencies and authorities during an event or severe weather.

5. Reliability Assessments Regional Entity Performance

NERC evaluates Regional Entity performance by evaluating the following metrics using a scale of 1 to 3 (3 = highest point possible):

(i) Accuracy – the degree to which the result of a measurement, calculation, or specification conforms to NERC instructions and processes;

(ii) Timeliness – submitting materials on or before a specified date and time;

(iii) Responsiveness – responding to appeals, questions, peer feedback, and requests;

(iv) Completeness – answering questions and including all relevant information, data, and analysis; and

[47] 2018 ERO Enterprise Metrics, http://departments.internal.nerc.com/legalregulatory/MainDocuments/Exhibit%20C%20to%202019%20Five%20Year%20Performance%20Assessment.pdf?Web=1.

(v) Validity – data and information supporting the assessments are supported and adhere to NERC definitions and instructions.

i. Individual Regional Entity Performance

For the Summer and Winter Reliability Assessments, a total of 15 points can be earned toward the final score.

2018 Summer Assessment							
	FRCC	**MRO**	**NPCC**	**RF**	**SERC**	**TRE**	**WECC**
Processes in place to validate data	2	2	2	2	3	3	2
Narratives are consistent with submitted data	2	2	2	2	2	2	2
On-time data and narratives	1	3	3	3	3	3	2
Narratives complete and comprehensive	2	2	2	1	2	3	1
Responsive to NERC	3	3	3	3	3	3	3
TOTAL	10	12	12	11	13	14	10

2018 Winter Assessment							
	FRCC	**MRO**	**NPCC**	**RF**	**SERC**	**TRE**	**WECC**
Processes in place to validate data	2	2	2	2	3	3	2
Narratives are consistent with submitted data	2	2	2	2	2	2	2
On-time data and narratives	3	3	3	1	3	3	3
Narratives complete and comprehensive	2	2	2	2	2	2	2
Responsive to NERC	3	3	3	3	3	3	3
TOTAL	12	12	12	10	13	13	12

For the Long-Term Reliability and Probabilistic Assessments, a total of 18 points can be earned.

2018 Long-Term Assessment and Probabilistic Assessment							
	FRCC	**MRO**	**NPCC**	**RF**	**SERC**	**TRE**	**WECC**
Processes in place to validate data	2	2	2	2	3	3	2
Narratives are consistent with submitted data	2	2	2	2	2	2	2
On-time data and narratives	3	3	3	3	3	3	2
Narratives complete and comprehensive	2	2	3	2	2	2	2
Responsive to peer review feedback	3	3	3	3	3	3	3
Responsive to NERC	3	3	3	3	3	3	3
TOTAL	15	15	16	15	16	16	14

Special Reliability Assessments are developed separately from the periodic assessments and they are not scored in the same manner. Since the Special Reliability Assessment targeted a

specific risk (in this case, an assessment on accelerated generation retirement) not every Regional Entity was required to participate in the same manner. The 2018 Special Assessment primarily focused on coal and nuclear retirements in the Midwest and Mid-Atlantic areas.

NERC's 2018 RA oversight concluded that all Regional Entities adequately supported reliability assessments, with opportunities for improvement. In particular, NERC found that Regional Entities should consider conducting their own or leveraging existing study work to support assessments and that the ERO Enterprise as a whole should consider evaluating reliability beyond the peak hour resource adequacy assessment currently performed. Finally, NERC underscored that improvements for on-time submittal would enhance Regional Entity assessment processes. NERC will continue working with Regional Entities to improve ERO Enterprise Reliability Assessments.

V. ADDITIONAL TARGETED AUDITS

NERC conducted an audit of the three Regional Entities that engage in activities outside of § 215 of the FPA of 2005 to gain reasonable assurance that they are properly budgeting, funding, and accounting for such activities separate from the activities that are funded with § 215 assessments. Section 215 accounting is a financial risk per the annual enterprise risk assessment. The three Regional Entities subject to this audit are NPCC, Texas RE, and WECC. For this audit, NERC reviewed the procedures followed by these Regional Entities to account for their §215 and non-statutory activities. NERC conducted its work utilizing professional standards promulgated by the Institute of Internal Auditors. NERC did not find any instances of noncompliance by any of the three Regional Entities.

VI. CONCLUSION

Wherefore, for the foregoing reasons, the ERO Enterprise continues to satisfy statutory and

regulatory criteria for certification. As a result, NERC respectfully requests that the Commission accept this Performance Assessment for the Assessment Period.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston

Nina H. Jenkins-Johnston
Senior Counsel

Lauren Perotti
Senior Counsel

Candice Castaneda
Counsel

North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, DC 20005
(202) 400-3000
(202) 644-8099 – facsimile
nina.johnston@nerc.net
candice.castaneda@nerc.net
lauren.perotti@nerc.net

Counsel for the North American Electric Reliability Corporation

Date: July 22, 2019

FEDERAL ENERGY REGULATORY COMMISSION
DOCKET NO. RR14-___

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

EXHIBIT A

TO

FIVE-YEAR ELECTRIC RELIABILITY ORGANIZATION PERFORMANCE ASSESSMENT REPORT

DISCUSSION OF HOW NERC MEETS THE ERO CERTIFICATION CRITERIA OF 18 C.F.R. § 39.3(b)

JULY 22, 2019

EXHIBIT A

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B. Criterion 2 - The ERO has established rules that assure its independence of users, owners and operators of the BPS while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committees and subordinate organizational structure. 17

C. Criterion 3 - The ERO has established rules that allocate equitably reasonably equitable dues, fees and charges among end users for all statutory activities. 23

D. Criterion 4 - The ERO has established rules that provide fair and impartial procedures for enforcement of Reliability Standards through the imposition of penalties in accordance with 18 C.F.R. § 39.7, including limitations on activities, operations, or other appropriate sanctions or penalties. 24

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EXHIBIT A

I. DISCUSSION OF HOW NERC MEETS THE ERO CERTIFICATION CRITERIA OF 18 C.F.R. § 39.3(b)

A. Criterion 1 - The ERO has the ability to develop and enforce, pursuant to 18 C.F.R. § 39.7, Reliability Standards that provide for an adequate level of reliability of the BPS.

This criterion encompasses two distinct functions of the ERO: (i) the ability to develop Reliability Standards that provide for an adequate level of reliability of the bulk power system ("BPS"); and (ii) the ability to enforce those Reliability Standards.

Development of Reliability Standards

NERC develops Reliability Standards pursuant to § 300 of its Rules of Procedure ("ROP") and its *Standard Processes Manual* ("SPM"), Appendix 3A to the ROP, both of which have been approved by the Commission as ERO Rules.[1] In accordance with § 316 of the ROP, NERC maintains its accreditation as an American National Standards Institute ("ANSI")-accredited standards developer by demonstrating that its SPM meets ANSI's essential requirements for standards development.

The overall purpose of NERC's Reliability Standards development process, as stated in § 301 of the ROP, is to develop and maintain Reliability Standards that apply to BPS users, owners and operators and that enable NERC and the Regional Entities to measure the reliability performance of the users, owners and operators and to hold them accountable for the reliable operation of the BPS. Section 301 of the ROP requires that Reliability Standards developed by NERC must be technically excellent, timely, just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with other applicable standards of governmental authorities.[2]

In Order No. 672 and the ERO Certification Order, the Commission stated that the ERO's Reliability Standards development process must ensure that each Reliability Standard is technically sound; that its operational specifications are designed to achieve a valuable reliability goal; that the standard is clear and unambiguous regarding what is required and who is required to comply; and that there be clear criteria to measure whether an entity is in compliance with the Reliability Standard, so that enforcement can be applied in a consistent and non-preferential

[1] Sections 304 and 308.1 of the ROP specify that "NERC shall develop Reliability Standards in accordance with the NERC *Standard Processes Manual*, which is incorporated into these Rules of Procedure as Appendix 3A." The current version of the SPM is version 4 which became effective March 1, 2019. *N. Am. Elec. Reliability Corp.*, Docket No. RR19-2-000 (March 1, 2019) (delegated letter order).

[2] Section 304 of the ROP sets forth NERC's "Essential Principles for the Development of Reliability Standards." These principles, which include openness, transparency, consensus-building, fair balance of interests, due process and timeliness, are discussed under criterion 5, below.

manner.[3] Consistent with these requirements, § 302 of the ROP specifies the essential attributes of technically excellent Reliability Standards to be developed by NERC.[4] These essential attributes include:[5]

1. **Applicability** — Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the Reliability Standards, with any specific additions or exceptions noted.[6]

2. **Reliability Objectives** — Each Reliability Standard must have a clear statement of purpose that describes how the Reliability Standard contributes to the reliability of the BPS. Section 302.2 of the ROP lists the general objectives for the BPS that provide a foundation for determining the specific objective(s) of each Reliability Standard:[7]

    2.1. **Reliability Planning and Operating Performance** — Bulk Power Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.

    2.2. **Frequency and Voltage Performance** — The frequency and voltage of Bulk Power Systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

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[3] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104 ¶ 31,204 at PP 258, 262, 325, 327, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006). NERC was certified by the Commission as the ERO, pursuant to § 215(c) of the Federal Power Act ("FPA"), by Commission order issued July 20, 2006.*Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062, at PP 239, 241 (2006) (ERO Certification Order).

[4] In the ERO Certification Order, the Commission recognized that NERC's proposed ROP provided that the characteristics for technical excellence of a Reliability Standard must be met for a proposed Reliability Standard to be approved. ERO Certification Order at P 235.

[5] The descriptions of the essential attributes that follow are summaries, not direct quotes from § 302 of the ROP.

[6] The functional classes of entities, or reliability functions, have been developed through NERC's functional model of the BPS, and are defined in its: (i) *Glossary of Terms Used in NERC Reliability Standards*, and (ii) *Statement of Compliance Registry Criteria* which is incorporated into the ROP as Appendix 5B. Currently, the functional classes of entities are: Balancing Authorities, Distribution Providers, Frequency Response Sharing Groups, Generator Operators, Generator Owners, Planning Authorities/Planning Coordinators, Regulation Reserve Sharing Groups, Reliability Coordinators , Reserve Sharing Groups, Resource Planners, Transmission Operators, Transmission Owners, Transmission Planners, and Transmission Service Providers.

[7] In the ERO Certification Order, the Commission recognized that NERC's proposed rules provided that the purpose of a Reliability Standard, or its reliability objective, should derive from one or more of these eight general objectives. ERO Certification Order at P 236.

2.3. **Reliability Information** — Information necessary for the planning and operation of reliable Bulk Power Systems shall be made available to those entities responsible for planning and operating Bulk Power Systems.

2.4. **Emergency Preparation** — Plans for emergency operation and system restoration of Bulk Power Systems shall be developed, coordinated, maintained, and implemented.

2.5. **Communications and Control** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of Bulk Power Systems.

2.6. **Personnel** — Personnel responsible for planning and operating Bulk Power Systems shall be trained and qualified, and shall have responsibility and authority to implement actions.

2.7. **Wide-Area View** — The reliability of Bulk Power Systems shall be assessed, monitored, and maintained on a Wide-Area basis.

2.8. **Security** — Bulk Power Systems shall be protected from malicious physical or cyber attacks.

3. **Performance Requirement or Outcome** — Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable BPS, consistent with good utility practices and the public interest. Each Requirement is not a "lowest common denominator" compromise, but instead shall achieve an objective that is the best approach for BPS reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance Requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by the Requirement. Each performance Requirement shall have one or more associated measures used to objectively evaluate compliance with the Requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations** — Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that field.

6. **Completeness** — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for penalties and sanctions and other ERO and Regional Entity compliance documents, the consequences of violating a Reliability Standard are clearly presented to the entities responsible for complying with the Reliability Standards.

8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of required performance.

9. **Practicality** — Each Reliability Standard shall establish Requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology** — To the extent possible, Reliability Standards shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards development process.[8]

In the ERO Certification Order, the Commission concluded that by specifying the eightgeneral objectives for which a Reliability Standard must be intended, and by incorporating other requirements for Reliability Standards development into the essential attributes of technically excellent Reliability Standards, NERC's ROP satisfied the requirements of Order No. 672 for the ERO's Reliability Standards development process.[9]

The NERC SPM also specifies the performance elements of a Reliability Standard.[10] The requirement that each Reliability Standard contain these elements applies a systematic discipline in the development and revision of standards, in order to produce standards that are measurable, enforceable, and consistent. The SPM allows for a clear statement of the purpose, requirements, measures, and compliance elements associated with each standard. The performance elements of a Reliability Standard, as specified in the SPM § 2.5, are as follows:

- Title: A brief, descriptive phrase identifying the topic of the Reliability Standard.

- Number: A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the Reliability Standards.

[8] In furtherance of the essential attribute of "Consistent Terminology," NERC has developed and maintains the *Glossary of Terms Used in NERC Reliability Standards*, https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf, containing definitions of terms that are used in one or more Reliability Standards.

[9] ERO Certification Order at PP 239, 241.

[10] *See generally* SPM § 2.0.

- Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard.

- Applicability: Identified which entities are assigned reliability requirements. The specific Functional Entities and Facilities to which the Reliability Standard applies.

- Effective Dates: Identification of the date or pre-conditions determining when each Requirement becomes effective in each jurisdiction.

- Requirement: An explicit statement that identifies the Functional Entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement for which compliance is mandatory.

- Compliance Elements: Elements to aid in the administration of ERO compliance monitoring and enforcement responsibilities.

- Measure: Provides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement.

- Violation Risk Factors and Violation Severity Levels: Violation risk factors ("VRFs") and violation severity levels ("VSLs") are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved Reliability Standard. Each requirement in each Reliability Standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NERC staff, at the same time as the associated Reliability Standard, but are not part of the Reliability Standard. The NERC Board of Trustees ("NERC Board") is responsible for approving VRFs and VSLs.

    - Violation Risk Factors: VRFs identify the potential reliability significance of noncompliance with each requirement. Each requirement is assigned a VRF in accordance with the last approved set of VRF criteria.
    - Violation Severity Levels: VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria.

- Version History: The version history is provided for informational purposes and lists information regarding prior versions of Reliability Standards.

- Variance: A Requirement (to be applied in the place of the continent-wide Requirement) that is applicable to a specific geographic area or to a specific set of registered entities.

- Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated Reliability Standard. The Compliance Enforcement Authority [(CEA)] will be NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

The NERC SPM sets forth the detailed process steps for the development and approval of a new Reliability Standard or a revision to an existing standard; the SPM also sets forth the detailed roles of the different persons and groups in in the process.[11] Under the ROP and the SPM, the key groups involved in development of a proposed new Reliability Standard or revision to an existing standard are: (i) the Standards Committee; (ii) the standards authorization request ("SAR") drafting team; (iii) the standard drafting team; and (iv) the Registered Ballot Body ("RBB").

The Standards Committee is an elected body comprised of two members from each segment of the RBB.[12] The Standards Committee, with the assistance and facilitation of the professional staff of the NERC Reliability Standards development program, oversees the overall standards development process. The Standards Committee ensures that standard development teams have the technical resources and capabilities required to develop technically sound standards that will gain industry support. Among other things, the Standards Committee determines whether SARs, and any associated technical information for the development of a standard, submitted by interested persons and entities should be pursued for development, and it appoints members to SAR drafting teams and standard drafting teams.[13] A SAR drafting team is a team of technical experts that, among other responsibilities, assists in refining a SAR and considers and responds to comments.[14] The standard drafting team is a team of technical experts that develops the details of the proposed new or revised Reliability Standard, analyzes results of field tests of the standard (if applicable), and considers and responds to comments.[15] The RBB, which is open to any person or

[11] The ROP also provides for an expedited standards development process in the event an applicable governmental authority directs the development of a Reliability Standard within a certain timeframe. This process is described in § 309.3 of the ROP.

[12] The segment organization of the RBB is set forth in detail in the *Registered Ballot Body Criteria*, Appendix 3D to the ROP.

[13] *See* SPM §§ 3.4 and 3.6.

[14] *See* SPM § 4.2.

[15] SPM § 4.3.

entity and is organized by industry segments, votes on the adoption or rejection of proposed Reliability Standards or revisions to existing standards.[16]

The SPM also specifies roles in the standards development process for the NERC Reliability Standards staff, which is led by the director of standards.[17] Staff provides support to the Standards Committee in managing the Reliability Standards processes and in supporting the work of all drafting teams. More specifically, staff is responsible for ensuring that development and revision of standards is in accordance with the SPM, works to ensure the integrity of the Reliability Standards development process and the consistency of quality and completeness of NERC Reliability Standards, and facilitates all steps in the standards development process.

The NERC standards development process relies on the legal and technical expertise provided by the industry experts comprising the SAR drafting teams and standard drafting teams, the technical and administrative assistance provided by the NERC standards process managers and the NERC standards process staff, and the overall oversight and direction of the Standards Committee. Thus, the NERC standards development process ensures that the essential attributes of technically excellent Reliability Standards, including the accomplishment of one of the eight general reliability objectives specified in §§ 302.2.1 through 302.2.8 of the ROP, are represented in each Reliability Standard that is developed or revised through the process and submitted to the NERC Board and, ultimately, to the Commission for approval.

Over the last decade, NERC has addressed the Commission's directives for new or revised Reliability Standards in Order No. 693.[18] NERC continues to invest significant resources to support its Reliability Standards program. The following table presents the direct budgeted expenses for the Reliability Standards program for 2015-2019:[19]

[16] ROP § 305; SPM §§ 3.2 and 4.7-4.14. Following successful balloting by the ballot pool, a proposed standard is submitted to the NERC Board of Trustees for approval, and if approved by the Board, is filed with the Commission for approval in accordance with § 215(d) of the FPA and 18 C.F.R. § 39.5. NERC Bylaws, Article IX, § 1; ROP §§ 308.2, 308.3, and 309; and SPM at §§ 4.0 and 4.15.

[17] SPM § 3.5; *see also* ROP § 307.

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

[19] *See NERC 2015 Business Plan and Budget* at 44 and Attachment 2 at 1, filed in Docket No. RR14-6-000 on August 22, 2014; *NERC 2016 Business Plan and Budget* at 43 and Attachment 2 at 20;, filed in Docket No. RR15-16-000 on August 24, 2015; *NERC 2017 Business Plan and Budget* at 45 and Attachment 2 at 24, filed in Docket No. RR16-6-000 on August 23, 2016; *NERC 2018 Business Plan and Budget* at 31 and Attachment 2 at 25, filed in Docket No. RR17-7-000 on August 23, 2017; *NERC 2019 Business Plan and Budget,*Attachment 2 at 20, filed in Docket No. RR18-9-000 on August 24, 2018 The amounts cited are direct expenses only and do not include NERC indirect expenses (General and Administrative, Information Technology, Legal and Regulatory, Human Resources, and Finance and Accounting) allocated to the Reliability Standards Program Area.

Year	Amount
2015:	$4,800,751
2016:	$3,888,768
2017	$3,861,666
2018:	$3,332,944
2019:	$3,377,356

The continent-wide Reliability Standards that have been developed by NERC and approved by the Commission cover the full range of reliability objectives specified in § 302 of the ROP:

- Resource and Demand Balancing
- Communications
- Critical Infrastructure Protection
- Emergency Preparedness and Operations
- Facilities Design, Connections and Maintenance
- Interchange Scheduling and Coordination
- Interconnection Reliability Operations and Coordination
- Modeling, Data, and Analysis
- Nuclear
- Personnel Performance, Training and Qualifications
- Protection and Control
- Transmission Operations
- Transmission Planning
- Voltage and Reactive Power

In accordance with the template and performance elements specified in the SPM, each approved Reliability Standard contains the following clearly-identified sections and subsections: (i) Applicability — stating the title of the standard, its identification number, its purpose, the reliability functional entities to which it is applicable, and its effective date; (ii) Requirements; (iii) Measures; (iv) Compliance — stating the entity responsible for monitoring compliance; the compliance monitoring period and reset timeframe; data retention requirements for the registered

entities; and the levels of noncompliance for specified types of violations of the standard; and (v) Regional Variances, if any.

The inclusion of these elements helps to ensure that Reliability Standards clearly state who is responsible for compliance with a Reliability Standard, the Requirements for which compliance is required, and how compliance may be measured by the CEA.

NERC systematically manages the development of new standards and revisions to standards, in areas of highest need and importance, through its rolling three-year *Reliability Standards Development Plan*. The *Reliability Standards Development Plan* identifies and prioritizes the Reliability Standards development projects in the immediate three-year time horizon. The three-year *Reliability Standards Development Plan* is revised annually, based on input from NERC staff, standards grading activities, the standard drafting teams, the NERC technical committees and subgroups, other industry participants, and government authorities. The three-year rolling *Reliability Standards Development Plan*, as revised each year, is submitted to the NERC Board for approval and then filed with the Commission for information. The *Reliability Standards Development Plan 2019-2021* was approved by the NERC Board on November 7, 2018 and recognizes the diligent work over the last few years in transforming the body of NERC Reliability Standards into a mature state while shifting the focus of the standards program to periodic reviews of existing Reliability Standards, addressing Commission directives, emerging risks, and any SARs that are submitted, and implementing the standards grading initiative.[20]

The plan also addresses projects related to the Standards Efficiency Review. In 2018, NERC and industry completed a comprehensive review of the Operations & Planning Reliability Standards to measure their effectiveness and ability to mitigate the risks to the reliability and security of the BPS, compared to the industry burden for their implementation. This review has informed the need to retire or enhance requirements based on operational experience, and included an analysis of reliability risk, particularly emerging risks, and and any identified cost-effective alternatives were considered. NERC is planning a second phase to examine CIP Reliability Standards.

Enforcement of Reliability Standards

NERC's program for monitoring and enforcing compliance with Commission-approved Reliability Standards is implemented through its *Compliance Monitoring and Enforcement Program* ("CMEP") (§ 400 and Appendix 4C to the ROP), its Organization Registration and

[20] The *Reliability Standards Development Plan 2019-2021*, along with previous versions of the plan, are available at http://www.nerc.com/pa/Stand/Pages/ReliabilityStandardsDevelopmentPlan.aspx.[21] The delegation agreements were originally approved by the Commission in an order issued April 19, 2007 (*Order Accepting ERO Compliance Filing, Accepting ERO/Regional Entity Delegation Agreements, and Accepting Regional Entity 2007 Business Plans*, 119 FERC ¶ 61,060 (2007)), subject to various compliance requirements, which have been addressed in subsequent compliance filings and Commission orders. The currently-effective delegation agreements will expire on December 31, 2020.

Certification Programs (§ 500 to the ROP), its *Sanction Guidelines* (Appendix 4B to the ROP), and its delegation agreements with the Regional Entities.[21]

Section 6(a) of NERC's delegation agreements with the Regional Entities specifies that the Regional Entity shall enforce Reliability Standards within its geographic boundaries through the compliance enforcement program set forth in Exhibit D to the agreement, and that the Regional Entity's compliance monitoring and enforcement program meets all applicable requirements of the FPA, Commission Order No. 672, and the Commission's regulations, including, *inter alia*, the requirement for an audit program pursuant to 18 C.F.R. § 39.7(a), the assessment of penalties pursuant to 18 C.F.R. § 39.7(c) through 39.7(g), and the requirements for due process. Additionally, § 6(f) of the delegation agreements requires the Regional Entity to maintain the capability to conduct investigations of potential violations of Reliability Standards and to conduct such investigations in a confidential manner. It also requires the Regional Entity to maintain a program of proactive enforcement audits, including procedures for spot checks of self-reported compliance and periodic audits of all registered entities.

Through the NERC Organization Registration and Certification Programs, NERC and the Regional Entities have identified users, owners, and operators of the BPS that are obligated to comply with Commission-approved NERC Reliability Standards.[22] Section 500 of the ROP governs the registration of users, owners, and operators of the BPS as responsible for compliance with the requirements of Reliability Standards that are applicable to the reliability function for which the entity is registered. The purpose of the NERC Compliance Registry, established pursuant to § 501 of the ROP, is to clearly identify those entities that are responsible for compliance with Reliability Standards. The NERC Compliance Registry identifies the reliability functions to be performed by each organization responsible for meeting the requirements of Reliability Standards. Organizations listed in the NERC Compliance Registry are responsible for knowing the contents of, and complying with, Reliability Standards applicable to the reliability function(s) for which the entity is registered.[23] The criteria upon which users, owners and operators of the BPS will be registered for one or more reliability functions are specified in § 501 of the ROP and in NERC's FERC-approved *Statement of Compliance Registry Criteria* (Appendix 5B to the ROP). The purpose of the *Organization Registration and Certification Manual* (Appendix 5A) is twofold: (i) to define the process utilized in the Organization Registration Program by identifying which functional entities must register as users, owners and operators, and users of the BPS for

[21] The delegation agreements were originally approved by the Commission in an order issued April 19, 2007 (*Order Accepting ERO Compliance Filing, Accepting ERO/Regional Entity Delegation Agreements, and Accepting Regional Entity 2007 Business Plans*, 119 FERC ¶ 61,060 (2007)), subject to various compliance requirements, which have been addressed in subsequent compliance filings and Commission orders. The currently-effective delegation agreements will expire on December 31, 2020.

[22] Section 215(b)(2) of the FPA requires all users, owners and operators of the BPS to comply with Reliability Standards approved by the Commission. Similarly, the Commission's regulations at 18 C.F.R. § 39.2 and § 40.2 require all users, owners, and operators of the BPS to comply with applicable Reliability Standards and applicable rules of the ERO and Regional Entities approved by the Commission.

[23] ROP § 501. The current categories of reliability functional entities are listed in ROP Appendix 5B, *Statement of Compliance Registry Criteria*. *See also supra* n.6.

compliance with Reliability Standards; and (ii) to define the process utilized in the Organization Certification Program for certifying the following entities: Reliability Coordinator, Balancing Authority, and Transmission Operator.

Typically, a user, owner or operator of the BPS is identified, in the first instance, for placement on the NERC Compliance Registry by the Regional Entity in whose territory the user, owner or operator is located. Upon the entity being notified by NERC that it is being placed on the NERC Compliance Registry, the entity may challenge its inclusion on the NERC Compliance Registry by filing a written objection with NERC.[24] If the entity whose registration is at issue does not agree with the initial determination of the NERC-led review panel, the entity may file an appeal with the NERC Board Compliance Committee ("BOTCC").[25] NERC may remove a registered entity from the NERC Compliance Registry for one or more of the reliability functions for which the entity is listed, based on changed circumstances. As of December 31, 2018, there were 1,416 organizations listed on the NERC Compliance Registry, registered for 3,396 reliability functions.

Monitoring and enforcement of compliance with Reliability Standards is conducted primarily by NERC's Regional Entities, pursuant to § 401.4 of the ROP and the delegation agreements between NERC and the Regional Entities. Each Regional Entity is responsible for compliance monitoring and enforcement activities within its regional footprint.[26] The ROP provide for NERC to take responsibility for CMEP activities where a Regional Entity is unable to perform those functions, as well as to be responsible for overseeing the CMEP activities of the Regional Entities.[27] Section 403 of the ROP describes in detail the required attributes of Regional Entity compliance programs, covering compliance program structure, compliance program resources, and compliance program design. Section 403 emphasizes the requirement that the Regional Entity's governance of its compliance program, and its compliance program staff, be independent.[28] Each Regional Entity must develop an annual Regional Entity Compliance and Enforcement Implementation Plan that identifies the regional risk assessment processes and results, Reliability Standards and Requirements associated with regional risk assessment results, the methods to be used by the Regional Entity for reporting, monitoring, evaluating,

[24] A user, owner, or operator of the BPS may be listed on the NERC Compliance Registry for several reliability functions. A registered entity may challenge its listing for one or more of the reliability functions for which it has been registered while accepting its listing for other reliability function(s).

[25] The registration, challenge, and appeal process described in this paragraph is set forth in § 501.1.3 of the ROP as well as Appendix 5A.

[26] ROP § 401.4.

[27] ROP §§ 401.5, 402, and 404. The Commission has also approved the practice of one Regional Entity entering into an agreement with another Regional Entity to administer the compliance processes in the NERC CMEP with respect to the Regional Entities' registered functions. *See, e.g., Order Conditionally Accepting Compliance Monitoring and Enforcement Program Agreements and Revised Delegation Agreements, and Ordering Compliance Filing*, 132 FERC ¶ 61,024 (2010).

[28] ROP §§ 403.1 and 403.6.

and assessing performance criteria and the Regional Entity's Annual Audit Plan.[29] These plans must be developed on an annual basis and submitted to NERC for approval. In its annual Implementation Plan, each Regional Entity must also report to NERC how the Regional Entity carried out its delegated compliance enforcement authority in the previous year, the effectiveness of its CMEP, and changes expected to correct any identified deficiencies.[30]

NERC is required to conduct an audit, at least once every five years, to evaluate how each Regional Entity implements the NERC CMEP.[31] The evaluation is based on the ROP including the NERC CMEP, the delegation agreement with the Regional Entity, the approved Regional Entity annual CMEP Implementation Plans, the required CMEP attributes, and the CMEP procedures. NERC must provide its evaluations to the Commission and other appropriate ERO governmental authorities to demonstrate the effectiveness of each Regional Entity in compliance monitoring and enforcement.[32]

The controlling document for NERC's compliance monitoring and enforcement activities is the Uniform CMEP, Appendix 4C to the ROP. Pursuant to Exhibit D to its delegation agreement with NERC, each Regional Entity has either adopted the Uniform CMEP or a modified version of the CMEP; in the latter case, the modified CMEP, or an enumeration of any deviations in the Regional Entity's CMEP from the uniform CMEP, is included in Exhibit D to the Regional Entity's delegation agreement. All CMEPs have been approved by the Commission.[33]

The NERC CMEP (as well as each of the modified Regional Entity CMEPs) provide for the following compliance monitoring processes: (i) audits of registered entities for compliance with Reliability Standards;[34] (ii) self-certifications by registered entities of their compliance with

[29] ROP § 403.16.

[30] ROP § 403.16.

[31] ROP § 402.1.1.3.

[32] ROP § 402.1.3. The audit procedure for NERC's audits of the Regional Entity CMEPs is contained in *Audit of Regional Entity Compliance Programs*, Appendix 4A to the ROP.

[33] The Commission initially approved the NERC CMEP and modified CMEPs adopted by certain Regional Entities in their respective delegation agreements, subject to various compliance requirements, in its Order issued April 19, 2007. *Order Accepting ERO Compliance Filing, Accepting ERO/Regional Entity Delegation Agreements, and Accepting Regional Entity 2007 Business Plans*, 119 FERC ¶ 61,060 (2007). Subsequent Commission orders have approved modifications to the NERC CMEP and Regional Entity CMEPs (both modifications in response to Commission directives and modifications initiated by NERC and/or Regional Entities). *See, e.g., Order Conditionally Approving Revised Pro Forma Delegation Agreement, Revised Delegation Agreements with Regional Entities, Amendments to Rules of Procedure and Certain Regional Entity Bylaws*, 133 FERC ¶ 61,061 (2010); *Order Conditionally Accepting Compliance Monitoring and Enforcement Program Agreements and Revised Delegation Agreements, and Ordering Compliance Filings*, 132 FERC ¶ 61,024 (2010); *Order Conditionally Approving Revisions to North American Electric Reliability Corporation Rules of Procedure*, 141 FERC ¶ 61,241 (2012).

[34] ROP, Appendix 4C.

standards;[35] (iii) spot checks of registered entities' compliance with Reliability Standards;[36] (iv) compliance investigations ("CIs"), which may be conducted and led by the Regional Entity or by NERC;[37] (v) self-reports by registered entities of violations of Reliability Standards;[38] (vi) self-logging; (vii) periodic data submittals by registered entities as requested by the CEA;[39] (viii) complaints; and (ix) preliminary screens.[40] The NERC CMEP sets forth detailed process steps for each of the seven compliance monitoring methods, including requirements for the results of the processes to be reported by the Regional Entity to NERC and ultimately to the Commission. The NERC CMEP provides for due process for a registered entity by including provisions that address avoidance of conflicts of interest,[41] preservation of confidentiality,[42] provision of notice, and opportunities to respond.[43]

As specified by § 4.1 of the CMEP, NERC develops and posts an annual CMEP Implementation Plan each year which focuses on risks for the upcoming year. The ERO Enterprise has a consolidated Implementation Plan which provides ERO-Enterprise-wide guidance while preserving Regional Entity differences by appending Regional Entity-specific Implementation

[35] ROP, Appendix 4C § 3.2.

[36] ROP, Appendix 4C § 3.3.

[37] ROP, Appendix 4C § 3.4.

[38] ROP, Appendix 4C § 3.5.

[39] ROP, Appendix 4C § 3.6. The CEA is the entity (either NERC or the Regional Entity, as applicable) responsible for monitoring and enforcing the registered entity's compliance with Reliability Standards. CMEP § 1.1.7.

[40] ROP, Appendix 4C § 3.7.

[41] For example, the registered entity is notified in advance of a compliance audit as to the members of the audit team (who are required to be free of conflicts of interest) and their backgrounds and is given the opportunity to object to individual members of the audit team on grounds of a conflict of interest or other circumstance that could interfere with the team member's impartial performance of his or her duties. *See* CMEP § 3.1.5. Similar notice and opportunity to object is provided with respect to spot checking teams (*id*. § 3.3.1) and CI teams (*id*. § 3.4.1). In addition, §6 of the NERC-Regional Entity delegation agreements requires the Regional Entity to maintain a conflict of interest policy that assures the integrity of its compliance enforcement program and the independence of the compliance program staff from those subject to enforcement actions.

[42] ROP, Appendix 4C §§ 2.0 and 9.3. In addition, § 6 of the NERC-Regional Entity delegation agreements specifies that each violation or alleged violation of a Reliability Standard shall be treated as nonpublic until the matter is filed with the Commission as a notice of penalty or resolved by an admission that the owner, operator, or user of the BPS violated a Reliability Standard or by a settlement or other negotiated disposition.

[43] For example, the CEA must notify the registered entity in advance of a compliance audit as to the Reliability Standards to be covered by the audit, and must provide a pre-audit questionnaire to the registered entity at least two months before commencement of the audit. NERC uniform CMEP § 3.1.1. At the conclusion of the audit, the compliance audit team is required to provide a draft audit report to the registered entity for comment. *Id*. § 3.1.6. Similarly, in the spot check and periodic data submittal processes, the CEA is required to provide its draft assessment of compliance to the registered entity for comment. *Id*. §§ 3.3.1 and 3.6.1.

Plans. The Regional Entity-specific Implementation Plans describe risk assessments that identify the risks that the REs will consider as part of their monitoring activities for registered entities..

The NERC CMEP also specifies the processes to be followed when an alleged violation of a Reliability Standard by a registered entity is identified,[44] including notification to the registered entity of an alleged violation and the required contents of the notice;[45] the registered entity's response to the notification of alleged violation;[46] the opportunity for the registered entity to obtain a hearing on the alleged violation and/or proposed penalty or sanction before the CEA hearing body;[47] the process the registered entity may engage in to negotiate a settlement with the CEA;[48] the registered entity's right to appeal a hearing body decision to NERC;[49] and the process for reporting a penalty or sanction to the Commission for confirmation.[50]

The NERC CMEP requires that a registered entity found to be in violation of a Reliability Standard must file a mitigation plan with the CEA to correct the violation, or a description of how the violation has been mitigated.[51] The NERC CMEP describes the required contents of the registered entity's proposed mitigation plan;[52] the processes for submittal of the proposed mitigation plan,[53] for review and acceptance or rejection of the proposed mitigation plan and for review and approval or disapproval by NERC (and, in the latter event, modification of the mitigation plan by the registered entity);[54] the timetable for completion of an accepted mitigation plan;[55] and the process for completion and confirmation by the CEA of implementation of the registered entity's mitigation plan.[56] Key components required by the NERC CMEP to be in any

[44] ROP, Appendix 4C § 5.0.

[45] ROP, Appendix 4C §§ 5.1 and 5.3.

[46] ROP, Appendix 4C § 5.4.

[47] ROP, Appendix 4C § 5.5 and Attachment 2, *Hearing Procedures*. The *Hearing Procedures* set forth the detailed procedures for the hearing to be conducted before the CEA hearing body should a registered entity dispute a notice of alleged violation, proposed penalty or sanction, proposed mitigation plan, or a remedial action directive.

[48] ROP, Appendix 4C § 5.6.

[49] ROP, Appendix 4C § 5.7. The NERC appeal process is addressed in §§ 408 and 409 of the ROP.

[50] ROP, Appendix 4C § 5.9.

[51] ROP, Appendix 4C § 6.1.

[52] ROP, Appendix 4C § 6.2.

[53] ROP, Appendix 4C § 6.4.

[54] ROP, Appendix 4C § 6.5.

[55] ROP, Appendix 4C § 6.3.

[56] ROP, Appendix 4C § 6.6.

mitigation plan are the registered entity's action plans to correct the violation(s) and to prevent recurrence.[57]

Not all instances of noncompliance with Reliability Standards require the same type of processing and documentation as described for violations of Reliability Standards. Noncompliance that does not pose a serious or substantial risk to the reliability of the BPS may be resolved through streamlined processes. The Find, Fix, Track and Report and the Compliance Exception processes were developed as alternatives to the above outlined process.[58]

Additionally, the NERC CMEP provides the procedure for the CEA to issue a remedial action directive to a registered entity.[59] A remedial action directive may be issued, when immediately necessary to protect the reliability of the BPS from an imminent threat, to a registered entity the CEA believes is committing or has committed a violation of a Reliability Standard. The remedial action directive may include, but is not limited to, specifying operating or planning criteria, limits or limitations; requiring specific system studies; defining operating practices or guidelines; requiring confirmation of data, practices or procedures through inspection, testing or other methods; requiring specific training for personnel; requiring development of specific operating plans; directing a registered entity to develop and comply with a plan to remediate a violation; imposing increased auditing or additional training requirements; and requiring the registered entity to cease an activity that may constitute a violation of a Reliability Standard.[60]

As a key component of the enforcement of compliance with mandatory Reliability Standards, a violation of a standard can result in the imposition of a financial penalty or other penalty or sanction on the registered entity. NERC has established, and is applying, rules and procedures for determining the amount of financial penalties, or other penalties or sanctions, to be imposed on registered entities for violations of Reliability Standards. These rules and procedures are embodied in the NERC *Sanction Guidelines*, Appendix 4B to the ROP. The *Sanction Guidelines* must be followed by the Regional Entities in the implementation of their CMEPs.[61] Penalties and sanctions must bear a reasonable relation to the seriousness of the violation and take into consideration timely remedial efforts by the registered entity.[62] NERC's rules and procedures

[57] ROP, Appendix 4C § 6.2.

[58] ROP, Appendix 4C § 3A.0.

[59] ROP, Appendix 4C § 7.0. A remedial action directive is "[a]n action (other than a [p]enalty or sanction) required by a Compliance Enforcement Authority that (1) is to bring a [r]egistered [e]ntity into compliance with a Reliability Standard or to avoid a Reliability Standard violation, and (2) is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat." NERC CMEP § 1.1.27.

[60] ROP, Appendix 4C § 7.0.

[61] ROP §§ 403.14 and 407.

[62] ROP § 401.7.

for determining appropriate penalties and sanctions for violations of Reliability Standards are discussed in greater detail under criterion 4.[63]

In order to carry out their responsibilities to monitor and enforce compliance with Reliability Standards, NERC and the Regional Entities have developed substantial professional staffs for, and are devoting substantial resources to, their CMEP and Organization Registration Programs. The following table shows the expenses and the numbers of full-time equivalent (FTE) staff budgeted by NERC and each Regional Entity in 2014 and in 2019 for the CMEP and registration program functions.[64]

Regional Entity	**2014 Budgeted FTEs**	2019 Budgeted FTEs
NERC	41.28	22.56
FRCC	19.26	12.18
MRO[65]	21.26	32.35
NPCC	16	17
ReliabilityFirst	43	44
SERC	42.50	34
Texas RE	40	35.75
WECC	58	60

Regional Entity	**2014 Total Funding ($)**	**2019 Total Funding ($)**
NERC	15,891,537	11,878,714
FRCC	4,702,351	4,984,329
MRO[66]	6,697,593	10,763,709
NPCC	8,079,371	8,816,687
ReliabilityFirst	13,584,946	16,163,392
SERC	11,875,409	13,373,347

[63] The ERO has established rules that provide fair and impartial procedures for enforcement of Reliability Standards through the imposition of penalties in accordance with 18 C.F.R. § 39.7, including limitations on activities, operations, or other appropriate sanctions or penalties.

[64] *See* 2014 Business Plans and Budgets https://www.nerc.com/gov/bot/FINANCE/Pages/2014RegionalEntityBusinessPlansandBudgets.aspx; https://www.nerc.com/gov/bot/FINANCE/Pages/2019-NERC-Regional-Business-Plans-and-Budget.aspx. *See also* 2019 Business Plans and Budgets https://www.nerc.com/gov/bot/FINANCE/Pages/2019-NERC-Regional-Business-Plans-and-Budget.aspx;https://www.nerc.com/gov/bot/FINANCE/Pages/2019-NERC-Business-Plan-and-Budget.aspx.

[65] The figures for MRO do not include registration as that function is budgeted with Reliability Standards and Certification.

[66] The figures for MRO do not include registration as that function is budgeted with Reliability Standards and Certification.

Texas RE	9,336,233	10,068,946
WECC	14,763,348	14,966,474

B. Criterion 2 - The ERO has established rules that assure its independence of users, owners and operators of the BPS while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organizational structure.

This criterion encompasses three distinct considerations: (i) independence of NERC from users, owners and operators of the BPS; (ii) fair stakeholder representation in the selection of NERC's directors (trustees); and (iii) provision for balanced decision-making in any NERC committee or subordinate organizational structure.

Independence of Users, Owners, and Operators of the BPS

NERC's Bylaws provide that NERC's business and affairs shall be managed by a Board of Trustees.[67] The Bylaws provide that the Board of Trustees shall consist of ten independent trustees plus the President of NERC.[68] The Bylaws define "independent trustee" as follows:

> An independent trustee is a person (i) who is not an officer or employee of the Corporation [i.e., NERC], a member or an officer, director, or employee of a member of the Corporation, or an officer, director, or employee of any entity that would reasonably be perceived as having a direct financial interest in the outcome of board decisions and (ii) who does not have any other relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a trustee. Provided, that upon initial election to the board, an independent trustee shall within ten (10) days terminate any employee, officer, or director position that conflicts with this subparagraph and shall within sixty (60) days terminate any financial interest or other relationship that conflicts with this subparagraph, and prior to such termination shall not participate in discussion of or voting on any matter involving the entity of which the trustee is an employee, officer or director or in which the trustee has the financial interest or other relationship giving rise to the conflict.[69]

[67] NERC Bylaws, Article III § 1.

[68] NERC Bylaws, Article III § 1. On October 14, 2009, the Commission approved in a letter order, in Docket No. RR09-8-000, new §§ 1a and 1b that allows the Board of Trustees to exercise the authority to increase the number of trustees from eleven to twelve, and decrease from twelve to eleven, respectively.

[69] NERC Bylaws, Article III § 3a. The last sentence of § 3a, providing for brief time periods for a newly-elected trustee to terminate any employment, officer or director position or financial interest or other relationship that would prevent the trustee from being independent, is a 2008 amendment to the Bylaws that was approved by the Commission by a letter order issued October 7, 2008 in Docket No. RR08-5-000.

In the *ERO Certification Order*, the Commission found that the NERC Bylaws definition of "independent trustee" was sufficient to provide for independence from users, owners and operators of the BPS, subject to one clarification.[70]

Thus, a NERC trustee cannot be an officer, director, or employee of a member of NERC nor of any other entity that would be perceived as having a direct financial interest in the outcome of board decisions, and may not have any other relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a trustee. The "responsibilities of a trustee" include, among other things, voting on: (i) board approval of proposed Reliability Standards;[71] (ii) board approval of the ROP and amendments to the ROP;[72] and (iii) board approval of NERC and Regional Entity budgets.[73] Committees of the NERC Board, such as the BOTCC, are responsible for decisions such as hearing and deciding challenges by a user, owner or operator of the BPS to placement of the entity on the NERC Compliance Registry,[74] hearing and deciding appeals from a Regional Entity hearing body decision on a registered entity's challenge to a notice of alleged violation of a Reliability Standard and/or proposed penalty or sanction,[75] and approving the imposition of penalties or other sanctions for violations of Reliability Standards on registered entities, including by settlements.

In addition, the NERC *Conflict of Interest and Business Ethics Policy for Trustees, Officers and Employees* specifies that NERC Representatives "shall avoid and refrain from involvement in or situations where there is actually a conflict of interest ("Conflict") . . . [A] Conflict arises where a NERC Representative's personal financial interest is affected or may reasonably appear to be affected by his or her actions or decisions in his or her capacity at NERC." NERC's *Process for Reviewing Conflicts of Interes*t outlines how potential conflicts of interest of the independent

[70] *ERO Certification Order* at P 42. The clarification is that the definition prohibits an independent trustee from having a relationship that would interfere with his or her exercise of independent judgment in carrying out the responsibilities of a trustee, regardless of whether he or she is an officer, director, or employee of an entity with an interest in the outcome of NERC Board of Trustees decisions. NERC confirmed this clarification in a compliance filing dated September 18, 2006, and made a modification, consistent with the clarification, to the definition of "independent trustee" in its Bylaws. *Compliance Filing of the North American Electric Reliability Council and the North American Electric Reliability Corporation Addressing Governance Issues and Request for Expedited Treatment*, Docket No. RR06-1, filed September 18, 2006 (*NERC ERO Governance Compliance Filing*) at 3-4.

[71] NERC Bylaws, Article IX § 1; ROP § 308.2.

[72] NERC Bylaws, Article XI § 2; ROP § 1402.

[73] NERC Bylaws, Article XIII §§ 2, 3, 4, and 5; ROP § 1101. Each of the matters just listed, upon being approved by the NERC Board of Trustees, must then be submitted to the Commission for approval or confirmation. Sections 215(d) and (f) of the FPA and 18 C.F.R. §§ 39.4(b), (c), and (d), and 39.5.

[74] ROP § 501.1.3.

[75] ROP § 409.

trustees, officers and employees are evaluated beginning in December of each calendar year.[76] The *NERC Employee Code of Conduct* mandates an "employee's faithful pursuit of the interests of NERC rather than his or her own financial or other interests of another person or organization." Finally, NERC's *Policy on Reporting Complaints Regarding Accounting and Code of Conduct Matters* prohibits retaliation against any NERC employee who lodges a code of conduct complaint about fraud, unethical business conduct, questionable accounting, problems with internal accounting controls, financial reporting or auditing, violations of NERC's codes of conduct for trustees and employees, or violations of law occurring within NERC.

Fair Stakeholder Representation in the Selection of NERC's Trustees

NERC's Bylaws provide for fair stakeholder representation in the selection of NERC's trustees. Candidates for election as a trustee are selected by a nominating committee. The nominating committee is appointed annually (or more frequently if needed in the event of a special election to fill a board vacancy) by the board. The nominating committee is to consist of those independent trustees whose terms do not expire during the current year and such number of other persons with such qualifications as the board shall specify, including at least three members of the NERC Member Representatives Committee ("MRC").[77] The procedures to be followed by the nominating committee must include a means of permitting members of NERC to recommend to the nominating committee candidates for consideration as nominees for independent trustees.[78] NERC's Bylaws specify that the nominating committee "shall also endeavor to nominate candidates for election to the board consistent with the objectives that the board as an entirety reflects expertise in the areas of technical electric operations and reliability, legal, market, financial, and regulatory matters, and familiarity with regional system operations issues; and reflects geographic diversity."[79]

NERC's Bylaws provide that the independent trustees shall be elected by the NERC MRC, from nominees proposed by the nominating committee. To be elected an independent trustee, a nominee must receive the affirmative vote of two-thirds of the members of the MRC.[80] The MRC

[76] On February 6, 2014, the NERC Board of Trustees approved *Governance Guidelines*, which consolidated NERC's (i) *Conflict of Interest and Business Ethics Policy for Trustees, Officers and Employees* and (ii) *Process for Reviewing Conflicts of Interest* into a single cohesive document.

[77] NERC Bylaws, Article III § 5.

[78] NERC Bylaws, Article III § 5.

[79] NERC Bylaws, Article III § 5.

[80] NERC Bylaws, Article III § 6. The NERC Bylaws also require that the number of trustees from Canada shall not be less than the percentage of the net energy for load ("NEL") of Canada to the total NEL of the United States and Canada, times 11 (or12 if the number of trustees has been increased to twelve pursuant to NERC Bylaws Article III, § 1a), rounded up to the nearest whole number, with the management trustee (i.e., the president of NERC) counted as a trustee from Canada if he or she is a Canadian citizen. NERC Bylaws Article III, § 2a. In the *ERO Certification Order*, the Commission approved this provision as "adequately provid[ing] for an international ERO," stating that "appropriate country representation helps to ensure that the ERO is truly international in addressing Bulk-Power

is comprised of representatives from the various sectors of the NERC membership.[81] As specified by Article II § 4 of the NERC Bylaws, the sectors of the NERC membership are: (i) investor-owned utilities; (ii) state/municipal utilities; (iii) cooperative utilities; (iv) federal or provincial utilities/federal power marketing administrations; (v) transmission-dependent utilities; (vi) merchant electricity generators; (vii) electricity marketers; (viii) large end-use electricity customers; (ix) small end-use electricity customers; (x) independent system operators/regional transmission organizations; (xi) regional entities; and (xii) government representatives.[82] The composition of the MRC, as specified in Article VIII § 2 of the NERC Bylaws, is as follows:

(1) Two representatives from each sector except the government representative sector and the regional entity sector;

(2) Two voting representatives from the regional entity sector, with the remaining members of that sector being non-voting members of the MRC;[83]

(3) The chairman and vice chairman of the MRC;[84]and

(4) Any additional Canadian representatives as are selected pursuant to Article VIII § 4 of the Bylaws;[85] and

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System reliability and considering the concerns of stakeholders in each of the three countries." *ERO Certification Order* at P 47.

[81] Membership in NERC is voluntary and is open to any person or entity that has an interest in the reliable operation of the North American BPS, registers as a member, and complies with the other conditions and obligations of membership specified in the NERC Bylaws (which do not include payment of any membership or initiation dues or fees). NERC Bylaws Article II, § 1. In the *ERO Certification Order*, the Commission stated the availability of membership to any person or entity with an interest in the reliable operation of the North American BPS created an open membership structure that is consistent with the statutory requirement that the ERO establish rules that assure fair stakeholder representation. *ERO Certification Order* at P 54. Each member is assigned to one of the 12 membership sectors of NERC. NERC Bylaws Article II § 4.

[82] Article II § 4a of the NERC Bylaws specifies the types of persons or organizations that would be included in each of the membership sectors.

[83] The representation of Regional Entities in the MRC reflects changes made by NERC to the originally-proposed composition of the MRC in response to concerns expressed by the Commission in P 75 of the *ERO Certification Order*. *See NERC ERO Governance Compliance Filing* at 6-9. The Commission accepted these changes in an Order issued October 30, 2006. The Commission also accepted the overall structure and composition of the MRC in that Order. *North American Electric Reliability Corporation, Order on Petitions for Rehearing and Clarification; Order on Compliance Filing*, 117 FERC ¶ 61,126, at PP 30 and 44 (2006).

[84] The chairman and vice chairman of the MRC are selected annually by majority vote of the members of the MRC, and may not be from the same membership sector. Upon being selected as chairman and vice chairman, these individuals cease to be representatives of the MRC sectors to which they were originally elected, and are thereafter responsible to act in the best interests of the members of NERC as a whole. NERC Bylaws Article VIII, § 5.

[85] Article VIII, § 4 of the Bylaws contains provisions for the election of additional Canadian members to the MRC as and when necessary to ensure that the percentage of Canadian members on the MRC is approximately equal to the

(5) The following representatives of the government representatives sector: two representatives of the United States federal government, one representative of the Canadian federal government, two representatives of state governments, and one representative of a provincial government, all of whom shall be nonvoting members of the MRC except the two representatives of state governments.

The MRC is therefore comprised of 28 voting members when at full complement (or more if the election of additional Canadian members has been necessary in accordance with Article VIII § 4 of the Bylaws). The members of the MRC from each sector are nominated from, and elected by, the NERC members in that sector pursuant to the processes specified in Article VIII § 3 of the NERC Bylaws, which generally call for election of the two candidates from each sector receiving the highest numbers of votes in the sector. The members of the MRC are elected annually (or between annual elections if needed to fill a vacancy).[86]

In summary, NERC's trustees are nominated by a nominating committee comprised of independent trustees whose terms are not expiring, members of the MRC, and possibly others. NERC's trustees are elected by a two-thirds vote of the MRC, which is a committee established pursuant to the Bylaws to fairly represent the sectors of NERC's membership and is open to any person or entity with an interest in reliable operation of the North American BPS. Thus, the NERC Bylaws provide for fair stakeholder representation in the selection of NERC's trustees.

Balanced Decision-Making in any NERC Committee or Subordinate Organizational Structure

NERC's Bylaws authorize the Board of Trustees to create standing committees of NERC and such other committees as the Board deems necessary to carry out the purposes of NERC:

> In addition to those committees specified by these Bylaws, to which the board shall appoint members in accordance with the requirements of these Bylaws, the board may by resolution create standing committees of the Corporation; and may in addition by resolution appoint such other committees as the board deems necessary to carry out the purposes of the Corporation. *The board shall appoint standing committees and other committees of the Corporation that are representative of members, other interested parties and the public, that provide for balanced decision making, and that include persons with outstanding technical knowledge and experience. All appointments of committees of the Corporation shall provide the opportunity for an equitable number of members from the United States and Canada (and from Mexico after the Corporation receives recognition by appropriate governmental authorities in Mexico as its electric reliability*

percentage the NEL of Canada is of the total NEL of the United States and Canada. *See* page 24 below for the definition of NEL.

[86] NERC Bylaws, Article VIII, § 3.

> *organization) to be appointed to each committee in approximate proportion to each country's percentage of the total NEL*. All committees shall have such scope and duties, not inconsistent with law, as are specified in these Bylaws and the Rules of Procedure of the Corporation or otherwise determined by the board.[87]

Section 1300 of the ROP provides additional criteria for the creation and appointment of NERC standing committees. In creating a standing committee, the NERC Board of Trustees must approve the charter of the committee and assign specific authority to each committee necessary to conduct business within its charter.[88] Each committee shall have a defined membership composition that is explained in its charter. The specified committee membership composition can provide for balanced decision-making (i) by providing for representatives from each sector of the NERC membership, or (ii) where sector-based membership will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area, by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in a particular subject area.[89] Committee membership shall also provide the opportunity for an equitable number of members from the United States and Canada, based approximately on proportionate NEL.[90]

The ROP require that committee members shall be selected in a manner that is open, inclusive, and fair.[91] Unless otherwise stated in the ROP or approved by the NERC Board of Trustees, all committee member appointments are to be approved by the board, and committee officers are to be appointed by the Chairman of the Board.[92]

Further, the ROP require that all NERC committees and other subgroups (except for those organized on other than a sector basis because sector representation will not bring together the necessary diversity of opinions, technical knowledge, and experience in a particular subject area)

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[87] NERC Bylaws, Article VII § 1 (emphasis added). "Committees specified by these Bylaws" include the MRC and the Nominating Committee for the NERC Board of Trustees (discussed above under "fair stakeholder representation in the selection of NERC's trustees"), and the Personnel Certification Governance Committee ("PGCC") provided for in Article XII of the Bylaws. The purpose of the PGCC is to provide oversight to the policies and processes used to implement and maintain the integrity and independence of the NERC System Operator Certification Program. NERC Bylaws, Article XII § 1. The members of the PGCC are appointed by the Board from candidates nominated by a nominating task force; nominations and appointments are to take into account the need to include representatives of all geographic regions of North America on the PGCC. *Id*., Article XII §2. In addition to the aforementioned committees, NERC standing committees include the Standards Committee, Compliance and Certification Committee, Critical Infrastructure Protection Committee, Operating Committee, Planning Committee, and the Reliability Issues Steering Committee.

[88] ROP § 1301.

[89] ROP § 1302.

[90] ROP § 1302.

[91] ROP § 1303.

[92] ROP § 1303.

must ensure that *no two stakeholder sectors are able to control the vote on any matter, and no single sector is able to defeat a matter*.[93] Any committees and subgroups organized on other than a membership-sector basis must be reported to the NERC Board of Trustees and the MRC, along with the reason for constituting the committee or subgroup in the manner chosen. The ROP provide that for any committee or subgroup organized on other than a membership-sector basis, a reasonable opportunity for additional participation (as members or observers) shall be provided for sectors not represented on the committee or subgroup (subject to any reasonable restrictions as may be necessary to accomplish the mission of the committee or subgroup).[94] Additionally, a reasonable opportunity must be provided for membership from sectors desiring to participate in any committees and subgroups pertaining to development of, interpretation of, or compliance with Reliability Standards.[95]

The ROP provide that NERC standing committees may appoint subgroups using the same principles as specified in § 1302 of the ROP (summarized in the immediately preceding paragraph).[96]

The provisions of §§ 1301 and 1302 of the ROP regarding committee composition reflect revisions to these provisions that were approved or directed by the Commission in its October 30, 2006 order on the *NERC ERO Governance Compliance Filing*.[97]

The requirement for balanced decision-making is also applicable to the Reliability Standards development process, and is discussed below under criterion 5.,

C. Criterion 3 - The ERO has established rules that allocate equitably reasonable dues, fees and charges among end users for all statutory activities.

NERC's Bylaws require that the funding mechanism used to recover its net annual budget requirement (i.e., net of fees and other revenues received by NERC from users and purchasers of NERC products and services, and net of prior-period funding surplus or deficiency) "shall consist of such assessments as determined by the [NERC] board that result in an equitable allocation of the Corporation's funding requirement among end users of the North American electric utility system as established in the Corporation's Rules of Procedure."[98] Section 1102 of the ROP,

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[93] ROP § 1302.

[94] ROP § 1302.

[95] ROP § 1302.

[96] ROP § 1305.

[97] *See North American Electric Reliability Corporation, Order on Petitions for Rehearing and Clarification; Order on Compliance Filing*, 117 FERC ¶ 61,126, at PP 75-87 (2006).

[98] NERC Bylaws, Article XIII § 3. NERC charges users/purchasers of some of its products and services directly for the products and services, at prices that cover some or all of the cost of providing the product or service. Examples include charges to purchasers of data sets from the Generating Availability Data System, charges to candidates for

"NERC Funding and Cost Allocation," prescribes the allocation methods to be used to recover NERC's funding requirements among regions of the United States and among countries in the North American BPS. Section 1102 specifies that NEL shall be used to allocate funding requirements among interconnections and Regional Entities except in those instances in which direct assignment of costs to a particular interconnection, Regional Entity, or group of entities is appropriate; however, in the case of direct assignment, NEL must be used to allocate the directly-assigned costs within the interconnection, Regional Entity, or group of entities:

> (1) In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on NEL.
>
> (2) NERC's costs shall be allocated so that all load (or, in the case of costs for an Interconnection or Regional Entity, all load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.
>
> (3) Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.
>
> (4) Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on NEL.

The ROP defines NEL as:

> [N]et generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities.[99]

In business plan and budget filings with the Commission, actual assessments for Canadian and Mexican entities vary after taking into account polices regarding the allocation of certain compliance and enforcement costs.

D. Criterion 4 - The ERO has established rules that provide fair and impartial procedures for enforcement of Reliability Standards through the imposition of penalties in accordance with 18 C.F.R. § 39.7, including limitations on activities, operations, or other appropriate sanctions or penalties.

NERC has established rules that provide fair and impartial procedures for monitoring and enforcement of compliance with Reliability Standards. These rules and procedures are embodied

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certification as NERC-certified operators for examinations and for renewal of credentials, and charges to continuing education providers for certification of their education programs.

[99] ROP, Appendix 2.

primarily in § 400 of the ROP, the NERC CMEP (Appendix 4C to the ROP), and individual Regional Entity CMEPs (which conform generally to the NERC CMEP), all of which have been approved by the Commission. These rules and procedures were discussed in detail above under criterion 1, relating to the ERO's ability to develop and enforce Reliability Standards that provide for an adequate level of reliability of the BPS. As discussed above under criterion 1, § 400 of the ROP, and the NERC uniform CMEP, include provisions for avoidance of conflicts of interest on the part of the CEA personnel conducting compliance monitoring processes, provisions for notice to registered entities and opportunity to respond to compliance monitoring processes, and provisions allowing registered entities to engage in settlement discussions with the CEA concerning notices of alleged violations, proposed penalties or sanctions, and mitigation plans.

Each Regional Entity shall adopt either the Regional Entity Hearing Process (ROP § 403.15A) or the Consolidated Hearing Process (ROP § 403.15B) and conduct all hearings pursuant to the selected process. In either case, the selected hearing process shall be a fair, independent, and nondiscriminatory process for hearing contested violations and any Penalties or sanctions levied, in conformance with Attachment 2 (*Hearing Procedures*) to Appendix 4C to theROP. Attachment 2 contains detailed due process procedures for the conduct of hearings before the CEA hearing body, when requested by the registered entity, concerning a disputed notice of alleged violation and/or proposed penalty or sanction, disputed mitigation plan provisions, or disputed remedial action directive. The *Hearing Procedures*, which were initially approved by the Commission in two orders, subject to various specific compliance requirements,[100] are based on, and in most respects are quite similar to, the Commission's Rules of Practice and Procedure[101] and to the rules of practice and procedure used by many state public utility commissions.

Section 215(e)(6) of the FPA, and § 39.7(g) of the Commission's regulations,[102] requires that any penalty imposed for violation of a Reliability Standard shall (a) bear a reasonable relation to the seriousness of the violation; and (b) take into consideration the efforts of the user, owner or operator to remedy the violation in a timely manner.[103] This fundamental requirement is embodied in § 401.7 of the ROP and in § 3.8 of the NERC *Sanction Guidelines*, Appendix 4B to the ROP. Section 39.7(c) of the Commission's regulations[104] requires that NERC or a Regional Entity may, after notice and opportunity for hearing, impose a penalty on a user, owner or operator of the BPS for a violation of a Reliability Standard if NERC files a notice of penalty and record of the proceedings with the Commission and serves a copy on the user, owner or operator. The notice of

[100] *Order Addressing Revised Delegation Agreements*, 122 FERC ¶ 61,245 (2008); *Order Accepting Compliance Filings, Subject to Conditions*, 125 FERC ¶ 61,330 (2008).

[101] 18 C.F.R. Part 385.

[102] 18 C.F.R. § 39.7(g).

[103] 18 C.F.R. § 39.7(g)(1) also specifies that a penalty may be monetary or non-monetary, and may include, but is not limited to, a limitation on an activity, function, operation, or other appropriate sanction, including being added to a reliability watch list composed of major violators that is established by the ERO, a Regional Entity or the Commission.

[104] 18 C.F.R. § 39.7(c).

penalty must contain: (i) the name of the entity on whom the penalty is imposed; (ii) identification of each Reliability Standard violated; (iii) findings of fact with respect to any act or practice resulting in violation of the standard; (iv) a description of the penalty imposed; (v) the record of the proceeding; and (vi) any other matters NERC or the Regional Entity may find relevant.[105] The penalty may not take effect earlier than the 31st day after NERC files the notice of penalty and record of proceeding with the Commission,[106] and it is subject to review by the Commission on its own motion or on application of the user, owner or operator.[107] Section 5.9 of Appendix 4C provides for the filing of a notice of penalty with the Commission, and for a 30-day period to run before the penalty becomes effective, in accordance with 18 C.F.R. § 39.7(d) through (e).[108]

Section 39.7(g) of the Commission's regulations[109] requires the ERO to submit for Commission approval penalty guidelines that set forth a range of penalties for violations of Reliability Standards, and specifies that a penalty imposed by the ERO or a Regional Entity must be within the range set forth in the penalty guidelines. The NERC *Sanction Guidelines* comprise the penalty guidelines established by NERC, which the Commission has approved pursuant to § 39.7(g).

Under the *Sanction Guidelines*, penalties are to be commensurate to the reliability impact of the violation and to those levied for similar violations, while still reflecting unique facts and circumstances related to the violation or the violator. NERC is charged with ensuring "acceptable similarity" in penalties for comparable violations.[110]

Significantly, however, the *Sanction Guidelines* also state, "Any provisions within a settlement regarding Penalties or sanctions can supersede any corresponding Penalties or sanctions that would otherwise be determined pursuant to these Sanction Guidelines."[111] As such, the negotiation of settlements and determination of penalties involve compromise and the weighing of multiple considerations to arrive at a penalty agreeable to the Regional Entity and the registered entity. Even with this available flexibility, NERC still evaluates the facts and circumstances of every violation that is part of a settlement to ensure that the penalty for that violation, and for the group of violations in the settlement, is within a range of reasonableness that displays consistency.

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[105] 18 C.F.R. § 39.7(d).

[106] 18 C.F.R. § 39.7(e).

[107] 18 C.F.R. § 39.7(e).

[108] Certain instances of noncompliance with the Reliability Standards may be resolved outside of the notice of penalty process set forth in the NERC CMEP. *See* NERC ROP, Appendix 4C §§ 3A.0, 5.2A.

[109] 18 C.F.R. § 39.7(g)(2).

[110] *Sanction Guidelines* § 1.

[111] *Sanction Guidelines* § 2.1.

When evaluating every violation, NERC starts with a base penalty amount that is provided by the VRF/VSL matrix. If the registered entity has a previous violation of a same or similar Reliability Standard Requirement, then the penalty may be aggravated.[112] NERC next considers the violation time horizon for the violation, with multipliers applied to the penalty based on the effect on operations. The highest multiplier applies to real-time operations, while long-term planning is on the opposite end of the spectrum. The registered entity's ability to impact reliability determines the next multiplier, with small facilities or entities having their penalty reduced by a significant amount. A multiplier can be applied based on the condition of the BPS at the time of the violation, with aggravation for a violation occurring during stressed conditions.[113] Among the mitigating factors in penalty determination are the quality of the registered entity's internal compliance program, the degree of the registered entity's cooperation in resolution of the violation, and whether the registered entity self-reported the violation.[114]

NERC will aggregate the results of the violation-by-violation analysis for comparison with the penalty included in the settlement submitted by the Regional Entity. NERC also evaluates how the penalty for the violations in the instant settlement compares to penalties for similar violations included in settlements that have already been approved by NERC and subject to review by the Commission. The evaluation of settlements provides an evolving store of knowledge to use when considering new settlements submitted to NERC. In the end, if the penalty included in the settlement falls within a range of reasonableness for penalties associated with violations involving similar reliability risks, similar entities, and similar facts and circumstances, then the penalty is deemed consistent enough for approval by NERC.

E. Criterion 5 - The ERO has established rules that provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing Reliability Standards, and otherwise exercising its duties.

NERC has established rules that provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing Reliability Standards, and otherwise exercising its duties. With respect to the development of Reliability Standards, NERC's Bylaws require that:

> The Corporation shall develop Reliability Standards pursuant to procedures and processes that shall be specified in the Rules of Procedure of the Corporation. The Rules of Procedure shall provide for the development of Reliability Standards through an open, transparent, and public process that provides for reasonable notice and opportunity for public comment, due process, and balancing of interests and is designed to result in Reliability Standards that are technically sound. Participation

[112] *Sanction Guidelines* §§ 3.1 and 3.2.

[113] *Sanction Guidelines* § 2.7; *see also* § 3.2.

[114] *Sanction Guidelines* § 3.3.

> in the process for developing Reliability Standards shall not be limited to members of the Corporation but rather shall be open to all persons and entities with an interest in the reliable operation of the [BPS].[115]

NERC's process for developing and modifying Reliability Standards, which the Commission accepted as meeting the criteria for certifying NERC as the ERO pursuant to § 215 of the FPA and § 39.3(b) of the Commission's regulations,[116] is embodied in § 300 of the NERC ROP and the SPM, Appendix 3A to the ROP. Section 304 of the ROP states that NERC shall develop Reliability Standards in accordance with the NERC SPM. The SPM sets forth the detailed process steps for development and approval of a new Reliability Standards or revision to a Reliability Standard.

Section 304 of the ROP sets forth NERC's "Essential Principles for the Development of Reliability Standards," which include openness, transparency, consensus-building, fair balance of interests, due process, and timeliness:

> 1. **Openness** — Participation shall be open to all persons who are directly and materially affected by the reliability of the North American BPS. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.
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> 2. **Transparency** — The process shall be transparent to the public.
>
> 3. **Consensus-building** — The process shall build and document consensus for each standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.
>
> 4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any two segments as defined in Appendix 3D, *Development of the Registered Ballot Body*, of these Rules of Procedure, and no single segment, individual or organization shall be able to defeat a matter.
>
> 5. **Due Process** — Development of Reliability Standards shall provide reasonable notice and opportunity for any Person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.
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> 6. **Timeliness** — Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the BPS.

[115] NERC Bylaws, Article IX § 2.

[116] *ERO Certification Order* at PP 239, 241, 250.

Section 305 of the ROP specifies that "NERC Reliability Standards shall be approved by a Registered Ballot Body prior to submittal to the [NERC] Board and then to [a]pplicable [g]overnmental [a]uthorities for their approval," and that "[a]ny person or entity may join the Registered Ballot Body to vote on Reliability Standards." The RBB is organized on an industry segment basis, and persons or organizations joining the RBB must select membership in the appropriate segment (subject to periodic review by NERC).[117] The RBB segments and the criteria for membership in each segment are set forth as follows:[118]

- Segment 1: Transmission Owners
- Segment 2: Regional Transmission Organizations and Independent System Operators
- Segment 3: Load-Serving Entities
- Segment 4: Transmission Dependent Utilities
- Segment 5: Electric Generators
- Segment 6: Electricity Brokers, Aggregators, and Marketers
- Segment 7: Large Electricity End Users
- Segment 8: Small Electricity Users
- Segment 9: Federal, State, and Provincial Regulatory or other Government Entities
- Segment 10: Regional Entities

Section 306 of the ROP provides for the standards development process to be overseen by a Standards Committee, which is an elected body comprised of two members of each segment of the RBB and two officers elected to represent the interests of the industry as a whole.[119] The Standards Committee is to ensure stakeholder interests are fairly represented in the Reliability

[117] ROP § 305.

[118] ROP Appendix 3D at 2-3. The segments of the RBB are different from the NERC membership segments established by Article II, § 4 of the NERC Bylaws (discussed above under criterion 2). The Commission approved the use of segments for the RBB that are different from the NERC membership segments. *North American Electric Reliability Corporation, Order on Petitions for Rehearing and Clarification, Order on Compliance Filing*, 117 FERC ¶ 61,126, at P 30 (2006).

[119] Election of the members of the Standards Committee is governed by the *Procedures for Election of Members of the Standards Committee*, Appendix 3B to the ROP.

Standards development process. Section 308.2 of the ROP specifies that proposed Reliability Standards or revisions to Reliability Standards shall be submitted to the NERC Board of Trustees for approval after being approved by the RBB pool voting on the standard.

The NERC SPM sets out the detailed steps in the process for developing and approving Reliability Standards or revisions to Reliability Standards. The process is based on the procedures of the ANSI and other standards-setting organizations in the United States and Canada.[120] The standards development process is intended to develop consensus on both the need for and content of a proposed standard.[121] As detailed in the SPM, the process includes the following key elements:

- Nomination of a proposed standard, revision to a standard, or withdrawal of a standard, using a SAR, which may entail appointing a SAR drafting team.[122]

- Public posting of the SAR to allow interested persons and entities to review and comment on the need for the proposed standard and the expected outcomes and impacts from implementing it, and to identify if there is stakeholder consensus on the need, scope and applicability of the standard proposed by the SAR.[123]

- Review of the public comments in response to the SAR and prioritization of proposed standards, leading to authorization to develop standards for which there is a stakeholder consensus-based need.[124]

- Appointment of a standard drafting team to draft the new or revised standard. The appointed standard drafting team is to have the expertise, competencies and diversity of views needed to develop the standard. The appointment process includes a public solicitation for nominees.[125]

- Drafting the new or revised standard. The standard will be drafted by the standard drafting team with the assistance and administrative support of the NERC standards process manager (a NERC professional staff member), who will review the draft standard for consistency of quality and

[120] SPM §§ 1.4, 10.0, 13.0, and 16.0. ANSI accredited NERC's Reliability Standards development process in 2003.

[121] SPM §§ 1.4. 3.8, 3.10, and 4.0.

[122] SPM §§ 4.0, 4.2, and 4.3.

[123] SPM §§ 4.0, 4.1, and 4.2.

[124] SPM §§ 4.0, 4.1, 4.2, and 4.3.

[125] SPM §§ 4.0, 4.3, and 4.4.

completeness and to ensure the standard is within the scope and purpose identified in the SAR.[126]

- Public posting of the draft standard to allow interested parties to review and comment on it, to receive specific comments from interested parties on the text of the standard, to assess stakeholder consensus on the draft standard, and to determine if the draft standard should be modified to increase consensus.[127]

- Field testing (if any) of the draft standard and its measures.[128]

- Analysis of public comments and field test results (if any) by the standard drafting team, giving consideration to the written views and objections of all participants, to determine if there is consensus the proposed standard should go to ballot, or requires further work.[129]

- Balloting of the standard by the industry stakeholder ballot pool formed from the RBB for purposes of balloting the new or revised standard.[130] (The voting process is described below.)

- Re-balloting of the standard to consider specific comments by those submitting negative votes with comments.[131]

- Vote by the NERC Board of Trustees to approve or reject the standard that has been approved by the ballot pool. The NERC Board of Trustees may adopt or reject a Reliability Standard that has been approved by the ballot pool, but may not modify the standard; however, if the NERC Board of Trustees chooses not to adopt a proposed standard, the board shall provide its reasons.[132]

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[126] SPM §§ 4.0 and 4.4.

[127] SPM §§ 4.0, 4.5, and 4.7.

[128] SPM §§ 4.0 and 6.0.

[129] SPM §§ 4.0, 4.5, 4.6, 4.7, 4.12, and 6.0.

[130] SPM §§ 4.0, 4.7, 4.8, and 4.9.

[131] SPM §§ 4.0, 4.13, and 4.14. Voters on the first ballot are allowed to submit comments with affirmative ballots and reasons for their votes with negative ballots (although inclusion of a statement of reasons with a negative ballot is not required).

[132] SPM §§ 4.0, 4.15, and 4.16.

- Submission of the RBB-approved and board-approved Reliability Standard to the Commission and other applicable governmental authorities for approval.[133]

As provided in the SPM, voting on a proposed Reliability Standard or revision to a standard is done by the RBB ballot pool formed for that standard, and is tallied on a weighted segment basis. At least 30 days prior to the start of a ballot, the NERC standards process manager issues a notice to the entities in the RBB advising them of the upcoming ballot on the new or revised standard, so that entities may elect to join the ballot pool for balloting the standard. Any member of the RBB may join (or leave) the ballot pool for the standard until the ballot period begins.[134] The balloting is conducted electronically with voting allowed during a specified ballot period, typically 10 days.[135] Approval of a proposed standard or revision to a standard requires both (i) a quorum, which is established by at least 75 percent of the members of the ballot pool submitting a response with an affirmative vote, a negative vote, or an abstention,[136] and (ii) affirmative votes by a two-thirds majority of the weighted segment votes.[137] The calculation of the weighted segment voting results is described in detail in the SPM.[138]

The foregoing demonstrates that NERC's rules provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in the development of Reliability Standards. In finding that NERC met the statutory and regulatory criteria to be certified as the ERO, the Commission found NERC's Reliability Standards development process met the ERO certification requirement that the ERO candidate have rules providing for reasonable notice and opportunity for public comment, due process, openness, and balancing of interests in developing Reliability Standards.[139]

Other NERC rules provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in the exercise of NERC's duties other than developing Reliability Standards. As discussed under criterion 2 above, NERC's Bylaws provide for its trustees to be elected by the MRC, which (again per the NERC Bylaws) is comprised of representatives of the sectors of the NERC membership as defined in the Bylaws. The Bylaws also provide that amendments to the Bylaws must be adopted by majority vote of both the Board of Trustees and the MRC, conducted after at least 10 days and no more than 60 days' notice of the

[133] SPM §§ 4.0, 4.16, and 4.17.

[134] SPM § 4.8.

[135] SPM §§ 4.0 and 4.9.

[136] SPM § 4.10.

[137] SPM §§ 4.10 and 4.11. For this purpose the number of votes cast is the sum of the affirmative and negative votes cast by the ballot pool, excluding abstentions, non-responses and negative votes without comments.

[138] SPM §§ 4.10 and 4.11.

[139] *ERO Certification Order* at P 250.

vote on the proposed amendment. Additionally, the NERC membership may adopt new Bylaws, or alter, amend, or repeal amendments adopted by vote of the NERC Board of Trustees and the MRC, by vote of two-thirds of the sectors voting on the alteration, amendment, repeal or adoption.[140]

The NERC Bylaws further provide that revisions to the ROP may be proposed by: (i) any 50 members of NERC, which must include members from at least three membership sectors; (ii) the MRC; (iii) a committee of NERC to whose function and purpose the ROP to be amended pertains; or (iv) an officer of NERC. A proposed revision to the ROP must be posted on the NERC website for public comment for a minimum of 45 days prior to the NERC Board of Trustees vote on the proposed revision.[141]

The NERC Bylaws require that notice of meetings of the NERC Board of Trustees and of the MRC, and notice of calls for action without a meeting by the board or the MRC, along with all non-confidential materials to be considered by the board or MRC at a meeting or in an action without a meeting, shall be posted on the NERC website at least 24 hours prior to the meeting or within 24 hours after the call for action without a meeting.[142] The ROP provide that notice of meetings of NERC committees, and all non-confidential materials relating to the meeting, shall be posted on the NERC website at approximately the same time(s) the notice and materials are provided to the committee members.[143] Additionally, the Bylaws require that, except for discussions of certain specified non-public topics, meetings of the NERC Board of Trustees and of the MRC shall be open to the public (subject to reasonable space limitations).[144] Similarly, the ROP require that, except for discussions of certain specified non-public topics, meetings of NERC standing committees shall be open to the public (subject to reasonable space limitations).[145]

The NERC Bylaws also create an exception to the five day prior notice requirement for Board of Trustee meetings.[146] NERC allows a 24 hour prior notice for special board meetings that are held in closed session. This does not affect the need to provide notice to the public and to members of any meetings, whether closed or open, 24 hours after notice is given to trustees. The shortened notice period permits the Board to address matters that may be considered in closed session in a more timely way when necessary, while not changing the notice provided to stakeholders of any Board meeting.

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[140] NERC Bylaws, Article XIV §1.

[141] NERC Bylaws, Article XI §2.

[142] NERC Bylaws. Article V §§ 4 and 6; Article VIII, §§ 10 and 12.

[143] ROP § 1304.1.

[144] NERC Bylaws, Article V § 4; Article VIII, § 10.

[145] ROP § 1304.1.

[146] NERC Bylaws, Article V § 2.

With respect to the preparation of NERC's annual business plan and budget, the NERC Bylaws provide that NERC shall post a draft business plan and budget for comment by the NERC membership, the MRC, and the NERC standing committees for at least 30 days prior to the board meeting at which the annual business plan, budget and funding requirement is to be approved for submission to the Commission. The Board shall also consult with the members of the MRC on the proposed business plan and budget before it is adopted.[147] Should a supplemental or modified budget or assessment be considered for adoption during the course of the year, the Bylaws require that the procedures for posting, receipt of comments, and consultation with the MRC shall be followed to the extent possible in the board's judgment in light of the exigency of the circumstances necessitating preparation and approval of the supplemental or modified budget, funding and assessment.[148]

With respect to compliance monitoring and enforcement, as discussed above under **Criteria 1** and **4**, the NERC CMEP and Regional Entity CMEPs, the NERC *Hearing Procedures* (Attachment 2 to the CMEP), and the NERC *Sanction Guidelines*, provide for reasonable notice to and due process for users, owners, and operators of the BPS in the conduct of compliance monitoring and enforcement activities of NERC and the Regional Entities. These activities include the implementation of the compliance monitoring processes, the conduct of hearings on disputed notices of alleged violations, proposed penalties, disputed mitigation plan components and disputed remedial action directives, and the imposition of penalties and sanctions for violations of Reliability Standards.

Finally, as discussed above under criterion 2, the NERC Bylaws and ROP require members to be selected for NERC standing committees and other committees and subgroups so as to (subject to specified exceptions) provide for balanced decision making, such that no two stakeholder sectors can control the voting on the committee and no single stakeholder sector is able to defeat a matter; and to provide the opportunity for an equitable number of members from the United States and Canada.

F. Criterion 6 - The ERO has established rules that provide appropriate steps to gain recognition in Canada and Mexico.

To remain certified as the ERO for North America, federal regulations require NERC to take appropriate steps to gain recognition in Canada and Mexico. The efforts of NERC to seek recognition in Canada and Mexico are described below.

Canada

Under the Constitution of Canada, regulation of electricity is primarily within the jurisdiction of each province. Canada does not have a "FERC-equivalent" with plenary jurisdiction over electricity matters, although the National Energy Board ("NEB") does have

[147] NERC Bylaws, Article XIII § 4; *see also* ROP § 1103.1.

[148] NERC Bylaws, Article XIII § 5.

jurisdiction over international power lines. Accordingly, beginning before its certification as the ERO for the United States and continuing to the present time, NERC has devoted significant efforts to developing relationships with each of the relevant provincial authorities, as well as the NEB. Where possible, NERC has devoted efforts attempting to obtain recognition as the ERO. NERC's progress in this regard is described below.

Alberta

Reliability Standards

The Alberta Electric System Operator ("AESO") is the independent system operator, a statutory corporation pursuant to Alberta's *Electric Utilities Act*, *2003* (EUA).[149] AESO's statutory mandate requires that it direct the operation of the Alberta interconnected electric system, plan for the future of the transmission system, and operate the wholesale electricity market in the province.

Pursuant to the Alberta *Transmission Regulation* (made pursuant to the EUA),[150] Alberta Reliability Standards include reliability standards[151] enacted by WECC, NERC, or any similar entity that is recognized by the AESO, to the extent that these reliability standards are adopted by the AESO in accordance with the *Transmission Regulation*. The AESO also has the authority under the *Transmission Regulation* to adopt other reliability standards subject to certain process requirements.

In order for a reliability standard to be adopted in Alberta, the *Transmission Regulation* requires that the AESO consult with those market participants that it considers likely to be directly affected by one or more reliability standards and make a recommendation to the Alberta Utilities Commission to approve or reject the reliability standards being considered for approval. The Alberta Utilities Commission must follow the AESO's recommendation unless an interested person satisfies the Alberta Utilities Commission that the recommendation of the AESO is either "technically deficient" or "not in the public interest." When the AESO considers NERC Reliability Standards for adoption in Alberta, the AESO is required to determine whether the NERC Reliability Standards can be applied in Alberta, including whether approval would be appropriate for the Alberta electric energy market framework.[152]

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[149] Alberta's EUA is available at: http://www.qp.alberta.ca/documents/Acts/E05P1.pdf.

[150] Alberta's *Transmission Regulation* is available at: http://www.qp.alberta.ca/documents/Regs/2007_086.pdf.

[151] In this context, where not capitalized, the phrase "reliability standards" refers to standards relating to reliability generally, whether or not they were developed or approved by NERC.

[152] Alberta has developed an Alberta Functional Model that integrates with the Alberta regulatory and market framework. The Alberta Functional Model defines entity types that perform functions that impact the reliability of the transmission system. Functional entity types are used to identify if an Alberta Reliability Standard is applicable to that functional type.

The AESO's *Alberta Reliability Standards Program Work Plan* is intended to help manage and track the adoption of NERC Reliability Standards in Alberta. It was last revised in June 2014, and it reflects a risk-based prioritization approach.[153] The Alberta Reliability Standards, as approved, bear the same identifiers as the original NERC Reliability Standards (COM, BAL, FAC, etc.), but have an "AB" added to the name.[154]

An Alberta Reliability Standard may incorporate modifications from the original NERC Reliability Standard to recognize the physical characteristics of the Alberta system or for other reasons.[155]

When presented to the Alberta Utilities Commission by the AESO for approval, a proposed Alberta Reliability Standard will contain an explanation for any proposed modifications, which are not intended to change the intent or substance of the NERC Reliability Standards. Where there have been changes from a NERC Reliability Standard to an Alberta Reliability standard, it is noted in a quarterly update report that is provided to WECC and to NERC.

Effective January 1, 2014, the AESO assumed all responsibilities related to the functions of a Reliability Coordinator. Additional Alberta Reliability Standards will be adopted, and this work is underway.

Data Sharing

Under § 8.4 of the WECC/AESO membership and operating agreement ("MOA"), if WECC determines that the AESO is not in compliance with an Alberta Reliability Standard, WECC must promptly refer the matter to the Market Surveillance Administrator ("MSA"). Pursuant to the WECC/MSA services agreement, WECC, on behalf of the MSA, will monitor AESO's compliance with Alberta Reliability Standards and report its findings to the MSA.

Sections 2.13, 6.1, and 6.5 of the WECC/MSA services agreement address WECC's ability to report possible violations[156] to NERC. Under § 2.13, NERC and FERC are not allowed to participate in or observe WECC's actions taken according to the WECC/MSA services agreement, without the express approval of the MSA. Section 6.1 establishes that all records pertaining to

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[153] The *Alberta Reliability Standards Program Work Plan* can be found at: http://www.aeso.ca/rulesprocedures/25052.html. Alberta Reliability Standards currently in effect and their effective dates are listed on the AESO website at: http://www.aeso.ca/rulesprocedures/17006.html. A number of NERC Reliability Standards have been rejected as not being applicable to entities in Alberta. These are listed at: http://www.aeso.ca/rulesprocedures/16426.html.

[154] An example of a current Alberta Reliability Standard is BAL-001-AB-0a, Real Power Balancing Control Performance.

[155] *See* Project Charter for Alberta Reliability Standards Implementation at p.1, http://www.aeso.ca/downloads/ARS_Project_Charter_2011-12-05_final.pdf.

[156] The terms "possible violation," confirmed violation," and "violation" are not defined in Alberta. Rather, Alberta uses the terms "suspected contravention" and "contravention."

WECC's services will be considered confidential and should be treated as strictly confidential at all times.[157]

Based on its agreement with the MSA, WECC is prohibited from disclosing information related to the AESO's compliance with Alberta Reliability Standards without the permission of the MSA. However, as noted in the NERC/WECC/AESO memorandum of understanding ("MOU"),[158] disclosing information related to confirmed contraventions would occur as such information is made public by the Alberta Utilities Commission. In addition, as there is value to the North American electric industry of receiving information on lessons learned from such contraventions, the AESO will work with NERC and WECC to provide information on lessons learned as made public by the Commission.

Compliance

The NERC/WECC/AESO MOU commits the AESO to appropriate compliance monitoring and enforcement "in a manner determined in Alberta." With regard to entities (other than the AESO) that are subject to Alberta Reliability Standards, the AESO carries out its mandate to monitor compliance according to a compliance monitoring plan. Matters of noncompliance with an Alberta Reliability Standard must be referred by the AESO to the MSA for consideration and possible action.

The Alberta Utilities Commission adopted specified penalties for contraventions of Alberta Reliability Standards effective November 2010. If warranted, the MSA is empowered by § 52 of the *Alberta Utilities Commission Act* to issue a notice of specified penalty for contravention of an Alberta Reliability Standard. Specified penalties are defined in AUC Rule 027 and range from $500 to $25,000, depending upon the severity of the contravention and the applicable Alberta Reliability Standard.[159] Specified penalties can be appealed to the Alberta Utilities Commission. Alternatively, the MSA can pursue an administrative penalty before the Alberta Utilities Commission. The maximum administrative penalty amount is $1 million per day on which a contravention occurs or continues.

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[157] Section 6.5 is even more explicit with respect to WECC's authority to share information with NERC and mandates the following:

> WECC further acknowledges that this Agreement clearly stipulates that in no event will Confidential Records received or generated by WECC in respect of the Services or this Agreement be disclosed or made available to persons outside WECC, including to any representative of FERC, NERC or any other person, without the express written approval of the MSA.

[158] MOU between NERC, WECC, and AESO, effective July 15, 2010, at p. 7, http://www.nerc.com/files/NERC-WECC-AESO_MOU_Executed%20Version_071510.pdf.

[159] The specified penalties for contravention of Alberta Reliability Standards are available at http://www.auc.ab.ca/rule-development/rule-027-specified-penalties-for-reliability-standards/Pages/default.aspx.

British Columbia

Reliability Standards

The British Columbia Utilities Commission ("BCUC") is an independent, quasi-judicial regulatory agency that operates under and administers the *Utilities Commission Act*.[160] The BCUC adopts or rejects reliability standards in British Columbia and is responsible for the administration of the Mandatory Reliability Standards Program. The British Columbia Hydro and Power Authority ("BC Hydro"), a provincial crown corporation, is a regulated integrated utility and transmission provider that acts as a balancing authority and applicant for Reliability Standards to the BCUC.

To provide the necessary information required for determinations and in accordance with the *Utilities Commission Act*, BC Hydro submits a *Mandatory Reliability Standard Assessment Report* to the BCUC assessing the new and revised reliability standards adopted in the United States by FERC within the annual assessment period (December 1 to November 30). The purpose of this effort is to examine suitability for application in British Columbia. The assessment report is developed in consultation with Registered Entities in the Mandatory Reliability Standards Program. Further, in consultation with stakeholders regarding the estimated time required for the entities to implement and come into compliance with the reliability standards, BC Hydro suggests effective dates for each of the Reliability Standards assessed. After a public comment process, the BCUC reviews BC Hydro's analysis and then may either approve or reject Reliability Standards. The provincial process can lead to delays before a FERC-approved Reliability Standard is adopted.

In Order G-171-10, issued on November 25, 2010, the BCUC approved an annual Implementation Plan created by WECC for 2011 that includes "a list of minimum [R]eliability [S]tandards to be actively monitored, methods to be used for monitoring, an Audit Plan, Self-Certification Program and Schedule, Periodic Information Submittal requirements and Exception Reporting process."[161] The BCUC has also issued orders approving annual Implementation Plans for subsequent years.[162]

The standards in effect in British Columbia are generally listed in an attachment to the most recent order approving new or amended standards. NERC Reliability Standards and WECC regional Reliability Standards effective in British Columbia are also listed on the WECC website.[163] British Columbia has vested the BCUC with authority to levy monetary penalties for violations. BCUC now has authority to assess fines of up to $1 million per day. The process for imposing penalties for confirmed violations of reliability standards is under development.

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[160] The *Utilities Commission Act*,http://www.bclaws.ca/Recon/document/ID/freeside/00_96473_01.

[161] Order No. G-171-10, issued by the BCUC, at p. 1, http://www.bcuc.com/Documents/Orders/2010/DOC_26511_G-171-10_MRS-2011-Implementation-Plan.pdf.

[162] *See*, e.g., Order No. R-39-13, http://www.bcuc.com/Documents/Orders/2013/DOC_38047_R-39-13_BC-Reliability_2014-Implementation-Plan.pdf (approving the Implementation Plan for the 2014 calendar year).

[163] *See* http://www.wecc.biz/Standards/BCApproved%20Standards/Forms/AllItems.aspx.

In 2018, NERC, BCUC and WECC entered into their first MOU which is intended to supplement and to be read in conjunction with the *Utilities Commission Act*, *Mandatory Reliability Standards Regulation*, and the *Administration Agreement* between BCUC and WECC, dated September 8, 2009, and renewed August 21, 2014, which addresses the development, approval and enforcement of reliability standards applicable to British Columbia.

Data Sharing

WECC's relationship with the BCUC is governed by the *Administration Agreement* between the parties (dated October 8, 2009), the BCUC's *Rules of Procedure for Reliability Standards in British Columbia* ("BCUC ROP"), and BCUC's compliance monitoring program.[164] Under §3.2 of the *Administration Agreement*, WECC is required to immediately advise the BCUC and an applicable entity who has provided information to WECC if that information has been requested by NERC or a foreign government agency, unless disclosure of the request is prohibited by law. Therefore, WECC can only disclose confidential information related to possible violations if the BCUC approves the disclosure or by compulsion of law.

Under § 6.3.1 of the BCUC ROP, the BCUC, in its discretion and upon request, may designate information as restricted.[165] If such designation is made, § 3.6 of the *Administration Agreement* and the BCUC ROP prohibit WECC from transmitting the information outside of British Columbia. WECC can review the restricted information only at the offices of the applicable entity or at the BCUC. The applicable entity is not required to give WECC a copy of the restricted documents.

Under §3.1 of the *Administration Agreement*, WECC shall not disclose such information except as provided in the Rules of Procedure, namely with BCUC approval. Section 3.1.1(ii) also prohibits WECC from disclosing documents or portion of documents that would potentially identify the source of the information. Finally, WECC cannot disclose any information if the BCUC directs WECC to keep it confidential. The MOU does, however, clarify that the signatories of the MOU may share Confidential Information and Non-Public information amongst each other.

Compliance

Under the *Administrative Agreement* with the BCUC, WECC performs compliance oversight for the province, including registration, monitoring and auditing functions and activities. However, the violations, enforcement, and penalty assessment functions remain with BCUC.

Manitoba

Reliability Standards

[164] *See* Attachments 1 and 2 to Order No. G-123-09, issued by the BCUC, available at http://www.bcuc.com/Documents/Orders/2009/DOC_23219_G-123-09_BCUC%20MRS.pdf.

[165] *See* http://www.bcuc.com/Documents/MRS/Rules-of-Procedure.pdf.

The *Manitoba Hydro Act* establishes the framework for Manitoba Hydro to adopt NERC Reliability Standards by authorizing Manitoba Hydro, subject to Lieutenant Governor in Council approval, to adopt:

> in whole or in part, any standards, rules, terms, conditions, guidelines or schedules, which are related to the planning, design or operation of generation or transmission facilities within an integrated regional power grid, established by [the North American Electric Reliability Council, Mid-Continent Area Power Pool or…] an industry organization, regional transmission group, regulatory body or other association or group or any other person.[166]

The *Manitoba Hydro Amendment and Public Utilities Board Amendment Act (Electricity Reliability)*[167] and its implementing regulations, which came into force on April 1, 2012, set the basis for the adoption of mandatory and enforceable NERC Reliability Standards in Manitoba. This legislation gives the Public Utilities Board of Manitoba (PUB) the authority to make determinations of noncompliance with Reliability Standards, to impose sanctions, and to remand a standard to NERC for reconsideration. The enforceable standards in Manitoba are listed in Schedule 1 to the *Reliability Standards Regulation.*[168]

In 2018, Manitoba Hydro, NERC and NPCC entered into an MOU for the limited purpose of Manitoba Hydro and MRO establishing a program for monitoring the compliance of Manitoba entities with reliability standards developed by Manitory Hydro pursuant to *The Manitoba Hydro Act* (C.C.S.M. v. H190).

Compliance

The *Compliance Monitoring and Enforcement Program Province of Manitoba*, based on the NERC CMEP, was adopted as Schedule 2 to the *Reliability Standards Regulation.* MRO and NERC, as compliance bodies, will monitor Manitoba Hydro's compliance with NERC Reliability Standards. If a compliance body alleges that a violation of standards has occurred in Manitoba, it must apply to the PUB with a recommended enforcement action for a determination on whether a standard has been violated. MRO also makes recommendations to PUB regarding the imposition of associated penalties or sanctions. The PUB will decide whether a violation of a standard has taken place and the penalty, if any, which should apply for noncompliance. The PUB can impose a penalty, with enforcement through a board order. When the PUB issues an order confirming a

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[166] *See The Manitoba Hydro Act*, C.C.S.M. c.H190, s.16.3(1)(a), http://web2.gov.mb.ca/laws/statutes/ccsm/h190e.php. The bracketed language above was stricken in *The Manitoba Hydro Amendment and Public Utilities Board Amendment Ac*t (dated June 11, 2009), and replaced with "an industry organization."

[167] Statutes of Manitoba 2009, c. 17.

[168] Available at: http://web2.gov.mb.ca/laws/regs/annual/2014/098.pdf.

violation, NERC may make this fact and any attached penalties public. A similar process is followed for standards develop by Manitoba; however, audit processes and audit reports for Manitoba-developed standards must be maintained separately from audit processes and audit reports prepared for NERC/MRO Reliability Standards.

NERC or MRO, in advising the PUB that they believe a violation has occurred, is also to advise on appropriate remedial actions, sanctions, or penalties.

Data Sharing

All findings by PUB related to electricity reliability proceedings are made public through the issuance of orders. These orders will include the name of the registered entity, the Reliability Standard(s) and requirements(s) violated, whether the PUB agrees with MRO's findings and recommendations, and any penalties or sanctions imposed.

When the PUB issues an order confirming a violation, NERC may make this fact and any attached penalties public. The mitigation plan will not be made public until there is a confirmed violation. Similarly, final audit reports will be released to the public, but only after any alleged violations have become confirmed violations. Lastly, while compliance investigations are confidential, confirmed violations resulting from a compliance investigation will be made public.

For Manitoba-developed standards, all written or verbal information provided by a monitored entity or about a monitored entity, including MRO's and NERC's working papers and documentation are deemed confidential and may be shared between NERC and MRO.

New Brunswick

Reliability Standards

New Brunswick Power Corporation ("NBPC") performs system operation functions. In addition to its responsibility to comply with reliability standards applicable to its function, NBPC is also responsible for making filings to the New Brunswick Energy and Utilities Board ("NBEUB") to update Reliability Standards, maintain a list of BPS elements, and to make recommendations on compliance registrations. NBEUB now also adopts, monitors, and enforces FERC-approved NERC Reliability Standards that have been filed by NBPC. NERC Reliability Standards are filed and adopted with an accompanying NB Appendix to describe the specific application of the standard in New Brunswick. The NBEUB posts proposed Reliability Standards on its website for a 60-day review period prior to adoption. If the proposed Reliability Standard contains substantive revisions to the FERC-approved version, or if there are substantive comments received during the review period, the NBEUB may hold a hearing and may determine to approve, not approve, or remand the proposed Reliability Standard back to NBPC. A list of enforceable Reliability Standards is available on the NBEUB's website.[169] This change is reflected in a new MOU executed in 2016 between NBEUB, NPCC and NERC.

[169] *See* http://www.nbeub.ca/index.php/en/electricity/reliability-compliance/118.

Data Sharing

Confidentiality and public disclosure is governed by Part 7 of the *New Brunswick Compliance Monitoring and Enforcement Program* ("NB CMEP") – Schedule A to the *Reliability Standards Regulation – Electricity Act*.[170] Any information that a registered entity provides to the NBEUB, NPCC, or NERC may be marked as confidential and may not be released to a third party without the written consent of the registered entity. The regulation provides for the public disclosure of finalized audit reports, confirmed violations, penalties, sanctions, and settlement agreements, including the name of the registered entity. The NBEUB is required to keep all CIP information confidential in accordance with § 1500 of the ROP.

Pursuant to the MOU, the parties agree to share Confidential Information and Non-Public Information amongst signatories.

Compliance

The NBEUB implements a compliance monitoring system for reliability standards that is based on the requirements of the NERC compliance program. The NB program is documented as the NB CMEP – Schedule A to the *Reliability Standards Regulation – Electricity Act*. As a recognized compliance body under the regulations, NPCC assists the NBEUB with compliance monitoring activities according to a service agreement the NBEUB has executed with NPCC. The NBEUB will initiate enforcement action if it has reason to believe that a violation of a reliability standard has occurred. NBEUB requires that the entity take action to remove the risk the violation poses to the reliability of the BPS and to implement a plan that will prevent a future occurrence of the violation. Registered entities are subject to financial penalties and sanctions for violations of adopted reliability standards. A penalty matrix, provides ranges for penalties corresponding to VRFs and VSLs, is provided in the *Reliability Standards Regulation*.

Nova Scotia

Reliability Standards

The Nova Scotia Utility and Review Board ("NSUARB") is an independent, quasi-judicial body which exercises general supervision over all electric utilities operating as public utilities within the Province of Nova Scotia, pursuant to the *Nova Scotia Public Utilities Act*.[171] Nova Scotia Power Incorporated ("NPSI") is a public utility in Nova Scotia and is a member of NERC and NPCC. The Nova Scotia Department of Energy is responsible for energy and electricity policy in the province.

[170] New Brunswick's *Reliability Standards Regulation – Electricity Act* is available at http://laws.gnb.ca/en/ShowPdF/cr/2013-66.pdf.

[171] The *Nova Scotia Public Utilities Act*, http://nslegislature.ca/legc/statutes/public%20utilities.pdf.

NERC has signed two separate MOUs with entities in Nova Scotia: one with NSUARB, and one with NSPI.[172]

NERC submits standards to NSUARB and NSPI for approval; each organization may approve, modify, remand or dismiss the standard as not applicable, though final approval authority rests with NSUARB. NSUARB has a quarterly review process allowing the submission, by NERC, of standards already approved by FERC. NSUARB will only process an application after FERC has approved or remanded the Reliability Standard in the United States.[173] NERC made an initial filing of Reliability Standards on June 30, 2010 along with the *Glossary of Terms Used in NERC Reliability Standards*. Nova Scotia approved this filing on July 20, 2011. None of the proposed standards were changed or rejected.

On September 2, 2011, NERC made its first quarterly filing to Nova Scotia that included a list of Standards approved by FERC in the period of time since the June 30, 2011 filing. This filing was approved.

In August 2012, the NSUARB began implementing an expedited process for its review of NERC quarterly filings. With respect to the quarterly filing, NSPI and NPCC have 10 days to comment if they wish. At the end of the comment period, the NSUARB will decide if, based on any comments, a more rigorous review is required. If a more rigorous review is deemed required it will be undertaken; otherwise, the NSUARB will issue its decision. To date, all filings have been approved without additional review.

Under the MOU with NSPI, NSPI agrees to comply with NERC's Reliability Standards. NSPI also committed to review and provide recommendations on the adoption of Reliability Standards in the province to NSUARB.

Data Sharing

The MOU states that NSPI will provide NPCC all information respecting reporting requirements in the CMEP for NERC Reliability Standards.

Under the MOU, NERC has agreed to share relevant information on issues related to reliability compliance with the NSUARB. Examples of such information include:

(1) Compliance audits and spot checks;

(2) Readiness evaluations;

[172] The NSUARB and NERC signed an MOU on December 22, 2006, in which NERC and the NSUARB agreed to a cooperative relationship to improve the reliability of the North American BPS. On May 11, 2010, NERC, NPCC, and NSPI signed an MOU which memorializes the working relationship between the three entities to improve reliability of the grid in Nova Scotia and North America. Both MOUs are available at http://www.nerc.com/filingsorders/ca/pages/canadian-mous.aspx.

[173] The date of the order is considered the effective date for the adopted Reliability Standards.

(3) Disturbance reports;

(4) Reliability assessments and benchmarking information; and

(5) Reports by regional reliability organizations, where applicable.[174]

There is also a data sharing requirement relevant to the Reliability Standards process. The MOU with NSUARB calls for NERC to submit all NERC Board of Trustees-approved Reliability Standards to the NSUARB. NERC also agreed to notify NSUARB immediately if a Reliability Standard has been remanded in another jurisdiction.

Compliance

Compliance is mandatory in Nova Scotia. NPCC is designated to perform compliance and enforcement activities in Nova Scotia upon NPSI, the only entity subject to the NERC Reliabiltiy Standards in Nova Scotia. The NSUARB retains the ultimate authority to determine whether a violation occurred. Penalties are not permitted in Nova Scotia.

Ontario

Reliability Standards

The Ontario Minister of Energy is responsible for the legislation that governs the Ontario Energy Board ("OEB") and the Independent Electricity System Operator ("IESO") and for energy and electricity policy in the province. The IESO of Ontario is a not-for-profit corporate entity established under the Ontario *Electricity Act, 1998*,[175] and is subject to the oversight authority of the OEB. The OEB is responsible for regulating the electricity sector, and it has the legislative authority to stay or revoke the operation of a reliability standard in Ontario and refer it back to NERC or NPCC for further consideration.

On October 25, 2006, the OEB and NERC signed an MOU[176] setting forth the mutual understanding of each party's responsibilities with respect to reliability in the Province of Ontario. The MOU states that Ontario's legislative framework does not expressly contemplate approval of NERC Reliability Standards, By-laws or Rules of Procedure. The MOU recognizes that, under the Ontario Electricity Act, one of the IESO's objectives is to participate in the development of standards relating to the transmission system and to enforce those standards. The MOU confirms that NERC Reliability Standards are referenced generically in the Market Rules written and administered by the IESO, and they are considered in effect in Ontario upon expiration of the

[174] *See* MOU between the NSUARB and NERC at pp. 2-3.

[175] Ontario's *Electricity Act, 1998* is available at http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98e15_e.htm.

[176] Both the 2006 MOU and the 2010 MOU described in the following paragraph are available at http://www.nerc.com/filingsorders/ca/pages/canadian-mous.aspx.

remand period. On November 28, 2006, the Ontario Ministry of Energy formally recognized NERC as the entity named as a "standards authority" in the *Electricity Act, 1998*. Subsequently, in 2008, the *Electricity Act, 1998* was amended, allowing for NPCC to be recognized as a standards authority.

An MOU between the IESO, NPCC, and NERC was signed on November 29, 2006 and amended on February 5, 2010. This MOU documents the roles of the parties in conformance with the Ontario reliability framework and commits the IESO to carry out a compliance enforcement program for Ontario entities. The MOU also acknowledges that the NERC Rules of Procedure have effect in Ontario, provided they do not conflict with the established reliability and compliance framework in Ontario. The amended MOU includes provisions for investigations, organization registration, and NERC certification.[177] The IESO is subject to NERC's CMEP processes in accordance with the MOU. Monitoring and enforcement activities for IESO, with the exception of financial sanctions, are performed by NPCC. The parties contemplate revising this MOU in 2019.

Ontario has a process which provides for market participants, the IESO, or the OEB itself to initiate a review that could result in a standard being remanded or revoked for application in the province. Only Reliability Standards approved by the NERC Board of Trustees on or after May 14, 2008 are subject to this process.

Ontario was the first jurisdiction in North America to adopt NERC Reliability Standards as mandatory and enforceable. Until July 2011, a NERC Reliability Standard became effective on the date specified by the NERC Board of Trustees when it approved the standard. Because of the uncertainties in the timing of FERC approvals, a standard typically came into effect earlier in Ontario than in adjoining U.S. jurisdictions. An Ontario Market Rule amendment effective July 8, 2011 addressed this mismatch. Under this Market Rule,[178] a NERC Reliability Standard will become effective when it is declared mandatory and enforceable in the U.S., unless the OEB remands the Reliability Standard or otherwise stays its enforceability. In addition, any Reliability Standard approved by the NERC Board of Trustees under NERC Rule 321 (i.e., a standard responsive to a regulatory directive that has not been approved by the NERC RBB) must be approved by IESO before it can comes into effect in Ontario.

To date, Ontario has neither remanded nor modified any NERC Reliability Standards. Information regarding Reliability Standards in Ontario can be found on the IESO's website.[179]

Data Sharing

Under the MOU, NERC will provide the OEB with information relevant to Ontario on issues related to compliance with NERC Reliability Standards, including reports on:

[177] In general, such NERC compliance processes do not involve direct participation by Ontario market participants.

[178] *See Market Rules for the Ontario Electricity Market*, ch. 5, Bulk Power System Reliability, available at: http://ieso-public.sharepoint.com/Documents/marketRules/mr_marketRules.pdf.

[179] *See* https://www.ieso.ca/imoweb/ircp/reliabilityStandards.asp.

(1) Compliance audits and spot checks;

(2) Readiness audits;

(3) Disturbance reports;

(4) Reliability assessments and benchmarking information; and

(5) Reports by regional reliability organizations, where applicable.

The MOU also calls for NERC to inform the OEB of Reliability Standards approved by NERC and submitted to appropriate regulatory authorities, and to notify the OEB of NERC Reliability Standards that are remanded to NERC in any jurisdiction outside of Ontario. The MOU states that the IESO is the only Ontario entity directly accountable to NERC for its own compliance and will be accountable to NERC for compliance by all Ontario entities with NERC Reliability Standards.

In the MOU, there is also an undertaking that, subject to confidentiality requirements, the IESO will advise NERC of the functional responsibilities of Ontario entities.

The parties are contemplating updating the MOU in 2019.

Compliance

The MOU stipulates that the IESO is the only Ontario entity that is subject to oversight under NERC's CMEP by NPCC, with the additional caveat that the IESO is not subject to any financial sanctions.

Compliance enforcement within Ontario for the Ontario electricity market participantsnot subject to oversignt by NPCC is conducted by the IESO's Market Assessment and Compliance Division, which is "ring-fenced" from the rest of the organization. The IESO is subject to assessments of compliance with NERC Reliability Standards, including audits performed by NPCC. The completion of mitigation associated with noncompliance is overseen by NPCC as well.

For the remainder of Ontario market participants, the IESO carries out a compliance enforcement program and can issue a monetary order, finding, or remedial action with respect to a violation of a Reliability Standard in Ontario, subject to appeal to the OEB. The IESO has delegated enforcement accountability to the Market Assessment and Compliance Division, which exercises independent discretion in terms of enforcement decision-making.

The Market Assessment and Compliance Division establishes and executes procedures and programs for monitoring, investigating, and imposing sanctions, including financial penalties, against market participants and the IESO itself. The MOU acknowledges the Market Assessment and Compliance Division as the enforcement body in Ontario for Reliability Standards with full sanctioning powers as afforded under the Market Rules for breaches committed by the IESO and Ontario market participants.

In the event that a violation is confirmed under the Market Rules, the name of the responsible entity is made public. The Market Assessment and Compliance Division has the authority to levy sanctions for reliability violations. These sanctions may include financial penalties and are subject to appeal to the OEB. The Market Assessment and Compliance Division has established sanctions guidelines similar to those of NERC using severity/impact criteria. It has authority for "Extraordinary Financial Penalties" under certain circumstances to assess penalties of up to $1 million per occurrence. The OEB can impose administrative penalties of up to $20,000 per day.

Québec

Reliability Standards

The Régie de l'énergie du Québec ("Régie") is an independent agency established under the *Act Respecting the Régie de L'Énergie* ("Régie Act") to regulate the province's electricity and natural gas sectors. On December 8, 2006, NERC and the Régie signed an MOU that contemplated a future amendment to Québec's reliability legislation to grant the Régie the power to adopt and enforce NERC standards and allow for NERC funding and oversight in the province of Québec.[180] The MOU noted that § 73.1 of the Régie Act provides that the "electric power carrier," or Hydro-Québec, will establish reliability standards for its electric power transmission system and submit them to the Régie for approval. According to the MOU, the standards will become mandatory after approval by the Régie.

On December 13, 2006, Québec implemented *An Act Respecting the Implementation of the Québec Energy Strategy and Amending Various Legislative Provisions*,[181] which grants the Régie jurisdiction over a mandatory reliability standards framework in the Province of Québec. This act formalizes the ability of the Régie to approve reliability standards after reviewing an evaluation of the relevance and impact of the proposed standards. Under the act, the Régie may request that the Reliability Coordinator modify a standard or submit a new one. Further, the Reliability Coordinator must submit guidelines to the Régie describing criteria to be taken into account in determining sanctions for noncompliance with reliability standards and identify owners or operators that will be subject to the standards approved by the Régie.

Data Sharing

Under the MOU, NERC has agreed to share relevant information on issues related to reliability compliance with the Régie. The MOU further states NERC will be invited to participate in compliance audits and readiness evaluations done in Québec. Under the MOU, NERC and the Régie also agreed to discuss issues relating to: (i) Reliability Standard approval and remand; (ii) penalties for noncompliance with standards; and (iii) funding. For instance, NERC has agreed to notify the Régie when a new or modified standard is approved in the U.S. or remanded by any other jurisdiction outside of Québec. Additionally, although it is recognized that NERC cannot

[182] Available at http://www.qp.gov.sk.ca/documents/English/Statutes/Statutes/P19.pdf.

[182] Available at http://www.qp.gov.sk.ca/documents/English/Statutes/Statutes/P19.pdf.

impose financial penalties for violations of Reliability Standards in Québec, NERC has agreed to inform the Régie of any violations and of the corresponding amount of penalties associated with such a violation in the United States.

Compliance

The regulatory structure in Québec is governed by Chapter R-6.01, an Act respecting the Régie, a May 8, 2009 MOU between NPCC, the Régie, and NERC, a September 24, 2014 MOU between NPCC, the Régie, and NERC, several Régie decisions, and a Québec specific CMEP ("QCMEP"). Based on these governing documents, NPCC performs compliance and enforcement activities in Québec on all Québec registered entities. The Régie retains the ultimate authority to determine whether a violation occurred. NERC and Québec are contemplating consolidating and updating the MOU and QCMEP agreements into a single agreement in 2019. Under the provincial regime, the Régie may impose, if appropriate, a sanction that may not exceed $500,000 per day and set a deadline for payment.

Saskatchewan

Reliability Standards

Pursuant to *The Power Corporation Act*,[182] Saskatchewan Power Corporation ("SaskPower") has the authority to adopt, set, and administer standards for the planning, design, or operation of transmission lines, equipment, or other facilities within the Saskatchewan integrated regional power grid, and to maintain a membership in an integrated regional power organization. NERC, MRO, and SaskPower entered into an MOU that became effective on February 3, 2009 and was amended on January 15, 2012.[183] The MOU reflects the intent of Saskatchewan to support common North American BPS standards and to describe the protocols to achieve such a goal. For purposes of the MOU, NERC, and MRO are recognized to be Saskatchewan's electric Reliability Standard setting bodies.

In 2015, the parties amended the MOU to reflect SaskPower's Board of Directors creating Saskatchewan Electric Reliability Authority ("SERA") which has the mandate to approve BES standards, to monitor and enforce compliance, and to report to the SaskPower Board of Directors on reliability management. It establishes SERA as the standard setting body as well as the monitoring, compliance and enforcement authority; however, SERA may use MRO, NERC or other resources in exercising its authority.

Reliability Standards approved by the NERC Board of Trustees are automatically adopted in Saskatchewan, unless one of the following two conditions applies. First, if a particular standard has been remanded by any jurisdiction, the Reliability Standard will not be applicable in Saskatchewan. Second, a Reliability Standard will not be applicable in Saskatchewan if is

[182] Available at http://www.qp.gov.sk.ca/documents/English/Statutes/Statutes/P19.pdf.

[183] NERC-Canadian MOUs are available at http://www.nerc.com/filingsorders/ca/pages/canadian-mous.aspx.

remanded, set aside, or a variance has been requested. Under the MOU, once the Reliability Standard is adopted, compliance with the standard is required in Saskatchewan.

Compliance

As mentioned above, SERA has the mandate to monitor and enforce compliance. SERA provides a report on its activities on an annual basis to SaskPower.

National Energy Board

Reliability Standards

NERC and the NEB signed an MOU in 2006. The MOU recognizes NERC as the ERO. In the MOU, NERC and the NEB commit to coordinate in the promotion of a reliable North American BPS.

The NEB regulates the construction and operation of international power lines in accordance with, among other things, the *National Energy Board Act* and the *National Energy Board Electricity Regulations*.[184] The NEB has authority under its legislative framework to take certain enforcement measures in the case of noncompliance to the conditions of a permit or a certificate that was issued for an international power line.

NEB's *General Order MO-036-2012 for Electricity Reliability Standards* and five amending orders for Electricity Reliability Standards in December 2012 (NEB General Order) gave NEB the authority to make Reliability Standards mandatory and enforceable on international power lines.[185]

Data Sharing

NERC and the NEB have committed to exchange experience, information and data relating to the development and compliance with Reliability Standards as applicable to international power lines. The MOU commits NERC to informing and seeking input from the NEB on proposed changes to NERC's Bylaws or ROP. The MOU also commits NERC to inform the NEB when a SAR has been approved and assigned to a drafting team, and to notify NEB when a Reliability Standard is approved.

Under the MOU, NERC commits to notify the NEB at the stage of its development process where the Standards Committee approves a SAR and assigns it for development by a drafting team. The NEB agrees to inform NERC about any changes in its regulatory processes to allow formal approval of NERC Reliability Standards.

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[184] NEB maintains a list of acts and regulations that set forth its mandate, responsibilities, and powers at: http://www.neb-one.gc.ca/clf-nsi/rpblctn/ctsndrgltn/lstctsndrgltn-eng.html.

[185] The NEB General Order is available at: http://www.neb-one.gc.ca/clf-nsi/rpblctn/ctsndrgltn/rrggnmgpnb/lctrcty/lctrcty-eng.html.

Compliance

Consistent with its approach to adopting standards, the NEB has not imposed its own additional compliance monitoring and enforcement regime. The NEB General Order requires international power line permit holders to provide the NEB with certain compliance information, based on the compliance program of the jurisdiction where the international power line is located. In 2012, legislation was passed to provide the NEB with authority to establish a system of Administrative Monetary Penalties (AMP) through regulations in order to promote compliance with the *National Energy Board Act*. The penalties can be up to $100,000 per day for violations levied on companies. Lesser amounts can be levied on individuals. The NEB's regulations on how the AMP would be applied came into force in mid-2013.

There currently is no specific provision that violations would be made public.

Mexico

Baja California

Reliability Standards

In 2013 and 2014, Mexico enacted significant energy reforms that include restructuring of the Mexican electricity industry, increased opportunity for private investment and a competitive electricity market. With these reforms, the roles of several key players in Mexico have changed.

Comisión Reguladora de Energia ("CRE") is the federal energy regulator in Mexico. On March 3, 2016, CRE commissioners approved Resolución RES/151/2016, containing the first Grid Code (Codiga de Red) under Mexico's 2013–2014 electricity reforms. Under these reforms, CRE has many new responsibilities and authorities, including establishing regulations for electric reliability and security. The Grid Code contains the criteria for "efficiency, quality, reliability, continuity, security, and sustainability of the National Electric System" in Mexico, and the initial version incorporates ten NERC Reliability Standards.

CRE is required to update the Grid Code. In June 2016, NERC and WECC conducted a workshop for Mexican subject matter experts to provide a comprehensive overview of NERC and WECC Reliability Standards in order to assist them in providing technical advice to CRE during the development of the second Grid Code. Pursuant to a membership operating agreement between WECC and CFE, WECC has been monitoring CFE's compliance with certain NERC Reliability Standards in the portion of CFE's system in Baja California Norte that is interconnected to California.

Data Sharing

Mexico signed two agreements signifying intent to cooperate with the United States on reliability and participate in the international ERO: a set of bilateral reliability principles between Mexican and U.S. energy officials; and a MOU between NERC, the Mexican Energy Regulatory Commission ("CRE"), and the Mexican electricity system and market operator ("CENACE"). The parties to the MOU agree to share information in furtherance of the activities spelled out in the

MOU which include identifying risks related to critical infrastructure protection, assessing reliability performance and risks, and developing practices and tools for system events.

Compliance

WECC uses a compliance monitoring program to monitor and assess compliance with Mexico Reliability Standards applicable to Designated Entities,[186] consistent with the applicable law of Mexico and relevant agreements. If there is any conflict between the MOA and the CMP, the MOA prevails. WECC and Mexican counterparts are developing an agreement to supersede and replace the MOA under which WECC performs certain functions in Baja California Norte.

WECC does not have enforcement or registration/designation authority for CFE. WECC provides compliance monitoring, reviews mitigation plans and completed mitigation plans, and provides assessment recommendations with respect to alleged violations.

[186] "Designated Entities" are the Mexican equivalent of registered entities in the United States.

FEDERAL ENERGY REGULATORY COMMISSION
DOCKET NO. RR19-___

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

EXHIBIT B

TO

FIVE-YEAR ELECTRIC RELIABILITY ORGANIZATION PERFORMANCE ASSESSMENT REPORT

HOW THE REGIONAL ENTITIES SATISFY THE STATUTORY AND REGULATORY REQUIREMENTS FOR DELEGATION

JULY 22, 2019

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I. INTRODUCTION

NERC is the Electric Reliability Organization ("ERO") certified by the U.S. Federal Energy Regulatory Commission ("FERC" or the "Commission") to develop and enforce mandatory Reliability Standards under § 215 of the Federal Power Act.[1] Under § 215(e)(4) of the Federal Power Act[2] and § 39.8 of FERC's regulations,[3] the ERO is permitted to delegate authority to one or more Regional Entities "for the purpose of proposing Reliability Standards to the [ERO] and enforcing Reliability Standards," provided that certain criteria are met. Consistent with § 39.3 of the Commission's regulations[4] and the Commission's September 16, 2010 Order on NERC's *Three-Year ERO Performance Assessment Report*,[5] this section of NERC's Five-Year Performance Assessment Report demonstrates that each of the Regional Entities has satisfied the relevant statutory and regulatory criteria.

II. BACKGROUND

A. The Regional Delegation Agreements

As provided under the authorities noted above, NERC delegates certain ERO functions to the Regional Entities, including the authority to develop and enforce Reliability Standards subject to NERC oversight, by means of a Regional Delegation Agreement ("RDA") between NERC and each Regional Entity. As a condition of delegation, the RDA requires each Regional Entity to comply with applicable ERO Rules and Reliability Standards. These RDAs, which are periodically revised and renewed, must be approved by the Commission prior to becoming effective.

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1 16 U.S.C. § 824(o) (2018).
2 16 U.S.C. § 824(o)(e)(4).
3 18 C.F.R. § 39.8 (2018).
4 18 C.F.R. § 39.3.
5 *North American Electric Reliability Corporation, Order on the Electric Reliability Organization's Three-Year Performance Assessment*, 132 FERC ¶ 61,217, at P 36 (2010).

In its July 20, 2006 order certifying NERC as the ERO, the Commission accepted NERC's proposed *pro forma* RDA, subject to further modifications to be reflected in the final individual RDAs with the Regional Entities.[6] In April 2007, the Commission approved NERC's RDAs with eight Regional Entities.[7] Since 2007, the Commission has approved revised RDAs between NERC and the Regional Entities, including revisions to the *pro forma* and individual RDAs in 2010[8] and 2015.[9]

From 2007 until 2018, NERC maintained RDAs with the following Regional Entities:

- Florida Reliability Coordinating Council ("FRCC");
- Northeast Power Coordinating Council, Inc. ("NPCC");
- Midwest Reliability Organization ("MRO");
- ReliabilityFirst Corporation ("ReliabilityFirst");
- SERC Reliability Corporation ("SERC");
- Southwest Power Pool Regional Entity ("SPP RE");
- Texas Reliability Entity, Inc. ("Texas RE"); and
- Western Electricity Coordinating Council ("WECC").

In July 2017, NERC and the Southwest Power Pool mutually agreed to terminate the responsibilities of the SPP RE as a Regional Entity. On May 4, 2018, the Commission approved the termination of the SPP RE RDA, proposed transfers of registered entities to the SERC and MRO footprints as of July 1, 2018, and revisions to the SERC and MRO RDAs to reflect the

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[6] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, (ERO Certification Order), *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *order on compliance*, 118 FERC ¶ 61,190, *order on reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[7] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh'g*, 120 FERC ¶ 61,260 (2007).

[8] *North American Electric Reliability Corp.*, 133 FERC ¶ 61,061 (2010), *order denying reh'g*, 134 FERC ¶ 61,179 (2011), *order on compliance filing*, 137 FERC ¶ 61,028 (2011).

[9] *North American Electric Reliability Corp.*, 153 FERC ¶ 61,135 (2015) (approving *pro forma* and individual RDAs, subject to compliance filing) and *North American Electric Reliability Corp.*, Docket No. RR15-12-001 (Mar. 23, 2016) (delegated letter order) (accepting final *pro forma* and individual RDAs) (collectively, "2015 RDA Order").

changed geographic footprints of those Regional Entities.[10] The termination of the SPP RE RDA became effective August 31, 2018.

Similarly, in October 2018, the Florida Reliability Coordinating Council ("FRCC") Board voted to dissolve FRCC RE. On February 27, 2019, NERC, FRCC and SERC filed a joint petition with the Commission for approval of the dissolution of FRCC RE. The petition was approved by the Commission on April 30, 2019, which specified that the registered entities in FRCC were to be transferred to SERC on July 1, 2019, and a complete wind down of FRCC RE on August 31, 2019.[11]

The currently-effective RDAs between NERC and the remaining six Regional Entities are due for renewal by December 31, 2020.

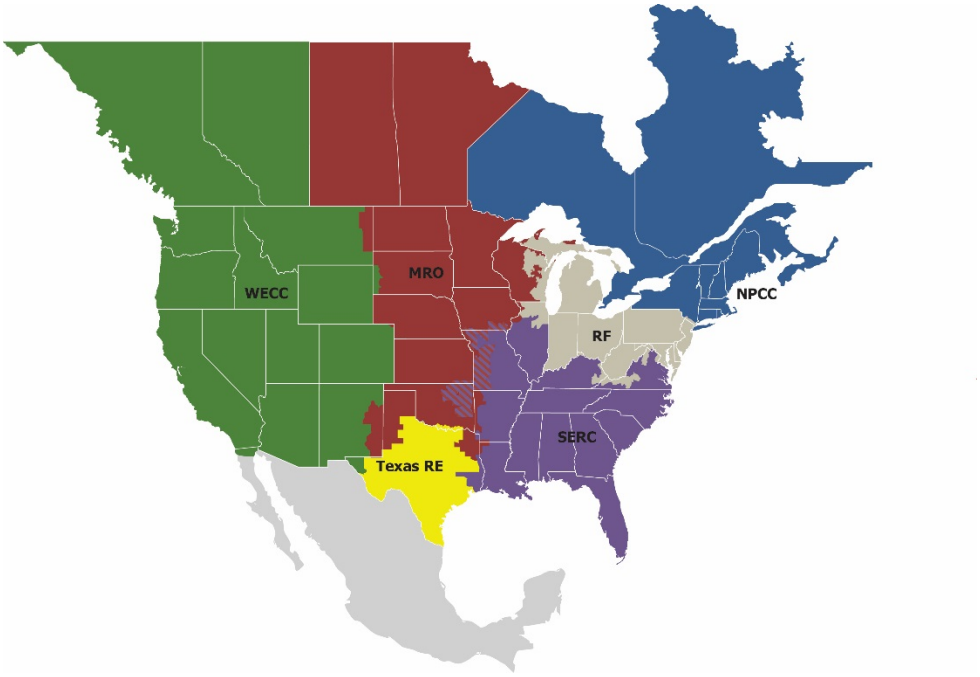
B. Geographic Footprints of the Regional Entities

As shown in **Figure 1** below, the six Regional Entities provide full geographic coverage for the jurisdictional scope of NERC as the ERO for North America.

[10] *North American Electric Reliability Corp., Midwest Reliability Organization, and SERC Reliability Corporation*, 163 FERC ¶ 61,094 (2018).

[11] *North American Electric Reliability Corporation, Florida Reliability Coordinating Council, Inc., SERC Reliability Corporation,* 167 FERC ¶ 61,095 (2019).

Figure 1 — Map of Regional Entities within NERC



C. Statutory and Regulatory Criteria for Delegation

Section 215(e)(4) of the Federal Power Act,[12] as reiterated in § 39.8 of the Commission's regulations,[13] provides that a Regional Entity must satisfy the following criteria to be delegated "authority for the purpose of proposing reliability standards to the ERO and enforcing reliability standards":

1. The Regional Entity is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board.

2. The Regional Entity meets the requirements otherwise applicable to the ERO in § 215(c)(1)(2) of the Federal Power Act,[14] namely that it:

    a. has the ability to develop and enforce reliability standards that provide for an adequate level of reliability of the Bulk-Power system ("BPS"); and

[12] 16 U.S.C. § 824o(e)(4).
[13] 18 C.F.R. § 39.8.
[14] 16 U.S.C. § 824o(c)(1)(2).

b. has established rules that:

i. assure its independence of the users and owners and operators of the BPS, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any committee or subordinate organization structure;

ii. allocate equitably reasonable dues, fees, and other charges among end users for all activities;

iii. provide fair and impartial procedures for enforcement of Reliability Standards through the imposition of penalties;

iv. provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing Reliability Standards and otherwise exercising its duties; and

v. provide for taking appropriate steps to gain recognition in Canada and Mexico.

3. The Regional Entity operates under a delegation agreement that promotes effective and efficient administration of BPS reliability.

During the Assessment Period, each of the Regional Entities has continued to meet the statutory and regulatory criteria to be delegated authority under the RDAs, as discussed in the following section.

III. THE REGIONAL ENTITIES CONTINUE TO SATISFY THE STATUTORY AND REGULATORY CRITERIA FOR DELEGATION

This section provides a description of each of the six[15] Regional Entities and describes in detail how each of these Regional Entities has met and continues to meet the relevant statutory and regulatory criteria.

A. Northeast Power Coordinating Council, Inc. ("NPCC")

NPCC was established as the voluntary, international regional reliability organization for Northeastern North America in January 1966. NPCC is a not-for-profit corporation with a Regional Entity division that performs the statutory functions delegated by NERC and a Criteria

[15] NERC terminated the RDAs with SPP RE and FRCC RE during the Assessment period.

Services division that establishes, monitors, and enforces compliance with regionally-specific criteria. The NPCC geographic region includes the State of New York and the six New England states as well as the Canadian provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia.

NPCC continues to meet the relevant statutory and regulatory criteria for delegation as follows:

1. **NPCC "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board."** NPCC's hybrid board of directors consists of seven stakeholder voting sectors that each consist of a maximum of two directors per sector, an independent sector consisting of two independent directors, an independent board chair with voting rights to preclude board deadlocks, and the President and CEO. Within NPCC, no two sectors can control and no one sector can block action.

2. **NPCC meets the requirements of § 215(c)(1)(2) of the Federal Power Act, because:**

    a. NPCC is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system. NPCC participates in, and supports the development of, all NERC continent-wide Reliability Standards. NPCC also has developed a Regional Standard Processes Manual ("RSPM") that provides the design-basis approach to a consensus building process by which NPCC may develop Regional Reliability Standards and regional variances to be proposed to the ERO for adoption, under delegated authority by the FERC and the Canadian provincial regulatory and/or governmental authorities. This procedure contains common attributes that provide for an adequate level of reliability to provide for an open, balanced, fair, transparent, and inclusive standards development process. NPCC's RSPM sets forth the structure for developing Reliability Standards that provide for an adequate level of reliability. NPCC revised its RSPM for better alignment with the NERC standards development process and NPCC Regional stakeholders' needs. FERC approved the NPCC RSPM on December 23, 2014. In 2018 NPCC has also initiated a revision to the RSPM to identify further opportunities to align the standards development processes with NERC and explicitly clarify the process and authority provided by NERC to develop any further Québec interconnection-wide Variances required for NERC continent-wide standards.

    Illustratively, during the assessment period, NPCC was able to initiate the successful retirement of Regional Reliability Standard PRC-002-NPCC-01 – Disturbance Monitoring. The regional standard was no longer needed to ensure that adequate disturbance data is available to facilitate Bulk Electric System (BES)

event analyses. NPCC participated and led the development of continent-wide Reliability Standard PRC-002-2 Disturbance Monitoring and Reporting Requirements, to facilitate retirement of the regional standard. FERC approved the retirement in a letter order (RD16-8-000) dated August 16, 2016.

In addition, as allowed by the NERC Rules of Procedure, NPCC developed a revision to the Québec variance for Reliability Standard NERC PRC-006-3 - Automatic Underfrequency Load Shedding. The Québec Interconnection-wide Variance was developed in accordance with the NPCC RSPM and approved by the NPCC Board of Directors on May 13, 2017 and the NERC Board of Trustees on August 10, 2017.

NPCC is also engaged in a revision of the Regional Reliability Standard, PRC-006-2 Automatic Underfrequency Load Shedding ("UFLS"). The revision is necessary to remove redundancies with the latest version of the continent-wide Reliability Standard PRC-006-3 and will incorporate the Regional Reliability Criteria contained in Directory 12, allowing retirement of that Directory. The revision will enhance the efficient completion of UFLS studies within NPCC and clarify BES system performance and UFLS program requirements.

Compliance and enforcement activities are carried out by the NPCC compliance and enforcement staff and are independent of all users, owners and operators of the North American BPS. Compliance and enforcement activities are governed in the U.S. by the RDA between NERC and NPCC, delegating portions of NERC's authority as the ERO to NPCC.

NPCC has the requisite compliance and enforcement staff to identify users, owners and operators of the bulk electric system and to monitor and enforce the Reliability Standards. NPCC's compliance staff is divided into four sub-program areas: (i) Compliance Implementation, Registration, and Certification; (ii) Compliance Entity Risk Assessment; (iii) Compliance Monitoring; and (iv) Compliance Enforcement. Compliance Implementation, Registration, and Certification personnel carry out the entity registration and certification activities, administer the compliance tools and portals, and perform entity outreach and education. The Entity Risk Assessment conducts IRAs and ICEs, assists with the development of annual implementation plans, and provides the basis for each registered entity's COP. Compliance Monitoring conducts all compliance monitoring activities to oversee compliance with the NERC Reliability Standards. Monitoring activities include audits, spot checks, and self-certifications. Enforcement determines the relevant facts and circumstances, evaluates the risk, evaluates mitigation, assesses compliance history, determines a disposition method for each noncompliance, and determines penalty sanctions in consistent fashion. When necessary, enforcement works with the registered entity on understanding the noncompliance, determining the root cause, and appropriately mitigating the noncompliance.

b. NPCC has established rules that:

i. **Assure its independence of the users and owners and operators of the BPS, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure.** The rules and procedures contained in the RDA, Rules of Procedure, amended and restated NPCC bylaws, and other NPCC committee governance documents assure the independence of the users and owners and operators of the BPS while assuring fair stakeholder representation and balanced decision-making at the same time. Fair stakeholder representation and participation is assured by NPCC's committees, subcommittees, task forces and other groups as the board of directors may deem appropriate. Industry technical experts from within the membership also provide valuable input to the board through various working groups and task forces as well as the committees.

ii. **Allocate equitably reasonable dues, fees, and other charges among end users for all activities.** The allocation of dues, fees, and other charges by NPCC is governed by Article XIII of its bylaws. Funding of Regional Entity division activities are undertaken pursuant to § 215 of the Federal Power Act in accordance with the funding provisions and procedures of that law and related FERC regulations and orders. After review and endorsement by the NPCC Finance and Audit Committee, the NPCC Board of Directors approves the annual Business Plan and Budget in time for submission to the ERO and to FERC for approval. NPCC funds reliability activities in Canadian provinces pursuant to the mechanisms established by the applicable Canadian provincial regulatory authority. Budgets for the costs of reliability activities are allocated equitably based on the NEL and other relevant factors consistent with applicable law, the RDA, and any agreements with Canadian provincial authorities. NPCC members are not assessed an annual membership fee. For NPCC's Criteria Services division, which establishes and monitors regional-specific non-statutory criteria, Full Members that perform the Balancing Authority function are assessed and pay based upon NEL. Special assessments for Criteria Services may be separately budgeted to Full Members that perform the Balancing Authority function or upon Full Members with Full Members' consent.

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties**. The NERC ROP is the primary document that NPCC uses to guide its fair and impartial procedures for enforcement. With respect to penalties, NPCC consistently uses the NERC provided penalty calculator tool for consistency in penalty calculation determinations. NPCC has in place a *Conflict of Interest Policy* that requires each NPCC director, officer, and employee to avoid and refrain from involvement in situation where there is an actual conflict of interest, annually disclose any actual or potential conflicts of interest that may arise, recuse himself or herself from participation in any action involving an actual

or potential conflict of interest, and refrain from voting on any actions where there is an actual or potential conflict of interest. In addition, NPCC's *Code of Conduct*, which applies to its officers, board of directors, employees, and all participants of NPCC committees, task forces, and working groups, requires each individual to recognize conflicts of interest that may arise and to take steps to disclose such conflicts of interest and to refrain from voting and/or influencing others with respect to such conflicts of interest.

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties.** NPCC follows a RSPM that provides that participation in the development of a Regional Reliability Standard shall be open to all organizations that are directly and materially affected by the NPCC BPS reliability, that there shall be no undue financial barriers to participation, and that participation shall not be conditioned upon membership in NPCC or unreasonably restricted on the basis of technical qualifications or other such requirements. Meetings of drafting teams are open to the NPCC members and others.

Compliance and enforcement activities are carried out by the NPCC compliance staff and are independent of all users, owners and operators of the North American BPS. Compliance and enforcement activities are governed in the U.S. by the RDA between NERC and NPCC, delegating portions of NERC's authority as the ERO to NPCC. In August 2018, NPCC notified NERC that it elected to conduct all hearings pursuant to NERC's consolidated hearing process.

v. **Provide for taking appropriate steps to gain recognition in Canada and Mexico**. There are various regulatory structures in which NPCC is recognized in the Northeastern Canadian provinces of New Brunswick, Nova Scotia, Ontario, and Québec

New Brunswick – Through the New Brunswick Electricity Act and implementing regulations, NPCC is designated as a Compliance Body within New Brunswick. On August 10, 2016, as contemplated in the NB Electricity Act, NPCC and the New Brunswick Energy and Utilities Board ("NBEUB") updated and renewed a Service Contract whereby NPCC provides compliance monitoring and enforcement activities and other services for the NBEUB. Additionally, the NBEUB, NPCC, and NERC entered into a Memorandum of Understanding ("MOU") on August 10, 2016, which describes the roles and responsibilities of the three entities and facilitates data sharing. These two documents, along with the NB Electricity Act, are the governing documents with respect to conducting CMEP and other reliability related activities in New Brunswick. Based on these governing documents, NPCC performs compliance and enforcement activities in New Brunswick on all New Brunswick registered entities. The

NBEUB retains the ultimate authority to determine whether a violation occurred.

Nova Scotia – The regulatory structure in Nova Scotia is based upon a May 9, 2010 MOU between NPCC, Nova Scotia Power, Inc.("NPSI"), and NERC and a July 2011 Order from the Nova Scotia Utility and Review Board ("NSUARB"). Based on these governing documents, NPCC is designated to perform compliance and enforcement activities in Nova Scotia upon NPSI. The NSUARB retains the ultimate authority to determine whether a violation occurred.

Ontario – The regulatory structure in Ontario stems from the Ontario Electricity Act, the Independent Electricity System Operator ("IESO") Market Rules, and a February 5, 2010 MOU between NPCC, the IESO, and NERC. In Ontario, the IESO is the subject to the NERC Reliability Standards through NPCC. NPCC performs compliance and enforcement activities on the IESO.

Québec – The regulatory structure in Québec is governed by Chapter R-6.01, an Act respecting the Régie de l'énergie ("Régie"), a May 8, 2009 MOU between NPCC, the Régie, and NERC, a September 24, 2014 MOU between NPCC, the Régie, and NERC, several Régie decisions, and a Québec specific CMEP ("QCMEP"). Based on these governing documents, NPCC performs compliance and enforcement activities in Québec on all Québec registered entities. The Régie retains the ultimate authority to determine whether a violation occurred.

NPCC has also testified before the Régie in regulatory proceedings related to the designation of the Reliability Coordinator for Québec.

3. **NPCC operates under a delegation agreement that promotes effective and efficient administration of BPS reliability.** On November 2, 2015,[16] the Commission approved the amended and restated NPCC RDA which incorporated benefits of NERC's and NPCC's mutual experience and lessons learned while operating under the predecessor agreement. The revised RDA provides for more efficient and effective execution of responsibilities that promote the reliability of the BPS. These responsibilities include: (i) development and proposal of Reliability Standards; (ii) enforcement of compliance with Reliability Standards; (iii) certification of BPS entities; (iv) registration of owners, operators, and users of the BPS; (v) reliability assessment and performance analysis; (vi) event analysis and reliability improvement; (vii) training and education; and (viii) situation awareness and infrastructure security.

[16] 2015 RDA Order, *supra* n.9.

B. Midwest Reliability Organization ("MRO")

MRO was formed from the former Mid-Continent Area Power Pool Regional council and a portion of Mid-America Interpool Network as a new corporation for the purpose of becoming a Regional Entity under the Energy Policy Act of 2005 and the Bilateral Principles. The region now spans all or part of 16 states and two Canadian provinces. MRO's bylaws provide for members from the following industry sectors: transmission system operators, generators and power marketers, municipal utilities, cooperatives, investor-owned utilities, federal power marketing agency, and Canadian utilities. MRO's bylaws also allow for adjunct members that are not eligible to belong to an industry sector and have a material interest in reliability issues in the MRO region. Membership is at no cost. MRO is independent of all BPS owners, operators, and users, and has no shared employees with any third party. MRO performs only responsibilities delegated from the ERO and similar functions in the Canadian provinces of Saskatchewan and Manitoba. MRO's board of directors ("MRO Board") represents a hybrid governance structure with both independent and stakeholder directors. Currently, MRO's hybrid board consists of 23 directors. Seventeen directors are elected by and represent the industry sectors noted above. Two directors are nominated by the board and elected by all Members to serve as regional directors. A regional director is an employee of a Member and meets the qualifications for directors elected from an Industry Sector. Four independent directors are elected by all Members. On June 4, 2018, NERC filed a petition with FERC for approval of MRO's amended bylaws, under which MRO would add four board positions consisting of two independent directors and two regional directors.[17] MRO's hybrid board is structured so that no two sectors can control a vote. The MRO Board has adopted

[17] *Petition of the North American Electric Reliability Corporation for Approval for Amendments to Midwest Reliability Organization Bylaws*, Docket No. RR18-8-000 (Jun. 4, 2018).

procedures to ensure that it carries out its responsibilities in a non-discriminatory manner, free of conflicts.

MRO continues to meet the relevant statutory and regulatory criteria for delegation as follows:

1. **MRO "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board."** Throughout the five-year assessment period, MRO was governed by a combination independent and balanced stakeholder board.

2. **MRO meets the requirements of § 215(c)(1)(2) of the Federal Power Act, because:**

    a. **MRO is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system.** MRO has a Regional Reliability Standards Process Manual ("RRSPM") and a stakeholder CMEP Advisory Council comprised of subject matter experts is available to fulfill its obligation to develop a regional standard should there be a need for a regional Reliability Standard in the future.

    MRO also has the requisite staff both in terms of number of people and expertise, and adequate processes and procedures, to enforce the Reliability Standards. MRO splits the CMEP function into three distinct steps with their own assigned personnel— (i) Compliance Monitoring, (ii) Risk Assessment and Mitigation, and (iii) Enforcement. Compliance Monitoring staff develops compliance oversight plans and conducts monitoring activities to oversee compliance with reliability standards by registered entities. Risk Assessment and Mitigation staff conduct inherent risk assessments (IRAs) for registered entities, and complete risk determinations for each noncompliance, which includes an independent review of the facts and circumstances. Risk Assessment and Mitigation staff also works with the registered entities to develop effective and comprehensive mitigation. Enforcement staff review recommendations made by Risk Assessment and Mitigation staff, verify all relevant facts, and resolve noncompliances through appropriate processing methods.

    The factual review conducted by the Risk Assessment and Mitigation and Enforcement staff is intended to ensure a consistent, accurate application of the NERC reliability standards. The three-step process also provides for segregation of duties, establishing independence among those making the findings, those assessing risk, and those determining and negotiating penalties and sanctions. As a result of this approach, registered entities in the MRO region accept responsibility for roughly 95% of all noncompliance.

b. MRO has established rules that:

i. **Assure its independence of the users and owners and operators of the** BPS**, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure.** In particular, MRO assures the independence of the users and owners and operators of the BPS by establishing processes and procedures for the conduct of its work. For example, by having a three-step process to implement the CMEP, MRO assures that its internal work is subjected to review and validation. MRO also has specific policies that prevent stakeholder conflicts of interest and prevent stakeholders from participating in its CMEP work. In addition, all MRO members elect the two Regional Directors and four Independent Directors; the remaining directors are elected by industry sectors.

ii. Allocate equitably reasonable dues, fees, and other charges among end users for all activities. MRO's funding requirements are equitably allocated in a manner similar to the one used by the other Regional Entities. Each year, MRO develops an annual business plan and budget that describes in detail the resources MRO needs to carry out its delegated functions. The annual business plan and budget is reviewed and approved by the MRO Board and then submitted to NERC and ultimately filed with the Commission for approval. Assessments are made to MRO's LSEs through a formula which is based on NEL. MRO does not charge additional fees to be a member or to participate in its training. The annual business plan and budget as well as annual audits by independent auditors and periodic audits by FERC help ensure that MRO's expenses and assessments to end users are reasonable.

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties**. To ensure fair and impartial procedures, as described above, MRO has implemented a three-step approach to fulfill its delegated responsibilities under the CMEP. Risk and Mitigation staff completes a risk determination for each noncompliance based on an independent analysis of the unique facts and circumstances. MRO Enforcement staff reviews any recommendations from MRO Risk Assessment and Mitigation staff, verifying that all relevant facts have been gathered, and evaluates the noncompliance for the appropriate enforcement action and penalty, if any.

Assessment of a penalty is reserved for noncompliances that pose greater risk to the reliability of the bulk power system. As a result of the extensive risk assessment conducted by MRO Risk Assessment and Mitigation staff, Enforcement is able to make fair, accurate and reasonable enforcement decisions considering the facts and circumstances coupled with the risk

posed by the noncompliance – the greater the risk, the greater the potential for penalty and scrutiny of review and approval.

In addition, MRO has policies and procedures to avoid conflicts of interest in its CMEP work. Those policies and procedures provide:

(1) MRO's President and CEO and MRO board members do not directly participate in compliance violation investigations, compliance audits, reports, sanction determinations, or other matters within the CMEP.

(2) A MRO director or member of an MRO organizational group may engage in actions on behalf of his or her employer regarding a compliance monitoring and enforcement matter undertaken by MRO; however, that director or member of an MRO organizational group must recuse himself or herself from any board or organizational group decisions, meetings, and actions related to that compliance monitoring and enforcement matter. Potential concerns about the participation of a MRO director or member of an MRO organizational group are brought to the attention of the President and CEO who will seek an appropriate resolution of the matter with the advice and counsel of the independent directors.

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties.** MRO has a RRSPM which has been approved by NERC and FERC. This RRSPM is based on the set of common attributes that provide for an open, balanced, fair, transparent and inclusive standard development process, and includes specific provisions relating to the process for the opportunity to comment and be heard. Additionally, MRO organizational group and board meetings are open to the public, and announcements to these meetings are widely disseminated in advance, providing entities an opportunity to provide input to MRO's processes.

v. **Provide for taking appropriate steps to gain recognition in Canada**. MRO operates under provincial Manitoba regulations which were adopted in 2012. MRO and NERC have a memorandum of understanding with Manitoba Hydro that was executed in 2018.

MRO and NERC have a memorandum of understanding with Saskatchewan Power Corporation governing MRO's work in Saskatchewan, Canada that was executed in 2015.

3. **MRO operates under a delegation agreement that promotes effective and efficient administration of BPS reliability.** On December 11, 2018,[18] the Office of Energy Market Regulation approved the requests of Wisconsin Public Service Corporation and Upper Michigan Energy Resources Corporation to transfer their registrations from MRO to ReliabilityFirst and the revision of MRO's RDA to reflect this transfer. Previously, on May 4, 2018,[19] the Commission approved the amended and restated MRO RDA to reflect the changed geographic footprint of MRO to be effective July 1, 2018. The 2018 RDA maintained the RDA provisions from the 2015 RDA (approved by the Commission on November 2, 2015,[20]) which incorporated benefits of NERC's and MRO's mutual experience and lessons learned while operating under the predecessor agreement. The RDA provides for efficient and effective execution of responsibilities that promote the reliability of the BPS. These responsibilities include: (i) development and proposal of Reliability Standards; (ii) enforcement of compliance with Reliability Standards; (iii) certification of BPS entities; (iv) registration of owners, operators, and users of the BPS; (v) reliability assessment and performance analysis; (vi) event analysis and reliability improvement; (vii) training and education; and (viii) situation awareness and infrastructure security.

   MRO has adopted high reliability organization principles in its approach to its delegated responsibilities, an approach that supports risk-based compliance monitoring and enforcement. These principles recognize risk, and emphasize self-monitoring with strong corrective action programs. The approach has fostered greater engagement with registered entities to solve technical problems and resulted in a corporate theme—clarity, assurance, and results. Clarity sets clear expectations for registered entities on the technical requirements of the standards. Assurance measures performance against these key requisites. Results can be seen in improved reliability. For example, MRO leverages the technical expertise of subject matter experts on stakeholder-led organizational groups to develop application guides for NERC standards that provide clear expectations of compliance. While these application guides are not authoritative, they provide much needed direction on compliance requirements, and many have been endorsed by the ERO Enterprise as Implementation Guidance. As a result, MRO has seen a measurable drop in the frequency and severity levels of violations in higher risk standards, beginning with the most violated Reliability Standard several years ago, PRC-005.

   Additionally, an MRO stakeholder-led organizational group developed an internal controls and procedures framework for use by registered entities to strengthen their internal compliance programs. These types of guidelines provide the necessary clarity to industry to assure that key reliability requirements are met.

   Registered entities, too, need to provide assurance to MRO staff that they understand the requirements and have established sustainable management practices to detect, correct, report, and prevent problems. Registered entities that have demonstrated their ability to identify their own noncompliances, accurately assess the risk, mitigate the noncompliances

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18 *Letter Order Approving Registration Request of WPSC and UMERC (2018).*

19 *North American Electric Reliability Corporation*, 163 FERC ¶ 61,094 (2018).

20 2015 RDA Order, *supra* n.9.

and put actions in place to prevent recurrence, as provided in the NERC guide for the ERO Enterprise Self-Logging Program, are eligible to participate in the Self-Logging Program in the MRO Region. Through the assessment period, MRO has 24 registered entities participating in the program.

C. ReliabilityFirst Corporation ("ReliabilityFirst")

ReliabilityFirst was formed from parts of the former East Central Area Reliability Council, Mid-America Interpool Network, and the Mid-Atlantic Area Council regional reliability councils on January 1, 2006. The organization was specifically designed to address changes required by the Energy Policy Act of 2005 and to support the ERO in a self-regulating model by which the industry participants establish their own standards and independent Regional Entities determine compliance to those standards. The organization was modified from top to bottom compared to the legacy reliability councils it replaced, and exists solely to serve as a FERC-approved Regional Entity performing only those functions delegated to it by NERC as the ERO. All ReliabilityFirst staff are independent of registered entities, the organization is governed by a hybrid board of directors, which includes both independent and balanced industry sector directors, and the organization is funded (through the ERO) by all load-serving entities in the footprint as opposed to members.

ReliabilityFirst continues to meet the relevant statutory and regulatory criteria for delegation as follows:

1. **ReliabilityFirst "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board."** ReliabilityFirst is governed by a combination independent and balanced stakeholder board, which consists of 14 directors: (i) three are independent directors; (ii) three are at-large directors elected by all the industry sectors voting together as a single class; and (iii) eight are elected by their industry sectors (suppliers elect two directors, transmission companies elect two directors, Regional Transmission Organizations elect one director, small LSEs elect one director, medium LSEs elect one director, and large LSEs elect one director).

2. **ReliabilityFirst met the requirements of § 215(c)(1)(2) of the Federal Power Act, because:**

   a. **ReliabilityFirst is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system.** Although ReliabilityFirst no longer develops Regional Reliability Standards in order to avoid duplication with the NERC continent-wide Reliability Standards, ReliabilityFirst has adopted a regional RRSDP, and has otherwise proved its ability to develop Regional Reliability Standards, as illustrated by its development of ReliabilityFirst Regional Reliability Standard BAL-502-RFC-02 - Planning Resource Adequacy Analysis, Assessment and Documentation, which was approved by the Commission on March 17, 2011. The purpose of the regional standard is to establish common criteria, based on "one day in ten" loss of load expectation principles, for the analysis, assessment, and documentation of resource adequacy for load in the ReliabilityFirst footprint. During the assessment period, ReliabilityFirst revised this Regional Standard (now titled BAL-502-RF-03) to add time horizons to its requirements, and to include a requirement for planning coordinators to identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis. FERC approved the revised Regional Standard on October 16, 2017.

      ReliabilityFirst has sufficient staff with the requisite expertise to conduct compliance audits, investigations, spot checks, and other compliance reviews, and to enforce Reliability Standards as demonstrated in part by its performing over 200 audits and 28 spot checks during the assessment period, and ensuring the mitigation of over 1300 alleged violations of those standards. These activities have resulted in tangible improvements to the reliability of the BPS. ReliabilityFirst develops a Compliance Oversight Plan for each entity, based on the key Risk Elements identified by NERC and ReliabilityFirst, and the unique risks posed by the entity. It then tailors compliance monitoring activities around these Compliance Oversight Plans, to provide a customized, risk-based approach. To enhance its risk-determination process in enforcement, ReliabilityFirst developed a "Risk-Harm" process which, among other things, provided for technical experts to answer a series of questions about the risk and harm posed by each violation using a common scale to ascertain a quantified risk assessment for each violation. Additionally, for serious violations of the NERC Reliability Standards, ReliabilityFirst works with registered entities to implement substantial reliability enhancements beyond baseline compliance, to improve reliability on their system and on the BPS.

   b. ReliabilityFirst has established rules that:

      i. **Assure its independence of the users and owners and operators of the BPS, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure.** As described earlier, ReliabilityFirst is governed by a combination independent and balanced stakeholder board. Pursuant to ReliabilityFirst's bylaws, no two industry sectors can control

any ReliabilityFirst decision and no single industry sector can veto any ReliabilityFirst decision. This hybrid board structure assures ReliabilityFirst's independence, while still assuring fair stakeholder representation and balanced decision-making. To further assure ReliabilityFirst's independence of the users, owners and operators of the BPS, ReliabilityFirst has the following protections in place:

- First, ReliabilityFirst adopted the NERC CMEP, Appendix 4C to the NERC ROP, which provides fair and impartial procedures for the monitoring and enforcement of Reliability Standards.

- Second, all ReliabilityFirst employees, contractors, and directors sign and must adhere to non-disclosure and confidentiality agreements and conflict of interest forms, and ReliabilityFirst employees, contractors, and directors are governed by the ReliabilityFirst *Conflict of Interest Policy*, the ReliabilityFirst *Code of Business Conduct and Ethics*, and § 1500 of the NERC ROP.

- Third, to ensure the independence of its staff and eliminate any potential conflicts of interest, ReliabilityFirst does not allow stakeholder participation in its compliance or enforcement activities (i.e., a registered entity staff member may not be on a ReliabilityFirst audit or compliance investigation team).

- Fourth, ReliabilityFirst does not allow its industry sector directors to participate in settlement discussions with ReliabilityFirst on behalf of their registered entity.

ii. **Allocate equitably reasonable dues, fees, and other charges among end users for all activities**. The funding for ReliabilityFirst's activities is equitably allocated among its end users and recovered through a formula based on NEL. Each year, ReliabilityFirst develops an annual business plan and budget, which describes the adequate resources needed for ReliabilityFirst to carry out its delegated functions. The annual business plan and budget and the assessments to the end users must be approved by the Commission. The annual business plan and budget process, the Commission's approval of the assessments, and periodic financial audits by the Commission all ensure that ReliabilityFirst's expenses and assessments to end users are reasonable.

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties.** ReliabilityFirst has adopted the NERC CMEP, Appendix 4C to the NERCROP, which provides fair and impartial procedures for the enforcement of Reliability Standards within ReliabilityFirst's geographic boundaries. Additionally, ReliabilityFirst maintains the ReliabilityFirst *Conflict of Interest Policy* and the ReliabilityFirst *Code of Business Conduct and Ethics* to ensure the integrity and independence of its compliance and enforcement staff. To

assess fair, impartial, and consistent penalties, ReliabilityFirst follows the *Sanction Guidelines*, as set out in Appendix 4B to the NERC ROP.

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties.** Although ReliabilityFirst no longer develops new regional Reliability Standards, ReliabilityFirst's RRSDP provides for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in the development of Reliability Standards.

The RRSDP includes public notice and a comment period for any proposed standard, due consideration of those public comments, and a ballot of interested stakeholders. Participation in the standards development process is open to all entities that are directly and materially affected by reliability in the ReliabilityFirst region, and there are no undue financial barriers to participation. The standards development process is balanced: it may not be dominated by any two interest categories, and no single interest category shall be able to defeat a matter.

ReliabilityFirst provides for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in its CMEP activities. A registered entity has the right to receive notice when it is placed on the NERC Compliance Registry, and it may appeal its registration to NERC and to the Commission.

The CMEP requires ReliabilityFirst to provide notice to a registered entity when it determines that the registered entity has violated a Reliability Standard, and the registered entity has an opportunity to respond. If a registered entity wishes to contest an alleged violation of a Reliability Standard or a penalty, it may request and receive a hearing, and may appeal the hearing decision to NERC. A registered entity also has the right to request a hearing to contest a twice-rejected mitigation plan or a remedial action directive.

At the conclusion of an enforcement matter, NERC publicly files a Notice of Penalty with the Commission, which promotes openness and the opportunity for public comment. The ERO balances the interest in openness with the concern for the security of critical infrastructure information, and as such, all sensitive critical infrastructure information is redacted from all public Notice of Penalty filings.

v. **Provide for taking appropriate steps to gain recognition in Canada and Mexico.** This criterion is not applicable to ReliabilityFirst, as its geographic boundaries do not include any portion of Canada or Mexico.

3. **ReliabilityFirst operates under a delegation agreement that promotes effective and efficient administration of BPS reliability**. On November 2, 2015,[21] the Commission approved the amended and restated NERC and ReliabilityFirst RDA which incorporated benefits of NERC's and ReliabilityFirst's mutual experience and lessons learned while operating under the predecessor agreement. The revised RDA provides for more efficient and effective execution of responsibilities that promote the reliability of the BPS. These responsibilities include: (i) development and proposal of Reliability Standards; (ii) enforcement of compliance with Reliability Standards; (iii) certification of BPS entities; (iv) registration of owners, operators, and users of the BPS; (v) reliability assessment and performance analysis; (vi) event analysis and reliability improvement; (vii) training and education; and (viii) situation awareness and infrastructure security.

   ReliabilityFirst only performs those activities delegated to it under the RDA. ReliabilityFirst has promoted effective and efficient administration of the BPS in its footprint during the assessment period through its successful implementation of the CMEP. For example, during the assessment period, ReliabilityFirst successfully processed and ensured the mitigation of over 1300 violations; completed over 200 audits; analyzed over 150 events; and conducted significant outreach efforts. These outreach efforts included a widely used assist visit program (targeted training based on the needs of the entity), bimonthly newsletters, and various risk-based training events and workshops throughout the year.

D. SERC Reliability Corporation ("SERC")

SERC was incorporated in April 2005, replacing the regional reliability council previously in existence since 1969. The new organization was redesigned to meet Federal Power Act § 215 and FERC criteria for delegating statutory authorities and responsibilities. SERC's scope includes only statutory functions delegated by NERC. The organization does not perform any registered entity functions and has no business affiliations with any registered entities. Under SERC's bylaws, SERC has a balanced stakeholder board with seven sectors. All SERC staff are independent of registered entities. The organization is funded through the ERO. Membership is free and open to all owners, operators, and users in the SERC region.

SERC continues to meet the relevant statutory and regulatory criteria for delegation as follows:

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[21] 2015 RDA Order, *supra* n. 9.

1. **SERC "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board."** SERC is governed by a balanced stakeholder board. Stakeholders are classified by the SERC Board Executive Committee in one of seven sectors (investor-owned utility sector, federal/state sector, cooperative sector, municipal sector, marketer sector, merchant electricity generator sector, and ISO-RTO sector). SERC's bylaws establish voting rules that ensure that no two sectors are able to approve a decision and that no one sector can veto a decision.

2. **SERC met the requirements of § 215(c)(1)(2) of the Federal Power Act, because:**

    a. **SERC is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system.**

    Standards: The SERC RRSDP defines the process for the development, revision, reaffirmation, and withdrawal of Regional Reliability Standards. The SERC RRSDP requires any proposed Regional Reliability Standard to be more stringent than a continent-wide Reliability Standard, whether the Regional Reliability Standard addresses matters that the continent-wide Reliability Standard does not or the Regional Reliability Standard is necessitated by a physical difference in the BPS within the SERC region. SERC Regional Reliability Standards are required to provide for as much uniformity as possible with continent-wide reliability standards. Proposed SERC Regional Reliability Standards are subject to approval by NERC and FERC prior to becoming mandatory and enforceable within the SERC region.

    SERC has one FERC-approved Regional Reliability Standard, PRC-006-SERC-02, which addresses automatic underfrequency load shedding requirements. SERC currently is not developing any additional Regional Reliability Standards because the continent-wide NERC Reliability Standards are presently adequate for the SERC region. SERC also participates in the NERC Standards Committee, hosts biannual meetings of the SERC Standards Committee, and hosts specific commenting sessions for NERC Standards Projects as NERC requests comments, all of which involve the discussion of proposed changes to NERC Reliability Standards.

    Compliance: SERC's authority to monitor reliability standards is based on the authority granted in its Delegation Agreement with NERC. SERC has the expertise on staff to conduct compliance audits, investigations, spot checks, and other compliance reviews for the Operating, Planning, and CIP Reliability Standards. SERC develops and posts an annual CMEP implementation plan that is complementary to the NERC CMEP, but also addresses reliability issues specific to the SERC region. SERC utilizes off-site and on-site audits, spot checks, and other compliance monitoring methods to assess registered entity compliance with NERC Reliability Standards. Compliance prepares detailed reports on each audit and makes recommendations to Enforcement about possible violations of NERC Reliability Standards.

Enforcement: Over the past five years, SERC has demonstrated its ability to enforce Reliability Standards by processing approximately 800 alleged violations originating from audits, spot checks, self-certifications, self-reports, and compliance investigations following the requirements of the CMEP and NERC ROP. Enforcement staff conducts a thorough assessment of all possible violations to determine whether there is a sufficient basis to allege a violation. If a sufficient basis exists, Enforcement staff determines the complete scope of the violation and the actual and potential risk to the reliability of the BPS. Enforcement staff reviews the registered entity's mitigating activities to ensure that the entity corrects the noncompliance and prevents recurrence. Enforcement staff also participates in settlement negotiations with the registered entity. SERC's processing of possible violations has improved because of increased resources and improved tools such as Compliance Exceptions, Find, Fix and Track, and the Spreadsheet Notice of Penalty filing mechanisms.

b. SERC has established rules that:

i. **Assure its independence of the users and owners and operators of the BPS, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure**. SERC's bylaws allow each SERC member company to appoint a director to SERC's board. The SERC Board Executive Committee is made up of 12 sector representatives from among the directors. All directors, alternate directors, and board committee representatives are required to comply with SERC's standards of conduct policy that prohibits participation in decisions that could pose a conflict of interest.

SERC's bylaws establish voting rules that ensure that no two sectors are able to approve a decision and that no one sector can veto a decision. These voting rules assure SERC's independence of the users, owners, and operators of the BPS. In addition, SERC has adopted the NERC CMEP, Appendix 4C to the NERC ROP, which provides fair and impartial procedures for the monitoring and enforcement of Reliability Standards. In addition, SERC employees and contractors sign non-disclosure and confidentiality agreements and conflict of interest forms.

ii. **Allocate equitably reasonable dues, fees, and other charges among end users for all activities**. SERC develops a budget annually that will accomplish all delegated duties. The budget is reviewed and approved by SERC's board before going to NERC and FERC. The budget is paid by all registered entities based on their proportionate share, based on the NEL. Pursuant to § 202 of the NERC ROP, NEL is the net generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities. Each entity

reports the energy generated on an annual basis for the previous year. After verification by SERC, this data is provided to NERC.

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties**. SERC has adopted without exception the NERC CMEP, Appendix 4C to the NERC ROP, and the associated *Sanction Guidelines,* ROP Appendix 4B, which provide fair and impartial procedures for the enforcement of Reliability Standards within the SERC region. SERC maintains a *Conflict of Interest Policy* to ensure the integrity and independence of its compliance and enforcement staff. To ensure consistency and remain fair, unbiased and balanced in assessing penalties, SERC follows the *Sanction Guideline*s of NERC and compares the proposed penalty with similarly situated violations that have been filed with and approved by FERC. All proposed penalties are reviewed and approved by SERC's Managing Counsel, the General Counsel, and the CEO.

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and other exercising its duties.** The SERC RRSDP requires SERC to provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in development reliability standards.

SERC provides for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in its CMEP activities. A registered entity has the right to receive notice when it is placed on the NCR, and may appeal its registration to NERC and to the Commission.

The CMEP requires SERC to provide notice to a registered entity when it determines that the Registered Entity has violated a Reliability Standard, and the registered entity has an opportunity to respond. If a registered entity wishes to contest an alleged violation of a Reliability Standard or a penalty, it may request and receive a hearing, and may appeal the hearing decision to NERC. A registered entity also has the right to request a hearing to contest a twice-rejected mitigation plan or a remedial action directive.

At the conclusion of an enforcement matter, NERC publicly files a NOP with the Commission, which promotes openness and the opportunity for public comment. The ERO balances the interest in openness with the concern for the security of critical infrastructure information, and as such, all sensitive critical infrastructure information is redacted from all public NOP filings.

v. **Provide for taking appropriate steps to gain recognition in Canada and Mexico**. The SERC region does not extend into any part of Canada or

Mexico. Thus SERC has no need to establish rules that provide for taking appropriate steps to gain recognition in Canada or Mexico.

3. SERC operates under a delegation agreement that promotes effective and efficient administration of BPS reliability. On May 4, 2018,[22] the Commission approved the amended and restated SERC RDA to reflect the changed geographic footprint of SERC to be effective July 1, 2018. The 2018 RDA maintained the RDA provisions from the 2015 RDA (approved by the Commission on November 2, 2015[23]) which incorporated benefits of NERC's and SERC's mutual experience and lessons learned while operating under the predecessor agreement. The SERC RDA provides for more efficient and effective execution of responsibilities that promote the reliability of the BPS. These responsibilities include: (i) development and proposal of Reliability Standards; (ii) enforcement of compliance with Reliability Standards; (iii) certification of BPS entities; (iv) registration of owners, operators, and users of the BPS; (v) reliability assessment and performance analysis; (vi) event analysis and reliability improvement; (vii) training and education; and (viii) situation awareness and infrastructure security. SERC only performs those activities delegated to it under the RDA. SERC also performs outreach, included a widely used assist visit program (targeted training based on the needs of the entity), monthly newsletters, and various risk-based training events and workshops throughout the year.

E. Texas Reliability Entity, Inc. ("Texas RE")

Texas RE is a non-profit Texas corporation that was formed to serve as the Regional Entity for the Electric Reliability Council of Texas, Inc. ("ERCOT") region, and to preserve and enhance reliability in the region. Texas RE also performs non-statutory activities as the Reliability Monitor for the ERCOT region pursuant to its January 1, 2016 agreement with the Public Utility Commission of Texas ("PUCT") and ERCOT, the Independent System Operator in the region. As Reliability Monitor, Texas RE monitors and reports to the PUCT regarding market participants' compliance with state electric reliability regulations and reliability-related ERCOT Protocols and Operating Guides. The ERCOT region is the geographic area located within the state of Texas that operates under the jurisdiction of the PUCT and is not synchronously interconnected with any other Interconnection. The ERCOT region includes approximately 90 percent of the state's electric load and 75 percent of the land area in Texas.

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22 *North American Electric Reliability Corporation*, 163 FERC ¶ 61,094 (2018).

23 2015 RDA Order, *supra* n.9.

Texas RE continues to meet the relevant statutory and regulatory criteria for delegation as follows:

1. **Texas RE "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board."** Texas RE is governed by a combination independent and balanced stakeholder board consisting of nine members: four independent directors; two industry-affiliated directors; the Texas RE CEO; and two ex-officio non-voting directors (the Public Utility Commission of Texas Chairman or delegate, and the Public Counsel from the Office of Public Utility Counsel). The independent directors are elected by Texas RE membership to serve staggered three-year terms. The two industry-affiliated directors may not be from the same market sector and may not concurrently serve on the ERCOT ISO board of directors.

2. **Texas RE met the requirements of § 215(c)(1)(2) of the Federal Power Act, because:**

    a. **Texas RE is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system.** Texas RE follows the requirements as defined by the NERC ROP, including the CMEP, and by its RDA with NERC, including Texas RE's current Standards Development Process ("SDP"). Texas RE has used these documents to develop regional standards and to audit and enforce compliance with Reliability Standards. Texas RE's Member Representatives Committee ("MRC") oversees development of Texas RE Regional Standards.

    Standards Development: Texas RE participates in the NERC Standards Committee and develops, comments, and votes on NERC Reliability Standards. Texas RE also facilitates the NERC Standards Review Forum ("NSRF") on a monthly basis. The NSRF, which reports to the Texas RE MRC, is a stakeholder forum in the Texas RE region that discusses current NERC Reliability Standards and upcoming enforceable standards. In 2018, the Texas RE Reliability Standards Department conducted a five-year review of Regional Reliability Standard IRO-006-TRE-1 and, based on stakeholder input, recommended its retirement. In accordance with the SDP, Texas RE followed the steps to retire the regional standard.

    Compliance: Between January 1, 2015, and December 31, 2018, Texas RE successfully completed more than 200 audits or spot checks of registered entities for compliance with Reliability Standards, including Critical Infrastructure Protection Reliability Standards. More than 400 potential instances of noncompliance were discovered by Texas RE staff. Texas RE conducted Inherent Risk Assessments on all registered entities in its region, and used a risk-based approach to determine the scope of each compliance monitoring engagement. Texas RE staff also investigated possible violations of the Reliability Standards arising from BPS disturbances, outages, self-reports, and complaints. Texas RE requires all risk assessment and compliance monitoring employees to, at a minimum, complete NERC training classes for auditors and meet all other

requirements of the Compliance Monitoring Competency Guide of the ERO Enterprise Compliance Monitoring and Enforcement Manual.

Enforcement: In addition to the auditing program, Texas RE has a separate Enforcement group with a dedicated staff. The Enforcement group processes noncompliance identified through audits, spot checks, self-certifications, complaints, and self-reports, including self-logging. The Enforcement group significantly improved case processing efficiencies and by 2017 processed more violations than in 2015 and 2016 combined. Texas RE is committed to handling violations in a clear and transparent manner, with emphasis on establishing mitigation and maintaining reliability.

b. Texas RE has established rules that:

i. **Assure its independence of the users and owners and operators of the BPS, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure.** The Texas RE bylaws and corporate policies assure the organization is independent of users, owners, and operators of the bulk power system, while assuring fair stakeholder representation in selection of its directors and balanced decision-making. The Texas RE bylaws provide that the organization has a combination independent and balanced stakeholder board consisting of nine members: four independent members, two industry-affiliated members, the Texas RE CEO, and two ex-officio, non-voting members representing the Public Utility Commission of Texas and the Office of Public Utility Counsel. The four independent directors are elected by Texas RE membership to serve staggered three-year terms. Texas RE membership is free, voluntary, and open to any entity that is a user, owner, or operator of the ERCOT region BPS or that qualifies for membership with Texas RE and complies with the Texas RE bylaws. In addition to the structure of the board, independent directors and members of their immediate families or households may not: (i) have current or recent status (within the past two years) as a director, officer or employee of an ERCOT region NERC registered entity; or (ii) have direct business relationships, other than as customers, with any NERC registered entity. The two industry-affiliated directors are selected by the Texas RE MRC to serve two-year terms. The Texas RE MRC is made up of stakeholder entities. The two industry-affiliated directors must come from different Texas RE membership sectors: (i) System Coordination and Planning, (ii) Transmission and Distribution, (iii) Cooperative Utility, (iv) Municipal Utility, (v) Generation, or (vi) Load-Serving and Marketing.

ii. **Allocate equitably reasonable dues, fees, and other charges among end users for all activities.** Texas RE's bylaws and its RDA with NERC provide that it will allocate equitably reasonable dues, fees, and other charges among end users for its statutory activities. Each year Texas RE produces a draft budget using templates provided by NERC and posts the

draft on its website for public comment. The budget includes the costs necessary to perform Texas RE's statutory functions under the RDA with NERC and any expected income. The budget is reviewed for reasonableness by the Texas RE MRC and approved by the Texas RE board of directors, NERC, and FERC. Pursuant to Exhibit E to its RDA, assessments to fund Texas RE delegated functions and related activities are allocated to all load-serving entities in the region on the basis of NEL. Penalty monies received by Texas RE are applied as a general offset to its budget requirements for the subsequent fiscal year.

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties.** Texas RE has adopted and implemented the CMEP in accordance with its RDA with NERC. Texas RE strives to be fair, unbiased, and balanced in its enforcement actions and imposition of penalties, and its internal procedures incorporate these concepts. After a possible violation is discovered, either through registered entity self-identification methods or Texas RE compliance monitoring activities, the violation is reviewed and verified by the Enforcement group. Penalties are calculated using the NERC *Sanction Guidelines* and are reviewed in relation to similar penalties assessed in this and other regions. In addition, all penalties are reviewed by the Texas RE Director of Enforcement and by the Chief Operating Officer prior to issuance.

Texas RE also has policies and procedures to ensure its employees act with independence, ethics, integrity, fairness, and openness. All Texas RE employees and contractors must annually sign an ethics agreement, which requires them to conduct Texas RE business and activities ethically, with integrity, and refrain from situations where they have any conflict of interest. A conflict of interest arises when: (i) a person is in a position to derive a personal or financial benefit based on his or her actions or status as a Texas RE representative; or (ii) the action of any Texas RE representative is in any way detrimental to the best interests of Texas RE. A "personal or financial benefit" includes any ownership, investment, or compensation interest by the employee or a member of the employee's household. An employee must immediately inform the Texas RE Legal Department if a conflict of interest or even the appearance of a conflict of interest might exist, to allow the Legal Department to evaluate the situation. After full disclosure by the employee, the Legal Department may agree to conditions that appropriately limit any potential influence from a conflict of interest.

Texas RE also follows the CMEP requirement to provide biographies of all potential audit team members to registered entities prior to a compliance engagement and provide opportunity for entities to object to use of any employee where a potential conflict of interest may exist. At the end of each compliance monitoring engagement, registered entities are also provided a questionnaire which allows them to directly report to NERC any concerns they have with fairness, openness, or objectivity with respect to how Texas

RE conducted the engagement. In addition, Texas RE has an ethics and compliance hotline to allow anyone to report (anonymously if desired) any noncompliance by a registered entity and any ethics complaints they have concerning Texas RE.

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties.** As part of its RDA, Texas RE follows its approved SDP, which provides reasonable notice and opportunity for public comment, due process, and balancing of interests during development of Regional Standards. The SDP requires that proposed regional standards must be drafted by a standards drafting team and be posted for a public comment period prior to any vote on the standard.

Texas RE also conducts its general operations in a manner that is transparent to the public. As required by its bylaws, it posts public notices of its board and committee meetings on its public website and posts meeting materials, including draft budgets, for public review prior to the meetings. The Texas RE public website includes training materials, useful compliance information, and the contact information for key Texas RE personnel.

Texas RE also provides due process to registered entities seeking to contest a violation, penalty, or sanction. Texas RE adheres to the NERC ROP and CMEP, which require Regional Entities to provide registered entities reasonable notice of possible violations, the ability to contest a violation or penalty or sanction, and the ability to appeal such matters.

v. **Provide for taking appropriate steps to gain recognition in Canada and Mexico.** This criterion is not applicable to Texas RE.

3. **Texas RE operates under a delegation agreement that promotes effective and efficient administration of BPS reliability.** Texas RE is a Regional Entity organized on an Interconnection-wide basis.[24] On November 2, 2015,[25] the Commission approved the amended and restated Texas RE RDA which incorporated benefits of NERC's and Texas RE's mutual experience and lessons learned while operating under the predecessor agreement. The revised RDA provides for more efficient and effective execution of responsibilities that promote the reliability of the BPS. These responsibilities include: (i) development and proposal of Reliability Standards; (ii) enforcement of compliance with Reliability Standards; (iii) certification of BPS entities; (iv) registration of owners, operators, and users of the BPS; (v) reliability assessment and performance analysis; (vi) event analysis and reliability improvement; (vii) training and education; and (viii) situation awareness and infrastructure security.

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[24] 18 C.F.R. § 39.8(e) ("The Electric Reliability Organization shall and the Commission will rebuttably presume that a proposal for delegation to a Regional Entity organized on an Interconnection-wide basis promotes effective and efficient administration of BPS reliability and should be approved.")

[25] 2015 RDA Order, *supra* n.9.

F. Western Electricity Coordinating Council ("WECC")

WECC is the successor to the Western Systems Coordinating Council ("WSCC"), which was formed in 1967. WECC, established in April 2002, continues to be responsible for promoting and coordinating electric system reliability among industry stakeholders as had been done by WSCC since its formation. WECC's regional area extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of 14 Western states. Membership in WECC is open to all entities with an interest in the operation of the BPS in the Western Interconnection. All meetings are open and anyone may participate in WECC's standards development process.

In 2013, the WECC board of directors approved the bifurcation of the company into a Regional Entity (WECC) and a Reliability Coordination Company (Peak Reliability). The bifurcation, which became effective in 2014, was the culmination of significant work and signaled a major landmark in the history of the organization. Under this new structure, the Reliability Coordinator and interchange authority functions in the Western Interconnection were undertaken by Peak Reliability, a separate and independent company from WECC. Peak Reliability provides core and other associated reliability coordination services within the Western Interconnection. In July 2018, Peak Reliability announced its intent to wind down operations by the end of 2019.

WECC continues to meet the relevant statutory and regulatory criteria for delegation as follows:

1. **WECC "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board."** Since bifurcation, WECC has been governed by an independent board of nine directors, who are precluded from having any affiliation with any WECC members or Registered Entities operating in the Western Interconnection.

2. WECC met the requirements of § 215(c)(1)(2) of the Federal Power Act, because:

a. **WECC is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system.** WECC's authority to enforce Reliability Standards is based on the authority granted in its RDA with NERC. FERC's approval of the RDA conferred authority to WECC to manage and enforce compliance with FERC-approved Reliability Standards. Additionally, WECC develops Regional Criteria and practices to improve the functioning and efficiency of the Western Interconnection. This combination provides a forum for addressing system-wide issues and an oversight role to promote reliable operation of the Western Interconnection.

WECC used its reliability standard development and enforcement abilities to address changes occurring in the Western Interconnection and to further reliable operations in the interconnection. WECC proposed revisions to Regional Standard BAL-002-WECC to change required contingency reserves. The change requires a potentially higher amount of reserves than would be required by the continent-wide standard and provides a calculation method which is much clearer and easier to implement and audit than what was found in the prior version. One two occasions, WECC proposed revisions to Regional Reliability Standard BAL-004-WECC: once to address the application of an Automatic Time Error Correction exemption, and another to specify a calculation methodology. WECC also made revisions to Regional Standard IRO-006-WECC, to address entities' operations related to unscheduled flow relief. WECC proposed changes to Regional Standard VAR-501-WECC addressing use and operation of power system stabilizers within the interconnection. Further, WECC made revisions to Regional Standard FAC-501-WECC to address aspects related to the implementation of transmission maintenance inspection plans. WECC has proposed the retirement of Regional Reliability Standards PRC-004-WECC (dealing with protection systems and remedial action scheme misoperations) and VAR-002-WECC (dealing with automatic voltage regulation), as development of continent-wide reliability standards made the regional standards redundant and/or providing no greater reliability benefits.

WECC demonstrated its ability to enforce reliability standards during the assessment period through continued development and improvement of its CMEP activities and annual implementation plans. WECC worked collaboratively with the other Regional Entities and NERC in coordinating monitoring and enforcement activities for Registered Entities operating in multiple regions.

b. WECC has established rules that:

i. **Assure its independence of the users and owners and operators of the BPS, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure.** WECC's bifurcation-related institution of an entirely independent board of directors was accompanied

by the creation of a Member Advisory Committee (MAC). While directors are directly elected by the WECC membership, member interests are represented and input is given through the members themselves, but also by the MAC, which provides information and recommendations directly to WECC's Board of Directors regarding WECC policies and proposed board decisions. In addition, WECC staff members, and representatives from WECC member entities, routinely participate in WECC, ERO and ERO Enterprise committees and work groups.

ii. **Allocate equitably reasonable dues, fees, and other charges among end users for all activities**. The allocation of dues, fees and other charges is governed by § 11.1 of the WECC bylaws, Funding of Reliability Activities. WECC funds all activities undertaken pursuant to § 215 of the Federal Power Act in accordance with the funding provisions and procedures of that law and related FERC regulations and orders. The WECC Board approves an annual business plan and budget for submission to NERC and to FERC for their approval. WECC funds reliability activities undertaken outside the United States pursuant to agreements with appropriate Canadian or Mexican authorities in accordance with the provisions of those agreements. WECC has allocated recovery of its reliability activities based upon the NEL of participants in the Western Interconnection. To the extent that WECC elects to engage in activities not eligible for funding pursuant to § 215 of the Federal Power Act, it does so through the use of service fees and charges paid by the persons or entities that voluntarily participate in such activities. Those separate funds wholly support WECC's non-§ 215 activities.

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties.** WECC's RDA with NERC is based on the NERC *pro forma* Delegation Agreement and has been reviewed and approved by FERC. In coordination with NERC, WECC develops annual CMEP Implementation Plans, which identify how WECC will monitor Registered Entities' compliance with Reliability Standards. Along with NERC and other ERO Regional Entities, WECC has developed monitoring processes which assess individual Registered Entity risks and their potential impact on the BES; WECC tailored its monitoring and enforcement actions accordingly. WECC uses the NERC *Sanction Guidelines* as a framework for assessing fair and reasonable penalties, and considers all facts associated with the registered entity and the alleged violation. Individuals responsible for assessing, recommending, or negotiating penalties are not otherwise involved in compliance monitoring or discovery of violations. In other words, WECC specifically segregates the duties associated with violation discovery or review and violation disposition and penalty assessment. Furthermore, WECC has a layered review approach to penalties, including non-monetary ones. WECC's director of enforcement reviews all cases and proposed sanctions and penalties with the assistance of attorneys from WECC's Legal Department.

WECC management reviews the processes and procedures bi-annually. WECC's director of enforcement and managers within WECC's Enforcement group are Certified Compliance and Ethics Professionals. Finally, WECC's Enforcement staff receives regular training on all aspects of their duties to ensure consistency of application.

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties.** WECC uses the FERC-approved WECC Reliability Standards Development Procedures to develop Regional Reliability Standards along with regional criteria and regional business practices. These procedures assure that standards, criteria or practices will be developed in a fair and open manner, with contribution and review by subject matter experts, and that all affected and interested parties will have the opportunity to comment and vote during their promulgation. Illustratively, proposed standards are drafted by a standards drafting team, publicly posted, and subject to a mandatory public comment period prior to any vote.

In regard to the exercise of its other duties, WECC posts on its website notices of, and agendas and materials for board and committee meetings. WECC also adheres to the NERC ROP and the CMEP processes, which provide due process protections to registered entities with respect to compliance obligations and enforcement of standards violations. Accordingly, registered entities are provided reasonable notice of possible violations, and the right to contest a violation, penalty or sanction, and to appeal the Regional Entity's decisions to the NERC Board of Trustees Compliance Committee, and the Commission.

v. **Provide for taking appropriate steps to gain recognition in Canada and Mexico**. WECC has negotiated various agreements with the applicable governmental authorities for British Columbia, Canada, Alberta, Canada, and Baja, Mexico, the three international areas included in the Western Interconnection.

<u>British Columbia (BC):</u>

Under an Administration Agreement between the British Columbia Utilities Commission ("BCUC") and WECC, WECC acts as the administrator for the BCUC in carrying out certain activities relating to the Mandatory Reliability Standards program in British Columbia. Working under this agreement, WECC recommends entity registrations, receives and reviews self-reports, self-certifications, and periodic data submittals; conducts audits; and provides reports relative to the nature, severity and remediation of possible violations. At the BCUC's request, WECC has set up a

separate webCDMS portal, an electronic system to collect compliance data, dedicated to BCUC and its entities.

Alberta:

WECC acts as the Compliance Monitor for the Alberta Market Surveillance Administrator ("Alberta MSA"), under a Services Agreement between the Alberta MSA and WECC, in carrying out certain activities related to Alberta Reliability Standards, specific to the Alberta Electric System Operator ("AESO"), in Alberta, Canada. WECC operates under the Services Agreement with the Alberta MSA in conjunction with a pre-existing membership and operating agreement with the AESO. Similar to BCUC, WECC uses a separate webCDMS portal for the Alberta MSA and AESO.

Mexico:

Under a membership and operating agreement between Comisión Federal de Electricidad ("CFE") and WECC, WECC acted as CFE's compliance monitor for certain activities in Baja California, Mexico, monitoring compliance with CFE's mandatory Reliability Standards. In the latter part of the assessment period, Mexico's electricity market and regulatory structures changed dramatically. Mexico is moving from a fully vertically integrated national electricity company to an open market, permitting both private and public entities to participate in the generation, transmission and distribution of electricity. WECC and NERC negotiated a memorandum of understanding with the new Mexican regulatory agency, Comisión Reguladora de Energía (CRE); and WECC negotiated revisions to or new member and operating agreements and service agreements with the CRE and other Mexican agencies (which now perform different roles and functions under the new Mexican regime). WECC continued to formulate and implement annual Implementation Plans, with CFE or CRE, to establish the scope for standards monitoring, descriptions of monitoring methods, and outreach and training activities WECC undertakes for Mexican agencies and Baja-California-area market participants. As in British Columbia and Alberta, WECC uses a separate webCDMS portal for use by Mexican government agencies and market entities.

WECC does not have enforcement authority for any of the international jurisdictions within the Western Interconnection. WECC provides registration recommendations, compliance monitoring, reviews of mitigation plans and completed mitigation plans, and assessment recommendations with respect to alleged violations.

3. **WECC operates under a delegation agreement that promotes effective and efficient administration of BPS reliability.** WECC is a Regional Entity organized on an Interconnection-wide basis.[26] On November 2, 2015,[27] the Commission approved the amended and restated WECC RDA which incorporated benefits of NERC's and WECC's mutual experience and lessons learned while operating under the predecessor agreement. The revised RDA provides for more efficient and effective execution of responsibilities that promote the reliability of the BPS. These responsibilities include: (i) development and proposal of Reliability Standards; (ii) enforcement of compliance with Reliability Standards; (iii) certification of BPS entities; (iv) registration of owners, operators, and users of the BPS; (v) reliability assessment and performance analysis; (vi) event analysis and reliability improvement; (vii) training and education; and (viii) situation awareness and infrastructure security.

   WECC worked to maintain and improve the reliability and efficient administration of the Western Interconnection through a variety of activities in fulfilment of these responsibilities. WECC took active steps to review WECC regional standards, their interplay with NREC promulgated and FERC approved continent-wide Reliability Standards, and operations within the Western Interconnection. During the assessment period, WECC continued to develop and retire Regional Reliability Standards as deemed appropriate to foster reliable operations in the interconnection. WECC also participated in the development, amendment and retirement of NERC Reliability Standards; and assisted Canadian and Mexican regulatory authorities to adopt identical or similar Reliability Standards as those regulators deemed appropriate for their jurisdictions.

   WECC likewise promoted effective and efficient administration of the BPS in the Western Interconnection during the assessment period through its implementation of NERC's CMEP approved by the Commission. WECC followed and implemented ERO-wide development and advancement of CMEP processes and activities through a risk-based approach; risks *vis a vis* individual Registered Entity risks and regional/Western Interconnection risks. WECC assists Canadian and Mexican authorities, with jurisdiction in the Western Interconnection, to adopt Reliability Standards, to monitor compliance with their adopted standards, to identify and register BPS entities, to conduct reliability assessments, performance analysis, and event analysis, and to train and educate (both regulators and BPS entities) with regards to compliance responsibilities, reliability improvement, situational awareness and infrastructure security.

   WECC undertook assessments of entities within its region to determine whether registration was required pursuant to Commission approved revisions to the definition of the Bulk Electric System (BES) and its exclusions and inclusions. This aided in administering the BPS in identifying entities which were no longer to be registered and through identification of facilities which did and which did not constitute BES facilities for which registered entities would have compliance responsibilities. WECC also took and maintains efforts to associate responsible registered entities with their Planning

[26] 18 C.F.R. § 39.8(e) ("The Electric Reliability Organization shall and the Commission will rebuttably presume that a proposal for delegation to a Regional Entity organized on an Interconnection-wide basis promotes effective and efficient administration of BPS reliability and should be approved.").

[27] 2015 RDA Order, *supra* n.9.

Authorities, Transmission Planners, etc. and to have those entities confirm their respective roles and relationships.

WECC undertook periodic Operational Practices Surveys to review and share best practices of surveyed-entities' operational procedures and practices. Beginning in 2016, WECC conducted Reliability Assurance Visits in partnership with NERC. During these visits, WECC discusses with entities their operational practices, to identify and share with Western Interconnection entities (and beyond) where there are areas of excellence or concerns. WECC produces a public report that provides high level findings and concerns discovered during the Reliability Assurance Visits and holds a workshop to review the general findings.

Further, WECC managed a comprehensive planning database, provided guidance on the analysis and modeling of the transmission system, and developed scenario studies of system performance to establish operating policies and limits, and regional transmission planning. WECC provided forums and means of exchange for regional planners, Transmission Planers, and others involved in the modeling and planning for the systems comprising the Western Interconnection and the interconnection as a whole; thus facilitating their work and WECC's own responsibilities for reliability assessments, performance analysis and reliability improvement. In addition, WECC performed annual assessments of 10-year loads and resources in the Western Interconnection and created a 10-year coordinated plan of system growth. WECC also provided information to NERC for its annual summer and winter assessments of the reliability of the BPS. WECC continued production of an annual *State of the Interconnection* report to provide WECC's members and stakeholders with an independent assessment of data collected annually in the Western Interconnection. WECC studied the impacts the Clean Power Plan could have on electricity generation and transmission in the Western Interconnection. The study provided information to owners and operators of BPS facilities, state and regional authorities and federal agencies concerning the impacts identified and would have enabled them to plan generation and transmission operations and facility expansion and retirements in recognition of the potential impacts. Further, WECC undertook and published an independent study of the relationships between natural gas supply and natural gas transmission and electricity generation and electricity transmission; how natural gas industry operations and capabilities affect electricity industry participants and electricity generation and transmission; and the impacts of possible decisions to be made affecting both the natural gas and electricity markets of the Western Interconnection.

IV. CONCLUSION

For the reasons stated above, each of the six Regional Entities (NPCC, MRO, ReliabilityFirst, SERC, Texas RE, and WECC) continues to meet the Regional Entity delegation criteria provided in § 215 of the Federal Power Act and part 39 of the Commission's regulations.

FEDERAL ENERGY REGULATORY COMMISSION
DOCKET NO. RR19-___

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

EXHIBIT C

TO

FIVE-YEAR ELECTRIC RELIABILITY ORGANIZATION PERFORMANCE ASSESSMENT REPORT

Stakeholder Comments in Response to April 2019 Posting of Draft Five-Year Performance Assessment

JULY 22, 2019

Comments of Large Consumers on NERC Draft Five-Year Electric Reliability Organization Performance Assessment Report
April 15, 2019

ELCON, on behalf of Large End-Use Consumers (Sector 8 of Member Representatives Committee), submits the following comments on NERC's draft "Five-Year Electric Reliability Organization Performance Assessment Report". Large Consumers place a particularly high value on electric reliability and appreciate NERC's diligence in evaluating the risks to Bulk Electric System (BES) security. Large Consumers also place a high value on procurement flexibility and are very sensitive to cost impacts. As such, Large Consumers seek to ensure that NERC actions have demonstrated reliability benefits that justify any added costs, rely on incentives instead of standards where appropriate, and preserve procurement flexibility throughout the supply chain.

Large Consumers concur that NERC continues to satisfy the statutory and regulatory criteria for ERO enterprise certification under 18 C.F.R. § 39.3(b). NERC has been successful in improving the effectiveness and efficiency of ERO Enterprise operations, strengthening operational alignment, and boosting information sharing and analysis.

The ERO Enterprise also effectively identifies and assesses emerging risks to the Bulk Power System (BPS). This function becomes increasingly important as the fuel mix evolves. NERC evaluations such as Special Reliability Assessments and Long Term Reliability Assessments may help inform grid operator procedures and state and regional procurement processes. Large Consumers emphasize that procurement processes are well situated to procure sufficient nameplate capacity, and that the performance of these resources under different contexts is more useful for the ERO Enterprise to examine moving forward.

Large Consumers agree with NERC that its ability to develop reliability standards comport with the achievement of an adequate level of reliability, as conventionally defined. However, what constitutes an adequate level of reliability varies greatly by consumer and specific end use of electricity. Homogenous standards do not reflect heterogeneous consumer preferences and often restrict supplier and consumer procurement flexibility. The imposition of standards treats reliability as exogenous, which restricts the ability of procurement policies to treat reliability as endogenous (e.g., demand response). Endogenous reliability would enable utilities and

wholesale market design to better differentiate services, such that consumers receive a level of service that they are willing to pay for.

Prescriptive standards can also undermine the cost-effectiveness of complying with system-wide reliability standards. For example, capacity market design is intended to achieve a system reliability level by incenting the most efficient and reliable behavior from market participants, including actions to firm fuel supplies. If NERC pursues prescriptive fuel assurance standards, it will undermine market policies, restrict procurement flexibility, and raise costs to consumers unnecessarily. Overall, greater scrutiny on the proper role of standards is important as the ERO Enterprise evolves.

NERC's pursuit of a risk-based approach is well founded. The shift away from "zero tolerance" policy is welcome but requires a definition of an acceptable level of risk, which NERC is yet to address. Large Consumers strongly emphasis that this definition incorporate consumer preferences and basic economic principles as part of the future direction of the ERO Enterprise.

Specifically, where standards are appropriate, they should ensure benefits outweigh costs and evaluate whether more cost-effective alternatives exist. In lieu of or as a compliment to mandatory standards, NERC has a vital role to play in promoting risk-informed decision making. This is especially the case where NERC-registered entities already have incentive to behave in a reliable manner but face an information deficit. Cybersecurity policy is a key case in point.

Cybersecurity Standards and Information Sharing

NERC's work on cybersecurity supply chain risks is a case where the appropriateness, nature, and stringency of standards come into question. NERC's report on cybersecurity supply chain risks recognizes the complex and evolving nature of supply chain risks and contains recommendations for further study and standards development work.

Large Consumers appreciate the report's recognition of differentiated treatment for Electronic Access Control or Monitoring Systems (EACMS) based on risk level: namely that electronic access controls present a higher risk than monitoring and logging systems. Large Consumers agree with supporting NERC Staff's recommendation that only EACS be included and not monitoring and logging systems. In addition, Large Consumers encourage NERC to work with industry to explore opportunities to streamline the verification process for EACMS, protect procurement flexibility, and promote information sharing. Industry does not support prescriptive standards, preferring flexibility in application and implementation.

Large Consumers appreciate the report's recognition that low-impact BES Cyber Systems pose a low risk to the reliability of the BES and support NERC's recommendation that low-impact BES Cyber Systems should not be included in the Supply Chain Standards. Large Consumers underscore the report's recognition that risk is mitigated as organizations with medium and high impact systems implement supply chain standards across their fleet that includes low-impact BES Cyber Systems. The report correctly notes that risk is further mitigated by supply chain vendors who implement supply chain standards across their systems, not knowing whether they will reside in low, medium or high impact systems.

The report recommends the low-impact BES Cyber System issue continue to be monitored. Any perceived deficiencies do not necessarily require modifications to mandatory standards. Doing so may be counterproductive – given the rapid pace that cyber threats and best practices evolve – or, at least, may impose excessive costs or restrictions on operations and procurement flexibility. Large Consumers strongly recommend that NERC account for costs and expected benefits in considering mandatory requirements for low impact systems and recognize that mandatory requirements are unnecessary where the incentives of vendors and low impact entities are aligned with BES security.

Where entities' incentives align with BES security, NERC should explore tools to motivate voluntary improvements by helping entities make better risk-informed decisions tailored to their unique circumstances. As such, additional information collection efforts should be done in mind with enhancing voluntary actions by entities with low-impact BES Cyber Systems.

NERC staff may want to tailor questions in any surveys, questionnaires, or data requests to not only evaluate current practices, but also gauge obstacles to adoption of best practices and cost considerations of changing practices. This would inform next steps on considering modifications to standards affecting low impact systems, such as better accounting of costs and expected benefits, as well as the efficacy of improved guidance and information sharing to improve voluntary practices in lieu of mandatory standards. For example, NERC could issue guidelines for on-site testing and other processes as an alternative to prescriptive management of supply and transport arrangements.

###

From:	Lawson, Barry R.
To:	Five Year Performance Assessment
Cc:	Lawson, Barry R.
Subject:	RE: Five-Year Electric Reliability Organization Performance Assessment Announcement
Date:	Monday, April 15, 2019 4:33:48 PM
Attachments:	image001.png image005.png image002.png

**** Please use caution when clicking links or opening attachments ****

NRECA and the Cooperative Sector supports NERC's draft 5-Year ERO Performance Assessment and views the filing as an accurate representation of ERO activities of the last 5 years.

Thanks,

Barry

Barry R. Lawson
Senior Director, Regulatory Affairs
Government Relations Dept.
National Rural Electric Cooperative Association (NRECA)
4301 Wilson Blvd., Mail Code GR11-253
Arlington, VA 22203
PH 703.907.5781
FX 703.907.5517
CELL 703.966.3123
barry.lawson@nreca.coop

From: Marilani Alt <marilani.alt@nerc.net>
Sent: Wednesday, April 3, 2019 4:13 PM
To: Marilani Alt <marilani.alt@nerc.net>
Subject: Five-Year Electric Reliability Organization Performance Assessment Announcement

** Please use caution when clicking links or opening attachments **

Five-Year Electric Reliability Organization Performance Assessment Announcement

Notice of Draft Posting and Request for Comments

April 1, 2019

Comments Due: April 15, 2019

Comment Period for Draft Five-Year ERO Performance Assessment Report

The North American Electric Reliability Corporation ("NERC"), as the Electric Reliability Organization ("ERO") pursuant to Section 215 of the Federal Power Act, is required to submit an assessment of how it meets the statutory and regulatory criteria for ERO certification to the Federal Energy Regulatory Commission ("FERC").

NERC hereby posts its draft Five-Year ERO Performance Assessment Report for industry review and

respectfully requests comments on the posted documents.

Materials Included in this Request for Comments

- Draft Five-Year ERO Performance Assessment Report

Submission of Comments

Comments are due April 15, 2019, and must be submitted electronically to 5YPA@nerc.net. NERC intends to present a revised draft of the proposed Five-Year ERO Performance Assessment Report to the NERC Board of Trustees at its May 8, 2019 meeting. Although the comment period does not close until April 15, 2019, commenters are respectfully requested to submit their comments sooner, if possible, in order to provide additional time for NERC staff and the Regional Entities to consider them.

Please note that all original comments will be included as an exhibit in the Five-Year ERO Performance Assessment Report filed with FERC on or before July 22, 2019.

For further information, please contact Nina Johnston at 5YPA@nerc.net (via email) or at (202) 644-8049.

_____
Marilani Alt
Senior Legal Assistant, Legal & Regulatory
North American Electric Reliability Corporation
1325 G Street NW, Suite 600
Washington, DC 20005
202-400-3021 office | 202-420-1573 cell
Email: marilani.alt@nerc.net
Twitter @NERC_Official | LinkedIn
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Southwest Power Pool, Inc. Comments on

NERC's Five-Year Electric Reliability Organization Performance Assessment
April 15, 2019

Summary

Southwest Power Pool, Inc. (SPP) appreciate the opportunity to comment on the North American Electric Reliability Corporation (NERC)'s Five-Year Performance Assessment (Performance Assessment). Many programs and initiatives detailed in the Performance Assessment have improved the reliability and security of the Bulk Power System (BPS) over the past five years and SPP supports the inclusion of these in the Assessment. SPP asks NERC to consider additional information not contained in the Performance Assessment that will further illustrate the changes to the standards process, and its impact on the successful and expeditious completion of numerous standards projects during the five-year period. Furthermore, SPP reinforces to the Federal Energy Regulatory Commission (Commission) of the need for a technical stakeholder body and an open and transparent process even for projects that have been in development for longer periods. Finally, SPP seeks clarifications in the Performance Assessment's Section IV-Evaluating Regional Entity Performance that will better illustrate the impacts from the SPP Regional Entity.

Developing Reliability Standards and Ensuring Adequate Level of Reliability

SPP supports the efforts of the Standard Efficiency Review (SER) to remove or retire unnecessary reliability standards. Even though the SER process will reduce the number of requirements subject to compliance, the Performance Assessment should mention that the SER process does not degrade the level of BPS reliability. Efficiency gains in Registered Entity staff and resources due to retirement of unnecessary reliability standards will allow improved focus on core reliability needs and place more resources towards ensuring reliability rather than ensuring compliance. The Performance Assessment could also be improved with added explanation about the benefits of NERC reliability guidelines. SPP supports NERC's efforts to create reliability guidelines, particularly around newly identified risks that need attention quickly, such as the inverter-based resources guideline issued in 2018. It should be reported how reliability guidelines not only can expedite solutions to new risks but also how reliability guidelines allow for more flexibility and learning by the industry to innovate solutions to these new risks.

The new programs, tools and changes to the standards committee and standards development process is a commendable achievement in the past five years that has provided substantial results. NERC has achieved success due to its collaboration with industry and SPP encourages NERC to continue to provide open and transparent processes and conduct its operations in an efficient and effective manner. Transparency of processes is especially important for projects that have been open for extended amounts of time. Open and consistent communications regarding the status of delayed or projects on hold will maintain accountability and result in efficient and effective resolution of these projects. The Performance Assessment should remind the Commission that the standards development process is ANSI-accredited, which is the cornerstone of success to achieve consensus on complicated technical requirements and an effective process used to design the requirements that have ensured an adequate level of reliability for the BPS. The process has not only been successfully used to create new requirements, but also has proven effective to revise and improve existing ones as well. NERC also has

confidence that utilizing the same process to reduce the number of requirements will continue to assure that adequate level of reliability are met.

Electric Information Sharing and Analysis Center (E-ISAC)

SPP supports investment in E-ISAC and the Cyber security Risk Information Sharing Program (CRISP), and it is worth mentioning in the Performance Assessment that these programs are new and have been limited in participation due to its cost. The effectiveness of the E-ISAC and CRISP can be improved if existing restrictions that limit access to the information by BPS experts are lifted. Additional access to the information will allow these experts to focus alerts that are more actionable for the BPS.

Regional Entity Performance Data Clarification

Southwest Power Pool Regional Entity (SPP RE) performed Delegated Functions for the majority of the five-year assessment period (2014 – June 2018). It is not clear if the data tables, charts, and statistics throughout the Performance Assessment include or exclude the SPP RE's information. Footnote 44 is the only mention of the SPP RE and is specifically related to the exclusion of GADs and TADs data due to the termination of its RDA with NERC. The SPP RE is included in the Cause Coding charts (Pages 64-65). The Performance Assessment should clearly identify when SPP RE's data is included and when excluded – either globally or in each section. For example, Figure 5 on Page 34 of the report shows that MRO completed 172 IRAs for 198 Registered Entities in 2018. There is no indication in this section as to whether SPP RE's data in included or not. Figure B.3 in the 2017 CMEP Annual Report[1] shows that MRO's completion total was 103 for 113 Registered Entities. 108 Registered Entities were transferred from SPP RE to MRO mid-2018 and the increased total can be seen in the 2018 chart. The 2017 CMEP report also shows that SPP RE completed 109 IRAs for 116 Registered Entities. Since MRO's total number of Registered Entities increased from 113 to 198 from 2017 to 2018, it is unclear if the 172 IRA completion total includes or excludes IRAs completed by SPP RE. SPP would request the Performance Assessment clarify the SPP RE's role in these matters.

Conclusion

SPP appreciates the opportunity to provide comments on NERC's Performance Assessment and urges NERC to consider incorporating the recommendations to the Performance Assessment discussed above. SPP looks forward to working with NERC as it continues to improve the reliability and the security of the BPS.

[1] 2017 Compliance Monitoring and Enforcement Program Annual Report, February 7, 2018, Page 38.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)**	**Docket No. RM14-7-000**
	)	

NOTICE OF WITHDRAWAL OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR PROPOSED RELIABILITY STANDARD MOD-001-2

Pursuant to Rule 216[1] of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission"), the North American Electric Reliability Corporation ("NERC") hereby submits this notice of withdrawal for its petition for approval of proposed Reliability Standard MOD-001-2.

I. Background

On February 10, 2014, NERC submitted a petition for approval of proposed Reliability Standard MOD-001-1 in the above-captioned docket.[2] In NERC's petition, NERC also sought the retirement of Reliability Standards MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a, and MOD-030-2 ("MOD A" Standards). On June 19, 2014, the Commission issued a Notice of Proposed Rulemaking ("NOPR") proposing to approve MOD-001-2 and the retirement of the MOD A Standards.[3]

---

1 18 C.F.R. § 385.216 (2018).

2 *Petition of NERC for Approval of Proposed Reliability Standard MOD-001-2 and Retirement of Reliability Standards MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a, and MOD-030-2,* Docket No. RM14-7-000.

3 *Modeling, Data, and Analysis Reliability Standards* (2014), 147 FERC ¶ 61,208.

II. Notices and Communications

Notices and communications with respect to this filing may be addressed to the following:

Shamai Elstein
Assistant General Counsel, Legal and Regulatory
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
shamai.elstein@nerc.net

Howard Gugel
Senior Director of Engineering and Standards
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595 – facsimile
howard.gugel@nerc.net

III. Support for Withdrawal

Since the issuance of the NOPR, NERC has completed a comprehensive review of its Reliability Standards under its Standards Efficiency Review initiative. As a result of work under this initiative, and as discussed more fully in NERC's petition filed concurrently with this notice,[4] NERC has determined that it remains appropriate to retire the currently effective versions of the MOD A Reliability Standards, but without proposed Reliability Standard MOD-001-2 serving as a replacement standard. NERC has determined that the Requirements of proposed Reliability Standard MOD-001-2 are administrative in nature or relate expressly to commercial or business practices and would not advance reliability as originally contemplated.

Following approval by the NERC ballot body, the NERC Board of Trustees approved the retirement of the currently effective MOD A Reliability Standards and the withdrawal of proposed Reliability Standard MOD-001-2 on May 9, 2019. Additional information on the standards development process for these actions is available as **Exhibit F** to NERC's June 7, 2019 petition.

[4] *See Petition of the North American Electric Reliability Corporation for Approval of Revised and Retired Reliability Standards under the NERC Standards Efficiency Review*, filed June 7, 2019 (docket pending). Further information about the NERC Standards Efficiency Review initiative is available here: https://www.nerc.com/pa/Stand/Pages/Standards-Efficiency-Review.aspx.

IV. Conclusion

NERC requests that the Commission permit withdrawal of NERC's petition, either by order or expiration of the 15 day period in Rule 216.

Respectfully submitted,

/s/ Shamai Elstein

Shamai Elstein
Assistant General Counsel, Legal and Regulatory
Lauren A. Perotti
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
shamai.elstein@nerc.net
lauren.perotti@nerc.net

Counsel for the North American Electric Reliability Corporation

June 7, 2019

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of this submittal upon all parties listed on the official service lists compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 7th day of June, 2019.

/s/ Shamai Elstein

Shamai Elstein
Counsel for North American Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

May 28, 2019

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: NERC Cyber Security Supply Chain Risks: Staff Report and Recommended Actions
Docket No. RM17-13-000

Dear Secretary Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits the report titled, *Cyber Security Supply Chain Risks: Staff Report and Recommended Actions*. NERC submits this report to the Federal Energy Regulatory Commission (the "Commission") in accordance with the Commission's directive in paragraph 31 of Order No. 850.[1]

In Order No. 850, the Commission approved three Reliability Standards to help mitigate cyber security risks associated with the supply chain for high and medium impact BES Cyber Systems: Reliability Standards CIP-005-6, CIP-010-3, and CIP-013-1 (collectively, the "Supply Chain Standards").[2] In approving the Supply Chain Standards, the Commission issued two directives to NERC:

- First, the Commission directed NERC to modify the Supply Chain Standards to include Electronic Access Control and Monitoring System ("EACMS") functions within the scope of the standards.[3]

- Second, the Commission accepted NERC's commitment to study certain categories of assets not currently subject to the Supply Chain Standards in the NERC Board of Trustees-directed cyber security supply chain risk report and directed NERC to file the final report with the Commission upon its completion.[4]

---

1 *Supply Chain Risk Management Reliability Standards*, Order No. 850, 165 FERC ¶ 61,020 (2018).

2 Order No. 850 at P 28.

3 *Id.* at PP 30, 51.

4 *Id.* at P 31. As discussed in the enclosed report, when the NERC Board of Trustees adopted the Supply Chain Standards in August 2017, it also directed NERC to undertake further action on supply chain issues. Among other things, the NERC Board directed NERC to study the nature and complexity of cyber security supply chain risks, including those associated with low impact assets not currently subject to the Supply Chain Standards, and develop recommendations for follow-up actions that will best address identified risks.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

In the enclosed report, NERC Staff evaluates cyber security supply chain risks associated with certain categories of assets not currently subject to the Supply Chain Standards and recommends actions to address those risks. The recommendations are summarized below:

- EACMS: revise the Supply Chain Standards to address EACMSs that provide electronic access control (excluding monitoring and logging) to high and medium impact BES Cyber Systems.

- Physical Access Control Systems (PACS): revise the Supply Chain Standards to address PACSs that provide physical access control (excluding alarming and logging) to high and medium impact BES Cyber Systems.

- Low impact BES Cyber Systems: conduct further study to determine whether new information supports modifying the standards to include low impact BES Cyber Systems with External Routable Connectivity as follows: first, by issuing a Request for Data or Information pursuant to Section 1600 of the NERC Rules of Procedure;[5] and second, by continued monitoring of the application of the criteria in CIP Reliability Standards that differentiate medium impact BES Cyber Systems from low impact through the use of industry surveys and questionnaires following the implementation of the Supply Chain Standards.

- Protected Cyber Assets: work to develop a guideline to assist entities with evaluating their PCAs on a case-by-case basis to determine what, if any, additional supply chain protections are needed.

Since the NERC Board of Trustees accepted the report on May 9, 2019, NERC has taken prompt action to implement the recommended next steps. NERC, with the assistance of the Critical Infrastructure Protection Committee Supply Chain Working Group, is drafting a request for data or information under Section 1600 of the NERC Rules of Procedure to facilitate further study of the supply chain risks associated with low impact BES Cyber Systems. Additionally, NERC will initiate its standard development process in the coming months to consider the Commission's Order No. 850 EACMS directive and the standard modification recommendations in the report.

[5] NERC's Rules of Procedure are available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

NERC respectfully requests that the Commission accept the attached report submitted in accordance with the Commission's directive in Order No. 850.

Respectfully submitted,

/s/ Shamai Elstein
Senior Counsel
Lauren A. Perotti
Senior Counsel
North American Electric Reliability Corporation
1325 G St., NW, Suite 600
Washington, DC 20005
202-400-3000
shamai.elstein@nerc.net
lauren.perotti@nerc.net

Counsel to the North American Electric Reliability Corporation

Enclosure:

Cyber Security Supply Chain Risks: Staff Report and Recommended Actions (May 2019)

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 May, 2019.

/s/ Shamai Elstein

Shamai Elstein

Counsel for North American Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Cyber Security Supply Chain Risks

Staff Report and Recommended Actions

May 17, 2019

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3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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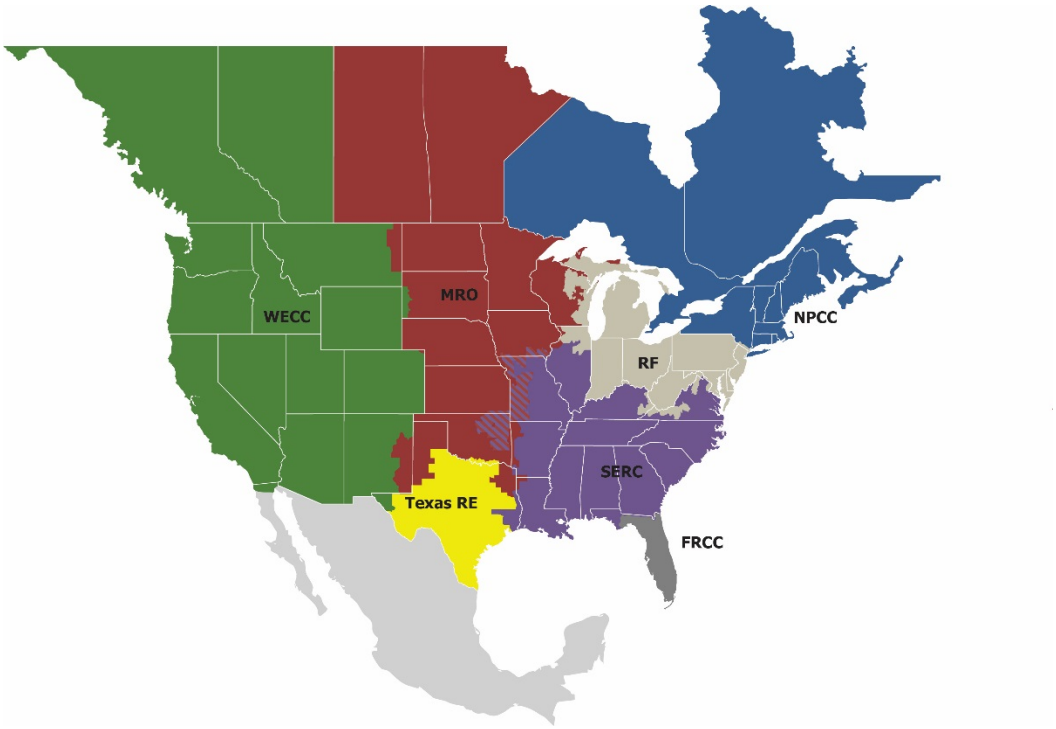
Acknowledgements

Apart from the efforts of NERC staff, the success of any report depends largely on the guidance and input of many others. NERC wishes to take this opportunity to express a special thanks to Dr. Joseph Baugh of the Western Electricity Coordinating Council and Ray Sefchik of Reliability First for their exceptional contributions in helping to improve the content of this report. NERC also wishes to take this opportunity to express a special thanks to the Critical Infrastructure Protection Committee Supply Chain Working Group for their valuable contribution to this report. The authors also acknowledge and appreciate the significant contributions from individuals, working groups, subject matter experts, and organizations whose thoughtful and constructive comments improved the overall quality, thoroughness, and usefulness of this report.

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

The supply chains for information and communications technology and industrial control systems may provide various opportunities for adversaries to initiate cyber attacks, thereby presenting risks to Bulk Electric System (BES)[1] security. NERC is committed to using its many reliability tools to support industry's efforts to mitigate supply chain risks.

In 2017, NERC developed new and revised critical infrastructure protection (CIP) Reliability Standards to help mitigate cyber security risks associated with the supply chain for high and medium impact BES Cyber Systems. These standards, collectively referred to as Supply Chain Standards, consist of new Reliability Standard CIP-013-1 and revised Reliability Standards CIP-010-3 and CIP-005-6. Consistent with the risk-based framework of the NERC CIP Reliability Standards, the Supply Chain Standards will be applicable to the highest-risk systems that have the greatest impact to the grid. The Supply Chain Standards will require entities that possess high and medium impact BES Cyber Systems to develop processes to ensure responsible entities manage supply chain risks to those systems through the procurement process, thereby reducing the risk that supply chain compromise will negatively impact the BPS.

When adopting the Supply Chain Standards in August 2017, the NERC Board of Trustees (Board) directed NERC to undertake further action on supply chain issues. Among other things, the NERC Board directed NERC to study the nature and complexity of cyber security supply chain risks, including those associated with low impact assets not currently subject to the Supply Chain Standards and develop recommendations for follow-up actions that will best address identified risks.

In this report, NERC documents the results of the evaluation of supply chain risks associated with certain categories of assets not currently subject to the Supply Chain Standards and recommends actions to address those risks.

Upon evaluation of the potential supply chain risks presented by Electronic Access Control or Monitoring Systems (EACMSs), and in response to the directive of FERC in Order No. 850 to include such systems within the scope of the Supply Chain Standards,[2] NERC staff recommends revising the Supply Chain Standards to address EACMSs that provide electronic access control (excluding monitoring and logging) to high and medium impact BES Cyber Systems.

Additionally, based on the supply chain risks presented by such assets, NERC staff recommends revising the Supply Chain Standards to address Physical Access Control Systems (PACSs) that provide physical access control (excluding alarming and logging) to high- and medium-impact BES Cyber Systems.

At this time and based on the available information, NERC staff does not recommend modification of the Supply Chain Standards to include all low impact BES Cyber Systems. NERC staff recommends further study to determine whether new information supports modifying the standards to include low impact BES Cyber Systems with External Routable Connectivity as follows: first, by issuing a Request for Data or Information pursuant to Section 1600 of the NERC Rules of Procedure; and second, by continued monitoring of the application of the criteria in CIP Reliability Standards that differentiate medium impact BES Cyber Systems from low impact through the use of industry surveys and questionnaires following the implementation of the Supply Chain Standards. To address the potential risks associated with the supply chain for such systems prior to completion of this study, NERC staff will work with the Critical Infrastructure Protection Committee (CIPC) Supply Chain Working Group to develop a guideline to assist entities in voluntarily applying supply chain risk management plans to low impact BES Cyber Systems.

[1] Unless otherwise indicated, capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

[2] Order No. 850, *Supply Chain Risk Management Reliability Standards*, 165 FERC ¶ 61,020, at P 30 (2018) ("Order No. 850").

Due to varying levels of risk, NERC staff will work with the CIPC Supply Chain Working Group to develop a guideline to assist entities with evaluating their Protected Cyber Assets (PCAs) on a case-by-case basis to determine what, if any, additional supply chain protections are needed.

NERC staff recommends that entities refer to industry practices and guidelines, such as those developed by the North American Transmission Forum, the American Public Power Association and National Rural Electric Cooperative Association, and the North American Generator Forum, when developing their CIP-013-1 process(es) for the procurement of BES Cyber Systems.

Because supply chain risks are complex and constantly evolving, NERC staff also recommends conducting additional data collection on BES supply chain risk management through the use of industry surveys and questionnaires. Such evaluation may result in additional recommendations for future actions. To encourage full and frank industry participation, NERC Staff recommends that these surveys be completed independently of any mandatory compliance monitoring or enforcement process.

Next Steps on Recommendations

NERC will work through its existing processes with stakeholders to review NERC staff's recommendations and determine appropriate follow up actions.

Introduction

Background

In recent years, the Federal Energy Regulatory Commission (FERC or the Commission), NERC, and the industry have identified risks from the supply chain as a potential threat to BES reliability. Supply chains for information and communications technology and industrial control systems are long and multidimensional, involving numerous parties in a multitude of countries across the globe. In procuring products and services for their operations, BPS owners and operators typically rely on vendors and contractors that may use multiple third-party suppliers for components used in their products or technologies. Malicious actors may target one or more vendors in the supply chain to create or exploit vulnerabilities that could then be used to initiate cyber attacks on BES Cyber Systems and equipment.

On July 21, 2016, FERC issued Order No. 829,[3] directing NERC to develop a new or modified Reliability Standard that addresses supply chain risk management for industrial control system hardware, software, and computing and networking services associated with BES operations, as follows:

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

Following the issuance of Order No. 829, NERC staff initiated Reliability Standards Project 2016-03 Cyber Security Supply Chain Risk Management to address supply chain risk management in the CIP Reliability Standards. The project resulted in the development of the Supply Chain Standards that consist of new Reliability Standard CIP-013-1 and modifications to Reliability Standards CIP-005-6 and CIP-010-3.

The Supply Chain Standards support reliability by requiring responsible entities to implement plans and processes to mitigate supply chain cyber security risks to high and medium impact BES Cyber Systems. Consistent with Order No. 829, the proposed Reliability Standards focus on the following four security objectives: software integrity and authenticity, vendor remote access protections, information system planning, and vendor risk management and procurement controls.

Reliability Standard CIP-013-1 requires responsible entities to develop and implement plans to address supply chain cyber security risks during the planning and procurement of high and medium impact BES Cyber Systems. Modifications in CIP-005-6 and CIP-010-3 bolster the protections in the currently-effective CIP Reliability Standards by addressing specific risks related to vendor remote access and software integrity and authenticity, respectively, in the operational phase of the system life cycle.

The Board adopted the Supply Chain Standards at its August 10, 2017, meeting. FERC approved the Supply Chain Standards with directives for additional modifications to address EACMSs in Order No. 850, issued October 18, 2018.[5]

[3] Order No. 829, *Revised Critical Infrastructure Protection Reliability Standards,* 156 FERC ¶ 61,050 (2016).
[4] *Id.* at P 2 (internal citation omitted); *see also id*. at PP 44-45.
[5] Order No. 850, *supra* note 1.

August 2017 Board Resolutions

In adopting the Supply Chain Standards, the Board concurrently adopted additional resolutions related to implementation and risk evaluation.[6] The resolutions outline six actions for NERC management and stakeholders to take in assisting with the implementation and evaluation of the Supply Chain Standards as well as other actions to address potential supply chain risks for assets not currently subject to the standards.

The Board's August 2017 resolutions include the following:

- **Support Effective and Efficient Implementation of the Supply Chain Standards:** The Board requested that NERC promptly commence preparations for the implementation of the Supply Chain Standards by using similar methods during the transition to version 5 of the CIP Reliability Standards and report regularly to the Board on those activities.
- **Cyber Security Supply Chain Risk Study:** The Board requested that NERC, in collaboration with others, study the nature and complexity of cyber security supply chain risks, including those associated with low impact assets not currently subject to the Supply Chain Standards, and develop recommendations for follow-up actions that will best address identified risks. The Board requested that NERC submit an interim report within 12 months and a final report within 18 months. NERC presented the interim report to the Board in August 2018.
- **Communicate Supply Chain Risks to Industry:** The Board requested that NERC communicate supply chain risk developments and risks to industry in connection with the Cyber Security Supply Chain Risk Study (i.e. this report).
- **Forum White Papers:** The Board requested that the North American Transmission Forum (NATF) and the North American Generation Forum (NAGF) (collectively, the "Forums") develop (and distribute as permissible) white papers to address best and leading practices in supply chain management as described in the resolution.
- **Association White Papers:** The Board requested that the American Public Power Association (APPA) and the National Rural Electric Cooperative Association (NRECA) (collectively, the "Associations") develop (and distribute, as permissible) white papers to address best and leading practices in supply chain management, as described in the resolution, focusing on smaller entities that are not members of the Forums, for the membership of the Associations.
- **Evaluate Supply Chain Standard Effectiveness:** The Board requested that NERC, in collaboration with technical committees and other experts, develop a plan to evaluate the effectiveness of the Supply Chain Standards as described in the resolution and report to the Board.

The activities undertaken by NERC, the Forums, and the Associations to address the Board's supply chain resolutions are designed to establish a collective understanding of the supply chain risk to the BES and activities to mitigate those risks.

This report addresses the Board's second resolution, which is to prepare a study of cyber security supply chain risks. Building upon the interim report presented to the Board in August 2018 (discussed below), this report addresses the risks associated with low impact BES Cyber Systems, EACMSs, PCAs, and PACSs and the actions that should be taken to address those risks. This report also makes reference to certain white papers and guidance documents prepared by the Forums and Associations in response to the Board's fourth and fifth directives.

[6] The Additional Resolutions for Agenda Item 9.a: Cyber Security – Supply Chain Risk Management – CIP-005-6, CIP-010-3, and CIP-013-1, NERC Board of Trustees Meeting, August 10, 2017, is available at the following: http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Proposed%20Resolutions%20re%20Supply%20Chain%20Follow-up%20v2.pdf.

All reports are posted on NERC's website under the Supply Chain Risk Mitigation Program Initiative[7] page. In Appendix A to this report, NERC summarizes the activities taken to address the other Board resolutions.

EPRI Interim Report (August 2018)

NERC engaged the Electric Power Research Institute (EPRI) to provide an independent assessment of industry supply chain risks to facilitate NERC's supply chain risk study. NERC presented EPRI's report, titled *EPRI Supply Chain Risk Assessment Report*,[8] to the Board in August 2018. In this report, EPRI contributed the following actions:

- Performed an assessment of product/manufacturer types used on the BES for Supervisory Control and Data Acquisition (SCADA), network and telecommunications, and commercial off the shelf operating systems
- Provided an analysis of emerging best practices and standards used in other industries to mitigate supply chain risks, concentrating on practices currently not considered in the scope of the existing CIP Reliability Standards
- Provided a study of the applicability of the CIP Reliability Standards to supply chain risks
- Provided a list of recommendations to reduce residual supply chain risks and facilitate the collection of additional information for future evaluation, so that, prior to any changes in policy, data can be obtained, assessed, and discussed in a transparent manner

Forum and Association White Papers

In response to the Board's fourth resolution, the NATF and NAGF each prepared White Papers that provide considerations for their member entities on implementing robust cyber security risk management plans and programs.

The NATF White Paper, titled *Cyber Security Supply Chain Risk Management Guidance*,[9] recommends several best and leading practices for members in establishing and implementing their supply chain risk management programs. These practices include considerations for procurement, specification, vendor requirements, and managing existing equipment activities. NATF's White Paper identifies three hallmarks of an effective program, including foundational practices that coordinate supply chain and cyber security risk management efforts; organization-wide communication where supply chain risk management is supported throughout the business and implemented throughout the system-development life cycle; and risk management processes with clearly defined criteria, risk evaluation, and risk response components.

The NAGF White Paper, titled *Cyber Security Supply Chain Management*,[10] identifies examples for generation entities to consider when developing and implementing their cyber security risk management plans. The NAGF White Paper describes a risk-based approach by which entities conduct an initial screen to determine where additional vendor supply chain risk assessments are required, taking into account the entity's cyber assets impact rating criteria, asset connectivity, vendor connectivity, presence of Transient Cyber Assets and Removable Media, support staff considerations, security awareness/training considerations, and considerations related to Personnel Risk

[7] https://www.nerc.com/pa/comp/Pages/Supply-Chain-Risk-Mitigation-Program.aspx
[8] EPRI, *Supply Chain Risk Assessment Report* (July 2018), https://www.nerc.com/pa/comp/SupplyChainRiskMitigationProgramDL/EPRI_Supply_Chain_Risk_Assessment_Final_Report_public.pdf ("EPRI Interim Report").
[9] NATF, *Cyber Security Supply Chain Risk Management Guidance* (June 20, 2018), https://www.nerc.com/pa/comp/SupplyChainRiskMitigationProgramDL/NATF%20Cyber%20Security%20Supply%20Chain%20Risk%20Management%20Guidance.pdf ("NATF White Paper").
[10] NAGF, *Cyber Security Supply Chain Management White Paper* (2018), https://www.nerc.com/pa/comp/SupplyChainRiskMitigationProgramDL/NAGF%20SC%20White%20Paper%20final.pdf ("NAGF White Paper").

Assessments performed for staff and contractors. If the entity determines that a risk assessment is required, the entity should consider the level of risk posed by the vendor itself and the product or service it provides to determine the appropriate level of supply chain controls required. The NAGF White Paper describes several vendor risk attributes and product/service attributes for the entity to consider in evaluating potential risks.

In response to the Board's fifth resolution, APPA and NRECA prepared a White Paper, titled *Managing Cyber Supply Chain Risk – Best Practices for Small Entities*.[11] The APPA/NRECA White Paper identified several practices for smaller entities with low impact BES Cyber Systems to consider in managing risks from the supply chain. APPA and NRECA identified several best practices for its member entities to consider based on interviews with several smaller entities regarding their supply chain risk management programs. These best practices include, among other things:

- Organizational aspects, such as having senior leadership support for supply chain risk management and conducting enterprise-wide cyber risk assessments;
- Selecting vendors with an eye toward reducing supply chain risk, including using well-known, trusted, and established vendors and considering vendors who have completed third-party accreditation or self-certification of their supply chain practices;
- Placing appropriate limitations surrounding vendor remote access to systems; taking steps to ensure software integrity prior to installation;
- Placing appropriate controls around software updates and patch management.

Order No. 850 Approving the Supply Chain Standards

FERC approved the Supply Chain Standards in Order No. 850, issued on October 18, 2018. While finding that the standards addressed the Commission's directive in Order No. 829 and constitute "substantial progress" in addressing supply chain cyber security risks, the Commission also issued two directives to NERC.

First, noting the significant role that EACMSs play in the protection scheme for medium and high impact BES Cyber Systems, the Commission found that excluding EACMSs from the scope of the Supply Chain Standards presents risks to the cyber security of the BES. Therefore, the Commission directed NERC to develop modifications to the standards to address EACMSs associated with medium and high impact BES Cyber Systems and to submit those modifications within 24 months of the effective date of the final rule.[12]

Second, while continuing to express its concern that excluding certain categories of assets (PACSs and PCAs) from the standards could pose a reliability risk, the Commission found that NERC is taking "adequate and timely steps" to study whether these items should be included in the standards. The Commission accepted NERC's commitment to evaluate the risks of PACSs and PCAs (in addition to low impact BES Cyber Systems) in its study of cyber security supply chain risks and directed NERC to file the final report with FERC upon its completion. The Commission stated that it would be in a better position to consider what further steps, if any, should be taken to protect reliability after receipt of this final report.[13]

Under the approved implementation plan, the Supply Chain Standards will become effective in the United States on the first day of the first calendar quarter that is 18 months after the effective date of the final rule, which is July 1, 2020.

[11] APPA/NRECA, *Managing Cyber Supply Chain Risk – Best Practices for Small Entities* (Apr. 25, 2018), https://www.cooperative.com/programs-services/government-relations/regulatory-issues/documents/supply%20chain%20white%20paper%204-25%20final.pdf ("APPA/NRECA White Paper").
[12] Order No. 850 at P 30.
[13] Order No. 850 at PP 31, 67.

Chapter 1: Supply Chain Risks to the Bulk Electric System and Standards and Practices for Addressing those Risks

Overview

In recognition of the potential risks to BES reliability posed by supply chain vulnerabilities, NERC developed the Supply Chain Standards. These standards will require responsible entities to take additional actions to address cyber security risks associated with the supply chain for BES Cyber Systems.

Consistent with the risk-based approach of the CIP Reliability Standards, and as discussed more fully below, the Supply Chain Standards are applicable only to certain categories of assets. As discussed in subsequent sections of this report, revisions to the Supply Chain Standards may be necessary to help ensure that the standards adequately address supply chain risks related to certain assets that are not within the current scope of the standards.

In addition to the Supply Chain Standards, industry may use other standards and best practices to mitigate potential supply chain risks. Understanding these standards and best practices helps to create a fuller understanding of supply chain risks and the steps that may be taken to help address them in the context of BES reliability.

Supply Chain Risks

Supply chains for information and communications technology and industrial control systems are long and multidimensional, involving numerous parties in countries across the globe. Multiple entities across the globe may participate in the development, design, manufacturing, and delivery of a single purchased product. Global supply chains can provide the opportunity for substantial benefits to consumers, but at the same time, a vulnerability at any link in the chain could result in risks to the end user.

These risks, like the supply chains themselves, are global, multidimensional, and constantly evolving. As observed by FERC, cyber supply chain risks may stem from insertion of counterfeits, unauthorized production, tampering, theft, insertion of malicious software and hardware, and poor manufacturing and development processes.[14] Even well-designed products may have malicious components introduced in the supply chain, and it may prove difficult to identify these components before they are deployed.

Over time, NERC and the industry have developed a more sophisticated understanding of the potential impacts these supply chain risks could have on BES reliability:

- In its 2018 Guidance, the NATF highlighted several real-world events that help demonstrate the risk supply chain vulnerabilities could pose to the electric power industry. These events included the installation of malicious software and theft of project files on a SCADA offering, insertion of unauthorized code on a firewall solution that allowed for the execution of remote procedures, and the alleged insertion of a foreign entity "backdoor" into an anti-virus company's security products.[15]
- In its 2018 White Paper, the APPA and NRECA identified the risks posed by the introduction of malicious code in the supply chain and the employees of vendors who have remote access into their systems as two of the most significant supply chain risks facing their member entities.[16]

[14] *Revised Critical Infrastructure Protection Reliability Standards*, 152 FERC ¶ 61,054, at P 62 (2015).
[15] NATF White Paper at 6.
[16] APPA/NRECA White Paper at 2.

- The *EPRI Interim Report*[17] further highlighted that a compromise in a single vendor's supply chain could have widespread impacts where the vendor supplies a substantial portion of a given product market.[18]

A number of standards and best practices have been developed to address supply chain risks in the electric power industry and other industries. These standards and best practices provide a more complete understanding of supply chain risks and the steps entities may take to mitigate them. Additionally, the Supply Chain Standards provide strong protections for certain categories of high-risk BES Cyber Assets. In implementing the Supply Chain Standards, responsible entities should incorporate some of these industry standards and best practices into their Reliability Standard CIP-013 Requirement R1 supply chain risk management plan(s). NERC staff will work with the CIPC Supply Chain Working Group to develop a guideline to assist entities in selecting which standards and best practices are appropriate.

The Supply Chain Standards, however, do not mandate that entities provide protections for all categories of potentially vulnerable assets. Different categories of assets would present different risks if compromise based on the type of asset and its function. In subsequent sections, this report provides further information on these devices, provides recommendations for the steps entities should take to reduce their exposure to such risks, and, where appropriate, recommends further changes to the Supply Chain Standards to address the risks associated with these specific devices.

Industry Standards and Best Practices to Address Supply Chain Risks

Supply chain concerns are not unique to the electric power industry. Other industries that are sensitive to such risks have developed standards and best practices to mitigate supply chain risks. These standards and best practices, which are discussed in Chapter 3 of the EPRI Interim Report, may provide considerations for mitigating supply chain risks in the electric power industry context as well.

Relevant standards and best practices include the following:

- **Off-premise Supplier Services:** In the government context, where a supplier performs deployments or services for an entity involving federal information systems that are not on government premises, the Federal Risk and Authorization Management Program (FedRAMP) standards apply.
- **Third-Party Accreditation Processes:** Suppliers that follow standards, such as FedRAMP and quality management and information security management standards published by the International Organization for Standardization, use independent third parties to assess their adherence to the standards.
- **Secure Hardware Delivery:** The Energy Sector Control Systems Working Group of the U.S. Department of Energy (DOE) developed Cybersecurity Procurement Language for Energy Delivery Systems that identified controls for hardware delivery to help reduce the risk of compromise during transport.
- **Provenance:** Provenance is the ability to provide traceability in the supply chain processes and supplier relationships. Several standards and guidelines address provenance, including the National Supply Chain Risk Management Practices for Federal Information Systems (NISTIR 7622) published by the National Institute of Standards and Technology (NIST).

[17] EPRI, *Supply Chain Risk Assessment Report* (July 2018), https://www.nerc.com/pa/comp/SupplyChainRiskMitigationProgramDL/EPRI_Supply_Chain_Risk_Assessment_Final_Report_public.pdf ("EPRI Interim Report").

[18] *See generally* EPRI Interim Report at Chapter 2.

- **Threat Modeling:** Threat modeling is a process employed to ensure that all products have a threat model specific to the current development scope of the product as described in International Electrotechnical Commission standard IEC 62443-4-1.
- **Supply Chain Deficiencies Assessment:** 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 as described in NIST SP 800-53. The NATF white paper highlights how such an approach may apply to supply chain risk management for BES cyber systems.[19]
- **External Dependencies Recognition:** One aspect considered by the DOE's Cyber Security Capabilities Maturity Model (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 an entity's ability to highlight and mitigate supply chain risks.
- **Policy for Handling Supplied Products or Services that Do Not Adhere to Procurement Processes:** Entities may use controls to mitigate risks when products or services are supplied that do not adhere to their specific supply chain policies. Such an approach is described by the U.S. Nuclear Regulatory Commission in Appendix B to 10 C.F.R. part 50 in the context of quality assurance. Attachment A of the *NATF Cyber Security Supply Chain Risk Management Guidance* document provides examples of controls used when procuring BES Cyber Assets and services.[20]
- **Unsupported or Open-Sourced Technology Components:** Different processes must be considered to effectively mitigate the risk of legacy or unsupported systems while updating systems or system components. *See* NIST SP 800-53. With respect to open source products, the Open Group[21] has created a set of standards and certification processes titled the "Trusted Technology Provider Standard (O-TTPS) Certification Program" to address supply chain controls for purchasers.
- **Supplier Relationships:** An important aspect of managing suppliers is knowing how to terminate relationships with third parties in a manner that limits the operational impact of losing the product or service. Such considerations are addressed in the Utilities Telecom Council white paper, *Supply Chain Risk Management for Utilities – Roadmap for Implementation.*[22]

While each of these industry standards and best practices can be informative, NERC has identified several best practices as particularly pertinent in addressing the supply chain risks faced by the electric power industry. NERC staff therefore recommends that entities adopt the following practices when developing their supply chain risk management programs:

- **Secure Hardware Delivery:** Many Cyber Assets purchased and deployed on the BES are hardware appliances configured to perform very specific real-time functions; these appliances may possess code that can be manipulated to cause them to potentially affect the reliable operation of the BES. Instituting hardware delivery controls like those described by the DOE Energy Sector Control Systems Working Group may help to reduce the risks if those devices are compromised in transport.
- **Third-Party Accreditation Processes:** Entities should include an independent assessment or third-party accreditation process of their vendors as part of their supply chain risk management strategy as identified in the APPA/NRECA and NATF white papers.[23] NERC will work with stakeholders to develop an accreditation

[19] NATF White Paper at 8–9.
[20] *Id*. at 18.
[21] The Open Group describes itself as a "global consortium that enables the achievement of business objectives through technology standards." The Open Group, https://www.opengroup.org/about-us/who-we-are.
[22] Utilities Telecom Council, Cyber Supply Chain Risk Management for Utilities – Roadmap for Implementation (Apr. 2015), available at https://utc.org/wp- content/uploads/2018/02/SupplyChain2015-2.pdf.
[23] *See* APPA/NRECA White Paper at 16; NATF White Paper at 13.

model for identifying vendors with strong supply chain risk management practices. Such identification would not only help entities increase the level of confidence that vendors providing BES-related products and services are effectively implementing supply chain cyber security controls and measures but also aid compliance with the proposed Reliability Standards. The process(es) for third party accreditation or certification should be developed and submitted to NERC for evaluation. Such process(es) should be implemented within 12 months of the effective date of Reliability Standard CIP-013-1.

- **Threat-Informed Procurement Language:** Entities should tailor their security specifications to the specific risks of their environment. This can be accomplished through threat modeling, which is a process to ensure that all products 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 BES. For example, if an entity is procuring a new remote access system for its medium impact BES Cyber Systems, the threat model should reflect the impact of the remote access system's effect to the BES, and the procurement language for that purchase should be specified according to its specific risk and system-specific vulnerabilities.
- **Processes to Address Unsupported or Open-Sourced Technology Components:** Where patch sources for systems or components are no longer available, entities should develop a plan to mitigate potential risks posed by these unsupported systems. Entities should also implement controls when purchasing open source technology, including responsibility for ongoing support and patching. NERC staff will work with the CIPC Supply Chain Working Group to develop a guideline on appropriate controls.

Using Supply Chain Controls to Mitigate Common-Mode Vulnerabilities: The 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. As a best practice, NERC staff expects entities that have medium or high impact BES Cyber Systems will apply CIP-013-1 Requirement R1 supply chain risk management plans to low impact BES Cyber Systems. Risks of common-mode vulnerabilities can be mitigated if supply chain security practices are applied uniformly across cyber asset types and BES Cyber System impact levels. Further study is needed to determine whether there is any reliability benefit to extending the Supply Chain Standards to low impact BES Cyber Systems.

Additional considerations and guidance for developing robust supply chain risk management programs are provided in the white papers and guidance prepared by the Forums and Associations.

Reliability Standards to Address Supply Chain Risks

As noted above, NERC developed the Supply Chain Standards to address the risks to reliability posed by supply chain concerns. These standards require that responsible entities afford certain supply chain protections to their higher risk assets. This section summarizes the Supply Chain Standards and how the present applicability of those standards fits in the broader risk-based framework of the CIP Reliability Standards.

The Framework of the NERC CIP Reliability Standards

The NERC CIP Reliability Standards provide a risk-based, defense-in-depth approach to securing the BES against cyber and physical security threats. This approach requires BES Cyber Systems or Facilities that could have the highest impact to the grid receive the highest level of protections. In other words, the level of controls required for protecting cyber systems is in proportion to the risk each system presents to reliable operation of the BPS. This approach was used to mitigate the risk of malicious actors targeting specific assets or electric power entities because of their potential impact to the grid.

This risk-based construct requires users, owners, and operators of the BES to identify those cyber systems (referred to as BES Cyber Systems) that could have an adverse effect on BES reliability if lost, compromised, or misused.[24] Using bright-line criteria, responsible entities must then categorize their BES Cyber Systems as high, medium, or low impact based on the risks they present to the grid if lost, compromised, or misused. Once these BES Cyber Systems are identified and categorized, the CIP Reliability Standards require responsible entities to, among other things, establish plans, protocols, and controls to protect those systems against a cyber or physical attack, train personnel on security matters, report security incidents, and recover from security events. The Supply Chain Standards will require responsible entities to take additional actions to address cyber security risks associated with the supply chain for high and medium impact BES Cyber Systems.

NERC Supply Chain Standards

The Supply Chain Standards consist of new Reliability Standard CIP-013-1 (Supply Chain Risk Management) and revised Reliability Standards CIP-005-6 (Electronic Security Perimeter(s)) and CIP-010-3 (Configuration Change Management and Vulnerability Assessments). The Supply Chain Standards focus on the following four security objectives: software integrity and authenticity, vendor remote access protections, information system planning, and vendor risk management and procurement controls.

Collectively, the Supply Chain Standard requirements do the following:

- Reduce the likelihood that an attacker could exploit legitimate vendor patch management processes to deliver compromised software updates or patches to a BES Cyber System (CIP-010-3 Requirement R1 Part 1.6 and CIP-013-1 Requirement R1 Part 1.2 address this concern)
- Address vendor remote access-related threats, including the threat of stolen vendor credentials used to access a BES Cyber System without the responsible entity's knowledge as well as the threat that a compromise at a trusted vendor could traverse over an unmonitored connection into a responsible entity's BES Cyber System (CIP-005-6 Requirement R2 Parts 2.4 and 2.5 and CIP-013-1 Requirement R1 Part 1.2 address this concern)
- Address the risk that responsible entities could unintentionally plan to procure and install vulnerable equipment or software within their information systems or could unintentionally fail to anticipate security issues that may arise due to their network architecture or during technology and vendor transitions (CIP-013-1 Requirement R1 Part 1.1 addresses this concern)
- Address the risk that responsible entities could enter into contracts with vendors who pose significant risks to their information systems as well as the risk that products procured by a responsible entity fail to meet minimum security criteria (CIP-013-1 Requirement R1 Parts 1.1 and 1.2 addresses this concern)
- Address the risk that a compromised vendor would not provide adequate notice of security events and vulnerabilities and related incident response to responsible entities with whom that vendor is connected (CIP-013-1 Requirement R1 Parts 1.2.1 and 1.2.2 addresses this concern)

Consistent with the general risk-based framework of the CIP Reliability Standards, the Supply Chain Standards are subject only to defined categories of Cyber Assets and BES Cyber Systems. **Table 1.1** summarizes the applicability of the Supply Chain Standards.

[24] BES Cyber Systems consist of one or more BES Cyber Assets, which the NERC Glossary defines as follows:

> "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 impact. Each BES Cyber Asset is included in one or more BES Cyber Systems."

Table 1.1: Supply Chain Standard Applicability			
Requirement	**CIP-013-1**	**CIP-005-6 R2.4**	**CIP-010-3 R1.6**
High Impact BES Cyber Systems	✓	✓	✓
Protected Cyber Asset associated with High Impact BES Cyber Systems		✓	
Physical Access Control Systems associated with High Impact BES Cyber Systems			
EACMSs associated with High Impact BES Cyber Systems			
Medium Impact BES Cyber Systems[25]	✓	✓	✓
Protected Cyber Assets associated with Medium Impact BES Cyber Systems		✓	
Physical Access Control Systems associated with Medium Impact BES Cyber Systems			
EACMSs associated with Medium Impact BES Cyber Systems			
Low Impact BES Cyber Systems			

The Supply Chain Standards will require responsible entities to provide strong protections against the risks posed by supply chain compromise for those BES Cyber Systems and Protected Cyber Assets that are subject to the standards. As discussed in subsequent sections of this report, applying these protections more broadly would help reduce the supply chain risks inherent to categories of assets not currently subject to the standards.

Subsequent sections of this report address those assets not presently included in the Supply Chain Standards and the risks associated with those assets if compromised in the supply chain. Chapter 2 addresses EACMSs; Chapter 3 addresses PACS; Chapter 4 addresses low impact BES Cyber Systems; and Chapter 5 addresses PCAs. After evaluating each type of asset and the overall risk environment, NERC makes recommendations for further actions to address those risks.

[25] Reliability Standard CIP-005-6 Requirement R2 Part 2.4 and Reliability Standard CIP-010-3 Requirement R1 Part 1.6 are applicable to "Medium Impact BES Cyber Systems with External Routable Connectivity" and their associated PCA.

Chapter 2: Electronic Access Control or Monitoring Systems

Overview

This chapter addresses reliability risks associated with the supply chain for EACMSs, which are not currently subject to the Supply Chain Standards.

EACMSs are defined in the *NERC Glossary of Terms* as follows:

> ***Electronic Access Control or Monitoring Systems (EACMSs)***: "Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s)[26] or BES Cyber Systems. This includes Intermediate Systems."

The components that make up EACMSs are typically used to control access to, secure, and monitor critical systems on the BES, such as EMS/SCADA and microprocessor-based relays.

Examples of EACMSs include Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, active directory servers, and certificate authorities), security event monitoring systems, and intrusion detection systems.[27] EACMS components include firewalls, routers, layer three switches, intrusion-detection systems, log monitors, and access control systems.

As discussed in this chapter, the CIP Reliability Standards currently contain protections for EACMSs. These protections, however, do not extend to risks specific to the supply chain. Because certain EACMSs components could have a real-time impact on the reliability of the BES if compromised, misused, or rendered unavailable, and consistent with FERC's Order No. 850 directive,[28] NERC staff recommends revising the Supply Chain Standards to address EACMSs. Specifically, NERC staff recommends revising the standard to include those systems that provide electronic access control (excluding monitoring and logging) to high and medium impact BES Cyber Systems.

In the interim, NERC staff expects that entities will identify and assess supply chain vulnerabilities when procuring and configuring various cyber asset types associated with EACMSs that provide electronic access (excluding monitoring and logging) to high and medium impact BES Cyber Systems. That is, an entity should perform a comprehensive CIP-013-1 Requirement 1 Part R1.1 risk identification and assessment process to consider the potential impact of EACMSs within the entity's operating environment.

Current CIP Reliability Standard Protections for EACMSs

NERC has existing Reliability Standards that are applicable to EACMSs:

- Reliability Standard CIP-003-6 requires responsible entities to have policies that address cyber security for BES Cyber Systems, including EACMSs for high and medium impact BES Cyber Systems and electronic access controls for low impact BES Cyber Systems.
- Reliability Standard CIP-004-6 requires responsible entities to implement one or more cyber security training program(s) appropriate to individual roles, functions, or responsibilities for those individuals that have access to high and medium impact BES Cyber Systems and associated EACMSs. It also requires responsible entities to implement one or more documented personnel risk assessment program(s) to attain and retain authorized electronic or authorized unescorted physical access to high and medium impact BES Cyber Systems and associated EACMSs. It further requires entities to implement one or more access management program(s)

[26] The NERC Glossary defines an Electronic Security Perimeter (ESP) as "[t]he logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol."
[27] *See* Background, Reliability Standard CIP-002-5.
[28] Order No. 850 at P 30.

and access revocation program(s) applicable to high and medium impact BES Cyber Systems and associated EACMSs.

- Reliability Standard CIP-006-6 requires responsible entities to implement one or more documented physical security plan(s) and documented visitor control program(s) for high and medium impact BES Cyber Systems and associated EACMSs.
- Reliability Standard CIP-007-6 requires responsible entities to implement one or more documented processes(s) that address enabling and disabling ports and services for high and medium impact BES Cyber Systems and associated EACMSs. It also requires entities to implement one or more documented process(es) that address patch management and malicious code prevention applicable to high and medium impact BES Cyber Systems and associated EACMSs. It further requires entities to implement one or more documented process(es) that address security event monitoring and logging and system access controls applicable to high and medium impact BES Cyber Systems and associated EACMSs.
- Reliability Standard CIP-009-6 requires responsible entities to implement one or more documented recovery plan(s) for high and medium impact BES Cyber Systems and associated EACMSs. It also requires those entities to test and maintain the recovery plan(s).
- Reliability Standard CIP-010-2 requires responsible entities to implement one or more documented processes(s) that address configuration change management and configuration monitoring for high and medium impact BES Cyber Systems and associated EACMSs. It also requires responsible entities to perform vulnerability assessments applicable to high and medium impact BES Cyber Systems and associated EACMSs.
- Reliability Standard CIP-011-2 requires responsible entities to implement one or more documented information protection program(s) and BES Cyber Asset reuse and disposal process(es) for high and medium impact BES Cyber System and associated EACMSs.

These requirements work together to form a cohesive security protection for deployed EACMSs; however, they do not address the concerns specific to the supply chain discussed below.

Potential BES Risks Associated with EACMSs due to Supply Chain Concerns

EACMSs are potentially vulnerable to risks from the supply chain. If compromised, misused, or rendered unavailable, EACMS components could have a real-time impact on the reliability of the BES. The risks posed by supply chain vulnerabilities depend in large part on the specific configuration of the EACMSs, where the EACMS is deployed (i.e., at low, medium, or high impact BES Cyber System), and the extent to which certain compensating measures are employed.

EACMSs can consist of systems that perform electronic access control and systems that perform monitoring and logging functions. The reliability risks associated with compromise of electronic access control systems are higher than those associated with monitoring and logging functions.

If a component of an electronic access control EACMSs were to be compromised in the supply chain, such as through the introduction of an unauthorized “backdoor,” a malicious actor could access (or bar authorized users from accessing) systems that directly affect the operation of the BES. If the compromised EACMS controls electronic access to a medium or high impact BES Cyber System, this compromise could negatively impact the reliability of the BES.

If a component of a monitoring EACMS was compromised in the supply chain, such as through the introduction of malicious code, it could impact the ability of the owner to quickly detect, alert to, and respond to a cyber attack. It can also result in real-time access alarms being masked from those that are actively assessing reliability. If a component of a logging EACMS was compromised, it could hinder the ability to perform forensic analysis after active or attempted attacks.

Where EACMSs are configured on a single platform, the risk to all services, including access control, monitoring, and logging, share a single higher risk level if the management plane[29] of the single device is compromised or misused. This is because such devices control access to critical systems from a single point. Services required for access, authentication, monitoring, logging, detection, and alerting could be altered or misconfigured, blinding operators and security personnel to potential unauthorized access and introduction of malicious code to BES Cyber Systems within an ESP.

The risks posed by vendor-initiated remote access sessions, whether through interactive remote access or system-to-system remote access, also represent a significant vector for attack into the associated BES Cyber System through the EACMS.

In evaluating the risks posed by supply chain compromise of EACMSs, NERC staff considered that half of the market share of substation networking equipment is held by only two vendors, one of which has a 55 percent world-wide enterprise network market share in the corporate environment of many industries, including the electric power industry.[30] If a major vendor unknowingly supplied compromised networking equipment, and the compromise was then exploited to allow access to EACMSs controlling electronic access to medium or high impact BES Cyber Systems, the compromise could have widespread negative impacts on reliability.

The potential risks of supply chain compromise described above can be mitigated in part by technical controls, some of which are addressed in the CIP Reliability Standards, while others could be addressed in an entity's policies and procedures. For example, strict authorization and authentication, up to and including multi-factor authentication, can be used to limit the risk posed by local or remote access to the management services of an EACMS by owner or vendor personnel. Other technical controls that could be put in place to secure access and communications include the following: implementing strong password policies; implementing role-based access control; using authentication, authorization, and accounting services; implementing access control lists; encrypting remote access sessions; and using separate secured virtual local area networks for data and management traffic. Testing, verification, and validation of the architecture, configuration, and management access of EACMSs can also help ensure that EACMSs are implemented as designed, meet the expected security controls objectives, and protect BES Cyber Systems within a defined ESP.

While the technical controls mentioned above can provide some protections against certain compromises introduced in the supply chain, they do not address all potential risks. Given the potential adverse impacts that could be caused by a compromised EACMS, it is important to identify and assess supply chain vulnerabilities when procuring and configuring these systems.

Recommended Actions to Address the Risks

Noting that "the vulnerabilities associated with EACMS are well understood and appropriate for mitigation," FERC directed NERC in Order No. 850 to revise the Supply Chain Standards to include EACMSs.[31]

Upon evaluation of the supply chain-related risks associated with EACMSs, particularly those posed by compromise of electronic access functions, NERC staff recommends that the Supply Chain Standards be modified to include EACMSs that perform electronic access control for high and medium BES Cyber Systems.

Consistent with the risk-based framework of the CIP Reliability Standards, any future revision to the Supply Chain Standards should account for the fact that EACMSs present different risks based on the functions that they perform.

[29] "Management plane" refers to the part of the system that configures, monitors, and provides management, monitoring, and configuration services to all layers of the system.
[30] EPRI Interim Report, at Chapter 2.
[31] Order No. 850 at P 30.

As described above, the BES Cyber Systems that perform electronic access control would, if compromised, present a higher risk to reliability than a compromise of monitoring or logging systems. This is because these access control systems serve as "gatekeepers" to critical systems. Work is currently underway on Project 2016-02 Modifications to CIP Standards[32] to develop new defined terms that separate out EACMS functions so that appropriate controls can be placed around appropriate risks.

In the interim, NERC staff expects that entities will identify and assess supply chain vulnerabilities when procuring and configuring various cyber asset types associated with EACMSs. Various risk assessment techniques are provided in the APPA/NRECA and NATF white papers. For example, entities should perform a comprehensive risk identification and assessment process under Reliability Standard CIP-013-1 Requirement R1.1 that would, at a minimum, consider the following EACMS factors within the entity's operating environment:[33]

- Identify the components that comprise the EACMSs (i.e., specific cyber asset types)
- Identify the vendor(s) for each EACMS device type
- Identify the functions each EACMS device type performs to protect reliability (i.e., firewall, router, switch, etc.)
- Identify and prioritize: the risks presented by each EACMS device type if compromised (e.g., a compromised firewall could allow unauthorized or malicious traffic[34]); and informed potential mitigating circumstances (e.g., logging systems are primarily used for after-the-fact analysis rather than real-time protection)
- Assess the identified risks posed by each device type
- Develop potential strategies or recommendations to address and mitigate each identified risk
- Include recommendations to address EACMS risks in the process(es) used to procure BES Cyber Systems that would address identified risks specific to CIP-013-1 Requirement R1 Parts R1.2.1 through R1.2.6, as applicable, and identify existing or planned vendor mitigation strategies or procedures that address each identified risk as follows:
  - Specific to CIP-013-1 Requirement R1 Parts R1.2.3 and R1.2.6, include recommendations relative to coordinated controls between the entity and applicable vendors associated with CIP-005-6 (Parts 2.4 and 2.5) for managing active vendor remote access sessions to and/or through EACMS cyber asset types
  - Specific to CIP-013-1 Requirement R1 Part R1.2.5, include recommendations specific to planned methods associated with CIP-010-3 (Part 1.6) for verifying the identity of software sources and integrity of software obtained from such sources prior to application to EACMS cyber asset types
  - Specific to CIP-013-1 Requirement R1 Part R1.2.6, include recommendations for controls specific to identified risks associated with compromised vendor-initiated remote access sessions

Reliability Standard CIP-013-1 Requirement 1 Part 1.2.5 addresses verifying the integrity and authenticity of software installed on particular assets. This verification helps to ensure that the software installed on high and medium BES Cyber Systems is not modified prior to installation without awareness of the software supplier and is not a counterfeit piece of software.

In the EACMS context, this software enables controls and monitoring. This highlights the importance of verification, especially for the "gatekeeping" monitoring assets. When the Supply Chain Standards are modified as recommended,

[32] Project 2016-02 Modifications to CIP Standards, http://www.nerc.com/pa/Stand/Pages/Project%202016-02%20Modifications%20to%20CIP%20Standards.aspx.

[33] This list is provided as an example of considerations for the CIP-013-1 Requirement R1.1 risk identification and assessment process, but it should not be considered an exhaustive or prescriptive list of all the variables that should be considered by each entity for EACMS within its unique operating environment.

[34] *See, e.g.*, EPRI Interim Report at 4-4.

the integrity and authenticity of the software installed on the particular assets that make up the system for monitoring and controlling would be covered by Reliability Standard CIP-013 Requirement 1 Part 1.2.5. This process would, in turn, support the verification required under Reliability Standard CIP-010-3, Requirement 1 Part 1.6. By verifying the integrity and authenticity of their EACMS software, entities can reduce the risk that software installed on the BES Cyber Systems (not just EACMSs, but all BES Cyber Systems) could be modified prior to installation without awareness of the software supplier or be a counterfeit piece of software.

Chapter 3: Physical Access Control Systems

Overview

This chapter addresses reliability risks associated with the supply chain for PACSs, which are not currently subject to the Supply Chain Standards.

PACSs are defined in the NERC *Glossary of Terms* as follows:

> ***Physical Access Control Systems (PACSs)***: "Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s),[35] exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers."

The systems that make up PACSs are often used to control and monitor physical access to Facilities and systems on the BES where BES Cyber Systems reside. These include physical intrusion-detection systems, log monitors, and systems to control physical access. Examples of PACSs cyber asset types include authentication servers, card systems, and badge control systems.[36]

As discussed in this chapter, the CIP Reliability Standards currently contain protections for PACSs. These protections, however, do not extend to supply chain risk management issues. To address these risks, NERC staff recommends revising the Supply Chain Standards to address those systems that provide physical access control, excluding alerting and logging. In the interim, NERC staff expects that entities will identify and assess supply chain vulnerabilities when procuring and configuring various cyber asset types associated with PACSs. That is, an entity should perform a comprehensive Reliability Standard CIP-013-1 Requirement 1 Part R1.1 risk identification and assessment process to consider the potential impact of PACSs within the entity's operating environment.

Current CIP Protections for PACSs

NERC has existing Reliability Standards that are applicable to PACSs listed as follows:

- Reliability Standard CIP-003-6 requires responsible entities to have policies that address physical security for BES Cyber Systems, including PACSs for high and medium impact BES Cyber Assets and physical security controls for low impact BES Cyber Systems.
- Reliability Standard CIP-004-6 requires responsible entities to implement one or more cyber security training program(s) appropriate to individual roles, functions, or responsibilities for those individuals that have access to high and medium impact BES Cyber Systems and associated PACSs. It also requires entities to implement one or more documented personnel risk assessment program(s) to attain and retain authorized electronic or authorized unescorted physical access to high and medium impact BES Cyber Systems and associated PACSs. It further requires entities to implement one or more access management program(s) and access revocation program(s) applicable to high and medium impact BES Cyber Systems and associated PACSs.
- Reliability Standard CIP-006-6 requires responsible entities to implement one or more documented physical security plan(s) and documented visitor control program(s) for high and medium impact BES Cyber Systems and associated PACSs.
- Reliability Standard CIP-007-6 requires responsible entities to implement one or more documented processes(s) that address enabling and disabling ports and services for high and medium impact BES Cyber

[35] A PSP is defined in the NERC Glossary as "[t]he 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."
[36] *See* Background, Reliability Standard CIP-002-5.

Systems and associated PACSs. It also requires entities to implement one or more documented process(es) that address patch management and malicious code prevention applicable to high and medium impact BES Cyber Systems and associated PACSs. It further requires entities to implement one or more documented process(es) that address security event monitoring and logging and system access controls applicable to high and medium impact BES Cyber Systems and associated PACSs.

- Reliability Standard CIP-009-6 requires responsible entities to implement one or more documented recovery plan(s) for high and medium impact BES Cyber Systems and associated PACSs. It also requires those entities to test and maintain the recovery plan(s).
- Reliability Standard CIP-010-2 requires responsible entities to implement one or more documented processes(s) that address configuration change management for high and medium impact BES Cyber Systems and associated PACSs. It also requires entities to perform vulnerability assessments applicable to high and medium impact BES Cyber Systems and associated PACSs.
- Reliability Standard CIP-011-2 requires responsible entities to implement one or more documented information protection program(s) and BES Cyber Asset reuse and disposal process(es) for high and medium impact BES Cyber Systems and associated PACSs.

These requirements work together to form a cohesive security protection for deployed PACSs; however, supply chain concerns still exist and are further discussed in this chapter.

Potential BES Risks Associated with PACSs Due to Supply Chain Concerns

PACSs are potentially vulnerable to risks from the supply chain. If compromised, misused, or rendered unavailable, PACS components could have a real-time impact on the reliability of the BES. The risks posed by supply chain vulnerabilities depend in large part on the specific configuration of the PACS, where the PACS is deployed (i.e., at low, medium, or high impact BES Cyber System), and the extent to which certain compensating measures are employed.

Depending on specific configurations, PACSs could have a real-time impact on the reliability of the BES if compromised, misused, or rendered unavailable. Given this potential impact, it is important to consider supply chain vulnerabilities when procuring and configuring these systems.

A number of methods and systems may be used to control, monitor, and log physical access to BES Cyber Systems. These methods and systems are typically supplied at least in part by third parties and are thus vulnerable to compromises introduced in the supply chain.

Methods of physical access control include the following:

- **Card Key:** A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- **Special Locks:** These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.
- **Security Personnel:** Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.
- **Other Authentication Devices:** Biometric, keypad, token, or other equivalent devices that control physical access into the Physical Security Perimeter (PSP).

- Methods to monitor physical access include the following:
  - **Alarm Systems:** Systems that alarm to indicate interior motion or when a door, gate, or window has been opened without authorization. These alarms must provide for notification within 15 minutes to individuals responsible for response.
  - **Video Recording:** Electronic capture of video images of sufficient quality to monitor activity at or near PSPs and/or physical security access points.
  - **Human Observation of Access Points:** Monitoring of physical access points by security personnel who are also controlling physical access.

Methods to log physical access include the following:

- **Computerized Logging:** Electronic logs produced by the responsible entity's selected access control and alerting method.
- **Video Recording:** Electronic capture of video images of sufficient quality to determine identity.
- **Manual Logging:** A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access.

Similar to EACMSs, the PACS cyber systems that perform physical access control present a higher risk than monitoring and logging systems. A compromise of PACs could allow access to systems that directly affect the operation of the BES, potentially allowing a threat source to negatively impact the BES reliability. Examples of scenarios applicable to compromised PACS components (such as those described above) include, but are not limited to, the following:

- A combined cyber/physical attack on one or more high impact BES Cyber Systems and their host Facilities, where external control of previously compromised PACS elements could allow external threat actors to obtain undetected physical access to Control Centers and other Facilities that control or operate significant portions of the grid. Once inside the PSP, threat actors could detain, subvert, or eliminate the system operators and take physical control of the BES Cyber Systems.
- Misuse, degradation, or destruction of PACS access control components could also allow internal threat actors to take adverse actions on BES Cyber Systems without detection. Such a scenario may precede a physical attack or support a subsequent cyber attack.

While not a specific supply chain risk, there is also a high potential for insider collusion with external threat actors to ensure PACS supply chain compromises are activated prior to a physical attack.

Compromise of the cyber systems that perform monitoring, while not presenting as high of a risk, could impact the ability to quickly analyze an attack and may mask real-time alarms for access from those that are actively assessing reliability. Compromised PACS monitoring systems may also eliminate the entity's ability to detect illicit access to Facilities and their associated BES Cyber Systems. A physical or cyber attack may be preceded by loss of capability to monitor for unauthorized access and to issue alarms or alerts to monitoring personnel, which may lengthen response times and allow threat actors to succeed in their attacks.

Compromise of logging systems would present a much smaller risk as these systems are used primarily to perform forensic analysis after active and potential attacks. Compromised PACS logging systems, however, could prevent accurate forensic analysis and potentially hamper recovery or restoration efforts.

The potential risks of supply chain compromise described above can be mitigated in part by controls, some of which are addressed in the CIP Reliability Standards while others can be addressed in entity policies and procedures. For example, strict operational or procedural controls can be used to limit the risk posed by unauthorized physical access

to BES Cyber Systems. Other controls that could be put in place to restrict access include implementing a completely enclosed "six-wall" boundary and implementing two or more different and complementary physical access controls. Testing, verification, and validation of the architecture, configuration, and management access of PACSs can also help ensure that PACSs are implemented as designed, meet the expected security controls objectives, and protect BES Cyber Systems within a defined PSP.

In addition, a threat actor must be physically present at the facility in order to exploit the vulnerability created by a compromised PACS system. A threat actor may also need to bypass several physical access or monitoring controls that have not been compromised in order to gain access.

However, given the potential adverse impacts that could be caused by compromised PACSs, particularly compromised access control systems, it is important to identify and assess supply chain vulnerabilities when procuring and configuring these systems.

Recommended Actions to Address the Risks

Upon evaluation of the supply chain-related risks associated with PACSs, particularly those that control physical access, NERC staff recommends that the Supply Chain Standards be modified to include PACSs that perform physical access controls for high and medium BES Cyber Systems.

Consistent with the risk-based framework of the CIP Reliability Standards, any future revision(s) to the Supply Chain Standards should account for the fact that PACSs present different risks based on the functions that they perform. As described above, the cyber systems that perform physical access control would, if compromised, present a higher risk to reliability than a compromise of alerting and logging systems.

In the interim, NERC staff expects that entities will identify and assess supply chain vulnerabilities when procuring and configuring various cyber asset types associated with PACSs. Various risk assessment techniques are provided in the APPA/NRECA and NATF White Papers. For example, a comprehensive risk identification and assessment process under Reliability Standard CIP-013-1 Requirement R1.1 would, at a minimum, consider the following PACSs factors within the entity's operating environment:[37]

- Identify the components that comprise the PACSs (i.e., specific cyber asset types), including, but not limited to, the following:
  - Servers
  - Workstations
  - Cameras and other surveillance equipment
  - Access control cyber asset components
  - Monitoring components
  - Logging components
- Identify the vendor(s) for each PACS device type
- Identify the functions each PACS device type performs to protect reliability (e.g., authorizing and granting access, detection, response, monitoring, logging, etc.)

[37] This list is provided as an example of considerations for the CIP-013-1 Requirement R1.1 risk identification and assessment process, but it should not be considered an exhaustive or prescriptive list of all the variables that should be considered by each entity relative to supply chain risk management risks associated with PACS cyber asset types within its unique operating environment.

- Identify and prioritize the risks presented by each PACS device type if compromised (i.e., a compromised access authorization system could allow unauthorized or malicious access)
- Identify potential mitigating circumstances (i.e., logging systems are primarily used for after-the-fact analysis rather than real-time protection)
- Assess the identified risks posed by each device type
- Develop potential strategies and/or recommendations to address and mitigate each identified risk
- Include recommendations to address PACS risks the process(es) used to procure BES Cyber Systems that would address identified risks specific to CIP-013-1 Requirement R1 Parts R1.2.1 through R1.2.6, as applicable, and identify existing or planned vendor mitigation strategies or procedures that address each identified risk:
  - Specific to CIP-013-1 Requirement R1 Parts R1.2.1, R1.2.2, and R1.2.4, entities may include physical security mitigation plans to minimize threats associated with such notifications and disclosures (e.g., increase guard force personnel to provide manual physical access controls at PSP Entry Points until such identified vulnerabilities are addressed)
  - Specific to CIP-013-1 Requirement R1 Parts R1.2.3 and R1.2.6, integrate recommendations relative to coordinated controls between the entity and applicable vendors for managing physical access and active vendor remote access sessions to and/or through PACS cyber asset types
  - Specific to CIP-013-1 Requirement R1 Part R1.2.5, integrate recommendations specific to planned methods associated with CIP-010-3 (Part 1.6) for verifying the identity of software sources and integrity of software obtained from such sources prior to application to PACS cyber asset types
  - Specific to CIP-013-1 Requirement R1 Part R1.2.6, integrate recommendations for controls specific to identified risks associated with compromised vendor-initiated remote access sessions

Chapter 4: Low Impact BES Cyber Systems

Overview

Under the CIP-002 standard, responsible entities are required to categorize their BES Cyber Systems as either high, medium, or low impact using the bright-line impact rating criteria (IRC) outlined in Attachment 1 to the standard, as follows:

- Section 1 identifies the IRC for high impact BES Cyber Systems. The IRC is limited to BES Cyber Systems associated with four categories of Control Centers (*see* IRC 1.1–1.4).
- Section 2 identifies medium impact BES Cyber Systems associated with Control Centers, generation and transmission Facilities as well as specified remedial action and load shedding schemes (*see* IRC 2.1–2.13).
- Section 3 identifies BES Cyber Systems located at all other BES assets that were not previously identified under Sections 1 or 2. These low impact BES Cyber Systems are associated with smaller BES Facilities, such as Control Centers, generation and transmission Facilities, systems and Facilities critical to system restoration, specified transmission protection systems, including certain system protection and restoration systems owned by Distribution Providers (*see* IRC 3.1–3.6).

The Supply Chain Standards are applicable only to high and medium impact BES Cyber Systems.

In 2016, registered entities were requested to report the number of BES assets (e.g., Control Center, backup Control Center, substation, generation plant, etc.) identified in CIP-002-5.1 Requirement R1, Attachment 1 with high, medium, and low impact BES Cyber Systems as of July 1, 2016. Based on the results, NERC determined that approximately 21 percent of NERC registered entities own high or medium impact BES Cyber Systems; the remainder own only low impact BES Cyber Systems. It is important to note, however, that these survey results do not represent the percentage of assets containing low impact BES Cyber Systems. Many of the 21 percent of registered entities that own and/or operate high and medium impact BES Cyber Systems also own and operate a significant number of low impact BES Cyber Systems. Thus, additional data is needed to gauge the percentage of assets containing low impact BES Cyber Systems that are owned or operated by registered entities that also own medium and high impact BES Cyber Systems. Further study will help assess the residual risk to BES reliability associated with entities that own only low impact BES Cyber Systems.

NERC staff recommends further study of this issue as discussed below to determine whether the inclusion of low impact BES Cyber Systems with External Routable Connectivity should be considered while taking into account the number and nature of such low impact BES Cyber Systems, the benefits of including such systems in the Supply Chain Standards, and the associated costs of extending CIP-013 to cover these systems. While this work is underway, NERC staff recommends that the CIPC Supply Chain Working Group develop a guideline to assist entities in applying supply chain risk management plans to low impact BES Cyber Systems.

Supply Chain Risks Associated with Low Impact BES Cyber Systems

Low impact BES Cyber Systems are generally comprised of the same types of cyber assets as those in high and medium impact BES Cyber Systems and are therefore subject to similar supply chain risks, but individually present a lower risk to BES reliability if they are compromised. For example, these supply chain risks would include those posed by the introduction of malicious code in the supply chain and the employees of vendors who have remote access into their systems. These two risks have been cited by NRECA and APPA as two of the most significant supply chain risks facing their member entities.[38]

[38] APPA/NRECA white paper at 2.

The applicability of the Supply Chain Standards is consistent with the overall framework of the CIP Reliability Standards discussed above, which is to focus entity attention and resources on those assets that could pose the greatest risks to reliability if they were to be compromised. Low impact BES Cyber Systems are typically associated with isolated, smaller Facilities that are not currently subject to most[39] of the CIP Reliability Standards. Although compromise of an individual low impact BES Cyber System would, by definition, not pose a risk to reliability, the *EPRI Interim Report*[40] highlighted the potential negative impacts on reliability if numerous low impact BES Cyber Systems were compromised. This could happen if a major vendor with sizeable market share unintentionally supplied a compromised product to a sizeable percentage of the industry, and a malicious actor then exploited the single configuration-based vulnerability across a number of devices. Viruses, worms, and malware programs target "common mode vulnerabilities" in this manner.

To better understand this potential risk, EPRI conducted a market data analysis. This analysis consisted of assessing the product/manufacturer types used on the BES for SCADA/control systems, network and telecommunications, and operating systems. While this analysis does not break out the percentages of vendors supplying only low impact BES Cyber Systems, the information is useful as a general representation of the current state of the market. EPRI's analysis showed that two vendors, when combined, have half of the market share of substation networking equipment. It also showed the dominance of the Windows operating system in deployed systems. A further look at the data showed that a significant number of systems were running outdated (unsupported) operating systems and/or open operating systems. Also, two vendors, when combined, hold 82 percent of the existing deployment of energy management systems. By contrast, EPRI determined that no single vendor in the market for remote terminal units exceeded 20 percent market share.[41]

The risk to reliability posed by the mass exploit of a "common mode vulnerability" introduced in the supply chain for low impact BES Cyber Systems may be mitigated by several factors. First, while many CIP Reliability Standards are not applicable to low impact BES Cyber Systems, applying basic cyber hygiene practices could limit the reach and impact of such an event. Examples of such practices include application whitelisting, patching, minimizing domain or local administrative privileges, and disabling local administrative accounts where they are unnecessary. Second, the Supply Chain Standards are expected to have a positive impact on the overall market for electric industry goods and services, which would ultimately reduce the supply chain risks associated with low impact BES Cyber Systems. As noted in the APPA/NRECA White Paper, smaller entities that own only low impact BES Cyber Systems often purchase from the same, well-established vendors that larger entities with higher risk assets use. As larger entities with medium and high impact BES Cyber Assets demand certain supply chain practices from vendors, vendors may choose to apply those supply chain practices to all of their products sold to the electric power industry.[42] The Supply Chain Standards would therefore provide protections to low impact BES Cyber Assets even though the standards do not specifically cover them.

There is a second potential risk associated with low impact BES Cyber Systems, particularly those owned by an entity that also owns high or medium BES Cyber Systems. The risk is that a malicious actor could target the supply chain for a low impact BES Cyber System and, assuming no other controls were in place, exploit that vulnerability to attack other systems owned by the same entity, including high and medium BES Cyber Systems at larger and more critical BES Facilities including Control Centers, generation plants, and transmission Facilities.

[39] Effective January 1, 2020, Reliability Standard CIP-003-7 will be applicable to low impact BES Cyber Systems; Requirements R1.2 and R2 will require certain programmatic, physical, and electronic access protections.

[40] EPRI, *Supply Chain Risk Assessment Report* (July 2018), https://www.nerc.com/pa/comp/SupplyChainRiskMitigationProgramDL/EPRI_Supply_Chain_Risk_Assessment_Final_Report_public.pdf ("EPRI Interim Report").

[41] For more information on the specific market assessment, refer to the EPRI Interim Report at Chapter 2.

[42] APPA/NRECA white paper at 9-10.

This risk is thought to be mitigated, in large part, by entity supply chain practices. During the standard development process for the Supply Chain Standards, several procurement professionals stated that, other than for specific projects, they typically order cyber asset types without regard to the final destination. For example, orders may be placed for warehouse stock. A comprehensive Reliability Standard CIP-013-1 Requirement R1 supply chain risk management procurement plan that addresses all cyber asset types used by a registered entity in its high and medium impact BES Cyber Systems would also reduce comparable supply chain cyber security risks for assets deployed in low impact BES Cyber Systems.

Recommended Actions to Address the Risks

As a best practice, NERC staff expects entities that have medium or high impact BES Cyber Systems will voluntarily apply CIP-013-1 Requirement R1 supply chain risk management plans to low impact BES Cyber Systems. This would help reduce the residual risks arising from the supply chain to those systems. Any cyber asset types identified as exclusive to low impact BES Cyber Systems should be evaluated on a case-by-case basis to determine the impact and extent of any supply chain risk management risks, which, if realized, could present a significant threat to the reliability of the BES. For entities that own both low and medium or high impact BES Cyber Systems, applying such practices to all assets regardless of destination would not only reduce the risks to its low impact BES Cyber Systems, but would also help streamline procurement and deployment processes generally.

NERC staff expects entities that own only low impact BES Cyber Systems to develop supply chain risk management programs tailored to their unique risk profiles and priorities. The APPA/NRECA white paper[43] provides considerations for smaller entities in developing such programs. NERC staff will work with the CIPC Supply Chain Working Group to develop a guideline to assist entities in voluntarily applying supply chain risk management plans to low impact BES Cyber Systems.

For several reasons, NERC staff does not recommend revising the Supply Chain Standards to require protections for all low impact BES Cyber Systems at this time. The risk-based approach used in the CIP Reliability Standards generally, and the Supply Chain Standards specifically, enables responsible entities to prioritize controls for high and medium impact BES Cyber Assets. High and medium impact BES Cyber Systems as categorized in CIP-002 generally describe assets that are critical to interconnected operations, including transmission operations, reliability coordination, and balancing functions. CIP-013-1 provides responsible entities with flexibility for determining appropriate steps for addressing supply chain cyber security risks for low impact BES Cyber Systems. This approach provides an opportunity for industry to take measured steps to address complex supply chain cyber security risks based on their system needs. The reliability benefit of a measured and prioritized approach is that it is more manageable for responsible entities to focus the development of their plans, processes, and controls on the smaller subset of cyber assets that includes the most significant cyber assets.

As described above, the implementation of the Supply Chain Standards is expected to have broader, positive impacts on both vendor and entity supply chain practices. Practices adopted by vendors to satisfy purchasers of assets deployed in high and medium BES Cyber Systems may ultimately be extended to assets deployed in low impact BES Cyber Systems as well. Following implementation of the Supply Chain Standards, NERC may find that there is no incremental reliability benefit associated with extending the Supply Chain Standards to low impact BES Cyber Systems.

Further, extending the Supply Chain Standards to low impact BES Cyber Systems could have unintended effects that may inadvertently increase the risk of common-mode vulnerabilities due to the reduction in diversity of vendors. For example, some vendors may choose not to provide small entities with the services required by the standards, such

[43] APPA/NRECA, *Managing Cyber Supply Chain Risk – Best Practices for Small Entities* (Apr. 25, 2018), https://www.cooperative.com/programs-services/government-relations/regulatory-issues/documents/supply%20chain%20white%20paper%204-25%20final.pdf ("APPA/NRECA White Paper").

as providing notification of vendor identified incidents that pose a cyber risk to the small entity, and owners of low impact BES Cyber Systems may thus have a smaller pool of potential vendors from which to choose. This smaller vendor pool could result in an increased risk that a common mode vulnerability in any one vendor's products or services could affect a substantial number of low impact BES Cyber Systems. Further study is necessary to determine the costs, reliability benefits, and potential unintended consequences of extending the Supply Chain Standards to low impact BES Cyber Systems.

Nevertheless, given the potential risk of a common mode vulnerability affecting numerous low impact BES Cyber Systems, NERC staff recommends further study to determine whether low impact BES Cyber Systems with External Routable Connectivity should be included within the scope of CIP-013. External Routable Connectivity is defined in the NERC Glossary as follows:

> "The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection."

Given this connectivity, these low impact BES Cyber Systems may pose a higher risk that could warrant mandatory supply chain protections.

First, NERC staff will propose to the Board a Request for Data or Information under Section 1600 of the NERC Rules of Procedure to obtain more information about the nature and number of BES Cyber Systems currently in use. NERC staff will work with the CIPC Supply Chain Working Group to determine the appropriate scope of the request. NERC staff expects that the request would address, at a minimum, the following considerations:

- The approximate total number of BES Cyber Assets in high/medium impact BES Cyber System(s): Of this number, the approximate number that have External Routable Connectivity
- The approximate total number of BES Cyber Assets in low impact BES Cyber Systems: Of this number, the approximate number that have External Routable Connectivity
- Questions to determine incremental costs and potential benefits to extend CIP-013 to low impact BES Cyber Systems with External Routable Connectivity:
    - The costs and potential benefits for entities that have high/medium impact BES Cyber Systems
    - The costs and potential benefits for entities that have only low impact BES Cyber Systems

Following the collection of the data, NERC staff will provide the results of the data analysis to industry.

Second, NERC staff will monitor the issue through the use of industry surveys and questionnaires following the implementation of the Supply Chain Standards to determine whether new information supports modifying the standards to include low impact BES Cyber Systems with External Routable Connectivity and to determine if there is consistent application of the criteria in CIP Reliability Standards that differentiate medium impact BES Cyber Systems from low impact. This new information would include actual market and entity practices following implementation of the Supply Chain Standards and the extent to which these practices may help reduce risks to reliability stemming from the supply chains for low impact BES Cyber Systems, including those with External Routable Connectivity. With this information, NERC and its stakeholders may make an informed analysis of whether mandatory requirements for all or a subset of low impact BES Cyber Systems are appropriate while taking into account the costs, expected benefits, and all other relevant considerations. To encourage full and frank industry participation, NERC Staff recommends that these surveys be completed independently of any mandatory compliance monitoring or enforcement process.

Chapter 5: Protected Cyber Assets

Overview

This chapter addresses the supply chain risk management risks posed by PCAs, which are currently subject to only a limited subset of the Supply Chain Standards.

PCAs are defined in the NERC Glossary of Terms as follows:

> ***Protected Cyber Assets (PCAs)***: "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."

Since there is a wide range of assets that fall under the category of PCAs, it is not possible to clearly define a general risk to the BES in the event they are compromised due to supply chain vulnerabilities. NERC staff recommends that entities, as a best cyber security practice, evaluate each PCA type on a case-by-case basis to identify any specific risks associated with supply chain risk management. This evaluation will allow each entity to determine whether supply chain risk management procurement processes are needed to mitigate the risk to associated BES Cyber Systems. NERC staff will work with the CIPC Supply Chain Working Group to develop a guideline to assist entities in evaluating their PCAs to determine what, if any, additional supply chain protections are needed. NERC staff will also work with the CIPC Supply Chain Working Group to determine whether additional data should be collected on PCAs, as an extension of the Section 1600 data request to be prepared on low impact BES Cyber Assets.

Potential BES Risks Associated with PCAs due to Supply Chain Concerns

It is difficult to provide a general assessment of the risks that supply chain-compromised PCAs could present to the BES. By definition, PCAs do not represent an immediate 15-minute adverse impact to the reliability of the BES. PCA types, however, are sometimes identical to those cyber asset types identified as BES Cyber Assets. As a result, supply chain risk management practices should be highly dependent on the specific function of the PCA in question and the exposure risk to the BES Cyber Systems in the same ESP.

Overall PCAs are cyber assets most likely to be typical information technology assets like workstations, servers, printers, scanners, and other peripherals that support the work of operators and staff in the Control Center, data center, or security operations center environment. Based on type and configurations, PCAs could have the same risk profile of BES Cyber Assets associated with a high or medium BES Cyber System. Compounding the risk is that these systems may reside on the same network segments as a BES Cyber System while not being part of the BES Cyber System. Due to the potential interconnectedness of the PCA with the BES Cyber System, a compromise or misuse of the PCA could pivot to the BES Cyber System. The potential risk can be mitigated in part by technical controls, some of which are addressed in the CIP Reliability Standards and others which can be addressed in policies and procedures. For example, implementing access control lists, intrusion prevention systems, and malicious software prevention tools can be used to limit the risk posed by PCAs possibly impacting interconnected BES Cyber Systems.

Recommended Actions to Address the Risks

As a best practice, NERC staff recommends that entities evaluate each PCA type on a case-by-case basis to identify any specific risks associated with supply chain risk management and to determine whether supply chain risk management procurement processes are needed to mitigate risks to associated BES Cyber Systems. NERC staff will work with the CIPC Supply Chain Working Group to develop a guideline to assist entities in evaluating their PCAs to determine what, if any, additional supply chain protections are needed. NERC staff will also work with the CIPC Supply Chain Working Group to determine whether additional data should be collected on PCAs, as an extension of the Section 1600 data request to be prepared on low impact BES Cyber Assets.

Entities should seek assurance that hardware or software components for PCAs are authentic and have not been modified prior to provisioning the PCA and when deploying required operational or security updates. Approved configuration management and change management processes should be followed for PCAs. A best practice would be to also include PCAs in a registered entity's baselining program to track and monitor the state of PCAs within their critical infrastructure networks.

Since PCAs are often the same cyber asset type as many common BES Cyber Assets, they may be subject to "common mode vulnerabilities" and represent an attack vector to BES Cyber Systems contained within the same ESP as the PCA. A comprehensive CIP-013-1 Requirement R1 supply chain cyber security risk management plan could be effective to support mitigation of PCA cyber assets obtained under the same supply chain risk management procurement plan as BES Cyber Systems associated with high and medium impact BES Cyber Systems. The specific processes should be made on a case-by-case basis after evaluating the potential risks associated with the supply chain for that device.

NERC staff does not recommend revising the Supply Chain Standards at this time to include PCAs. While PCAs are on the same network as BES Cyber Systems, other controls deployed on the BES Cyber Systems under the CIP-007 and CIP-010 standards would protect the actual assets that could have a 15-minute impact if rendered unavailable, degraded, or misused. Since there is a wide range of assets that fall under the category of PCA, the case-by-case approach described above would provide a flexible and cost effective approach to addressing supply chain risks associated with specific PCAs while avoiding unnecessary regulatory burden.

Chapter 6: Conclusion

Compromise of certain cyber assets in the supply chain could pose a threat to BES reliability. The Supply Chain Standards require responsible entities that possess high and medium impact BES Cyber Systems develop processes to ensure that supply chain risks are being managed through the procurement process. The Supply Chain Standards will be applied to the higher-risk systems that have the greatest impact to the grid.

NERC staff recommends that the Supply Chain Standards be modified to include certain assets associated with high and medium impact BES Cyber Systems in light of the risks that may be posed by compromise of such devices in the supply chain. In light of the risks posed by compromise of such devices, and to address FERC's Order No. 850 directive, NERC staff recommends revising the Supply Chain Standards to address EACMSs. Specifically, NERC staff recommends revising the standard to include EACMSs that provide electronic access control (excluding monitoring and logging). NERC staff also recommends revising the Supply Chain Standards to include PACSs that provide physical access control (excluding alarming and logging) to high and medium impact BES Cyber Systems. In the interim, NERC staff expects that entities will apply supply chain security practices to EACMSs and PACSs to help mitigate supply chain risks associated with these devices.

At this time, NERC staff does not recommend that the Supply Chain Standards be modified to include all low impact BES Cyber Systems. As a best practice, NERC staff expects entities that have medium or high impact BES Cyber Systems will voluntarily apply CIP-013-1 Requirement R1 supply chain risk management plans to low impact BES Cyber Systems to ensure risks are identified and assessed without regard for the ultimate destination of such common cyber assets. Additional consideration may need to be given to processes used by vendors and entities to mitigate supply chain risk to lower impact systems. Risks of common-mode vulnerabilities, as described in Chapter 4, can be mitigated if supply chain security practices are applied uniformly across cyber asset types and BES Cyber System impact levels. Further study is needed, however, to determine whether there is any reliability benefit to extending the Supply Chain Standards to low impact BES Cyber Systems.

NERC staff expects entities that own only low impact BES Cyber Systems will develop supply chain risk management programs tailored to their unique risk profiles and priorities. The APPA/NRECA white paper provides considerations for smaller entities in developing such programs. NERC staff will work with the CIPC Supply Chain Working Group to develop a guideline to assist entities in voluntarily applying supply chain risk management plans to low impact BES Cyber Systems.

Due to the wide variation in risks associated with PCAs and mitigating controls already in place, NERC staff does not recommend that the Supply Chain Standards be modified to further address PCAs. NERC staff does, however, recommend that entities evaluate the risks on a case-by-case basis and adopt supply chain controls as appropriate to address those risks. NERC staff will work with the CIPC Supply Chain Working Group to develop a guideline to assist entities in evaluating their PCAs to determine what, if any, additional supply chain protections are needed. NERC staff will also work with the CIPC Supply Chain Working Group to determine whether additional data should be collected on PCAs, as an extension of the Section 1600 data request to be prepared on low impact BES Cyber Assets.

Applying Industry Practices and Guidelines

Chapter 1 identified several noteworthy supply chain risk management techniques that are not required by the CIP Reliability Standards. While these standards address many fundamental elements of effective processes to manage the risk of a supply chain, the following noteworthy approaches, if applied correctly, can reduce residual supply chain risks:

- **Independent Assessment or Third-Party Accreditation Processes:** Entities should verify that standardized processes and measures were achieved to mitigate supplier risks.

- **Secure Hardware Delivery:** Entities should take steps to ensure that hardware and software are protected during physical transport.
- **Threat-Informed Procurement Language:** Entities should tailor their security specifications to the specific risk of their environment.
- **Unsupported or Open-Sourced Technology Component Processes:** Entities should employ processes to mitigate residual risks for unsupported systems and for open source technology.
- **Using Supply Chain Controls to Mitigate Common-Mode Vulnerabilities:** Entities should voluntarily apply similar techniques to manage supply chain risks at lower impact levels.

NERC staff recommends entities include these practices in developing their supply chain risk management programs.

Going Forward

NERC will work through its existing processes with stakeholders to review NERC staff's recommendations in this report and determine appropriate follow up actions.

The following additional work should be undertaken to evaluate the recommendations included in this report:

- **Section 1600 Data Request:** NERC staff, working with the CIPC Supply Chain Working Group, will develop a Request for Information or Data under Section 1600 of the NERC Rules of Procedure in an expedited manner. The results of this request will inform whether low impact BES Cyber Systems with External Routable Connectivity should be included within the scope of CIP-013.
- **Security Guidelines:** NERC staff, working with the CIPC Supply Chain Working Group, will develop security guidelines to assist entities in managing supply chain risks for EACMSs, PACSs, PCAs and low impact BES Cyber Systems.
- **Practice Guides:** The ERO will develop CMEP practice guides to create clear expectations on the types of questions registered entities may expect regarding their low impact BES Cyber Assets and the supply chain risk management activities afforded to those assets.
- **Industry Surveys and Questionnaires to Help Identify and Assess Industry Practices**: Voluntary efforts to obtain risk data can be used to obtain information about the installed base of systems used on the BES, the procurement language in contracts negotiated with key vendors, and data describing which CIP applicable systems have benefited from procurement language stemming from the Supply Chain Standards. To encourage full and frank industry participation, NERC Staff recommends that these surveys be completed independently of any mandatory compliance monitoring or enforcement process.
- **Targeted Outreach to Vendors that Support the Reliability of the BES:** 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 customers' responsibility to meet the rigor required by the CIP Reliability Standards. It is encouraged that industry work with their vendor points of contacts to ensure that technical and contractual considerations are addressing the 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. The CIPC is working to develop a document for vendors about the CIP Reliability Standards. Further consideration should 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.

- **Third Party Accreditation/Certification Processes**: Process(es) for third party accreditation or certification should be developed and submitted to NERC for evaluation. NERC will work with stakeholders to develop an accreditation model for identifying vendors with strong supply chain risk management practices. Such identification would not only help entities comply with the proposed Reliability Standards but also increase the level of confidence that vendors providing BES-related products and services are effectively implementing supply chain cyber security controls and measures. Such process(es) should be implemented within 12 months of the effective date of Reliability Standard CIP-013-1.
- **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 BES 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 systems and implementation of greenfield systems.

Future Considerations

In developing this report, NERC has identified several issues that, while outside the scope of this report, should be considered as part of future evaluations of supply chain risks and the effectiveness of the Supply Chain Standards.

As technologies and attacks have advanced and become more complex, entities are expressing interest in partnering with outside and government security services. These includes services like NERC's Cyber Security Risk Information Sharing Program (CRISP), Cybersecurity for the Operational Technology Environment, and those of external vendors and internal monitoring centers. It may prove difficult to understand and manage any supply chain risks for these systems. However, these providers have visibility into emerging threats and trends that comes through their extensive collections of information. Analysis of this information can then be shared more broadly, improving the overall cyber security posture of the customers and reliability of the BES through early detection of compromise.

Under the current body of CIP Reliability Standards, using these types of security services (that may also include electronic access or monitoring) may bring all Cyber Assets involved into scope as an EACMS. This may discourage or even preclude entities from using these services based on the associated BES Cyber System level requirements of an EACMS. These limitations affect patching, baselines, and other requirements as outlined in the CIP Reliability Standards, and may also be impacted by the Supply Chain Standards. There is great value in correlating security events seen across those networks that could be expanded to include an entity's other non-BES Cyber Assets. This activity could be precluded or discouraged through the administration of the current CIP Reliability Standards.

Appendix A: Summary of Actions Taken to Support the NERC Board Resolutions on Supply Chain

Support Effective and Efficient Implementation

The Board requested NERC to commence preparations for implementation of the Supply Chain Standards by using similar methods during the CIP V5 transition and regularly report to the Board on those activities.

To support this action, NERC engaged in several activities. NERC created a Supply Chain Risk Mitigation Program webpage to provide a single source for resources. The CIPC has established an advisory task force to provide input on activities to support standard implementation (e.g., webinars, workshops, and technical conferences) in coordination with NERC and the Regional Entities. Efforts are also underway to document existing risks and develop security guidelines for use by industry in managing known supply chain risks.

NERC and the Regional Entities hosted several small group advisory sessions with registered entities and NERC standards developers to discuss the preparation for and implementation of the Supply Chain Standards. Each session consisted of closed one-on-one discussions between a registered entity's supply chain security experts and ERO Enterprise staff about concerns pertinent to the entity's implementation of the proposed Supply Chain Standards. These sessions resulted in the development of a Frequently Asked Questions document.[44] The document addresses many of the questions and concerns voiced during those sessions.

In addition, NERC and the Regional Entities presented on the Supply Chain Standards and the security concerns regarding supply chain during regional workshops and outreach engagements. These presentations highlighted some of the costs regarding cyber attacks, risks identified in the EPRI Interim Report, and well-known public supply chain compromises. NERC also presented similar presentations to industry and other independent industry groups.

Going forward, NERC is considering additional small group advisory sessions and providing targeted outreach to entities and stakeholders.

In addition to actions taken to support the Board Resolutions, industry is also using existing NERC structures to improve reliability, security, and compliance. For instance, several prequalified organizations have already submitted compliance implementation guidance to support effective implementation of the Supply Chain Standards.

Cybersecurity Supply Chain Risk Study

The Board requested NERC to study the nature and complexity of cyber security supply chain risks, including those associated with low impact assets not currently subject to the Supply Chain Standards, and develop recommendations for follow-up actions that will best address identified risks. The interim report would be due 12 months after adoption of the resolutions and a follow-up final report would be due 18 months after adoption.

The following activities have occurred to support this action and are listed as follows:

- **Interim Report**
  - NERC contracted the Electric Power Research Institute to prepare an interim report on supply chain risks. The report focuses on the following areas:
    - An assessment of product/manufacturer types used on the BES
    - An analysis and applicability to BES Cyber Assets

[44] Frequently Asked Questions, Supply Chain – Small Group Advisory Sessions: https://www.nerc.com/pa/comp/SupplyChainRiskMitigationProgramDL/SGAS%20FAQ%2006252018.pdf. (June 28, 2018).

  - An analysis of best practices and standards in other industries to mitigate supply chain risks
  - An analysis of generalized vendor practices and approaches used to mitigate supply chain risks
- NERC staff presented the interim report at the August 2018 Board meeting and posted the report on the Supply Chain Risk Mitigation Program webpage.

- **Final Report**

  This report, *Supply Chain Risks: Final Report and Recommended Actions*, was presented in draft to the Board in February 2019 and will be presented for acceptance to the Board in May 2019.

Communicate Supply Chain Risks to Industry

The Board requested NERC to communicate supply chain risk developments and risks to industry in connection with this report.

The following activities have occurred to support this action:

- NERC and E-ISAC have used NERC Alerts to communicate supply chain risks to industry.
- E-ISAC included a supply chain risk topic in NERC's Grid Security Exercise (GridEx IV).
- NERC and Regional Entities have included supply chain topics at workshops in 2018.
- CIPC is in the process of developing supply chain security guidelines.

Forum White Papers

The Board requested that the Forums (NATF and the NAGF) develop (and distribute, as permissible) white papers to address best and leading practices in supply chain management as described in the resolution.

To support this action, the Forums have developed white papers, which are posted on the Supply Chain Risk Mitigation Program webpage.

Association White Papers

The Board requested that the Associations (NRECA and APPA) develop (and distribute, as permissible) white papers to address best and leading practices in supply chain management, focusing on smaller entities that are not members of the Forums, for the membership of the Associations.

To support this action, the Associations jointly developed a white paper, which is posted on the Supply Chain Risk Mitigation Program webpage.

Evaluate Supply Chain Standard Effectiveness

The Board requested that NERC, collaborating with NERC technical committees and other experts, develop a plan to evaluate the effectiveness of the Supply Chain Standards, as described in the resolution, and report to the Board.

The plan to evaluate the effectiveness of the Supply Chain Standards will be developed by NERC staff in 2019, with assistance of the CIPC advisory group and Regional Entities.

Additional Information

NERC's Supply Chain Risk Mitigation Program webpage[45] provides more information on these and other ongoing efforts to support the implementation of the Supply Chain Standards and address ongoing supply chain considerations.

[45] NERC, Supply Chain Risk Mitigation Program: https://www.nerc.com/pa/comp/Pages/Supply-Chain-Risk-Mitigation-Program.aspx.

Appendix B: CIPC Supply Chain Working Group Members

NERC wishes to take this opportunity thanks the following members of the CIPC Supply Chain Working Group and their organizations for their valuable contribution to this report.

Table B.1: CIPC Supply Chain Working Group

Member Name	Company
Amelia Anderson	CenterPoint Energy
Andy Bochman	IBM
Bob Lockhart	Utilities Technology Council
Brenda Davis	CPS Energy
Brian Bouyea	New York ISO
Brian Millard	Tennessee Valley Authority
Brian Tooley	Vectren
Celia Sieg	New York ISO
Chip Wenz	AES Corporation
Christopher Keane	Duke Energy
Christopher Plensdorf	DTE Energy
Christopher Walcutt	Direct Defense
Dalini Khemlani	Amazon Web Services
Darrell Klimitchek	South Texas Electric Cooperative
Darren Hulskotter	CPS Energy
David Godfrey	Garland Power & Light Company
David Jacoby	Boston Strategies International
David Sampson	DTE Energy
Donald Hargrove	Oklahoma Gas and Electric Co.
James Brown	California ISO
James Howard	Lakeland Electric
Jeffrey Kimmelman	Network and Security Technologies
Jerrod Montoya	Open Access Technology International
Jim McNierney	New York ISO

Table B.1: CIPC Supply Chain Working Group	
Member Name	**Company**
John Hochevar	American Transmission Company
Jose Flores	North American Transmission Forum
Joseph Smith	Public Service Enterprise Group
Kaitlin Brennan	Edison Electric Institute
Kara White	NRG
Karl Perman	EnergySec
Keith St. Amand	Midwest ISO
Ken Keels	North American Transmission Forum
Kevin Weber	Entergy
Lee Maurer	Oncor Electric Delivery
Marc Child	Great River Energy
Marina Rohnow	San Diego Gas and Electric
Mark Henry	Texas Reliability Entity
Matt Anglin	New York ISO
Michael Aukerman	Denton Municipal Electric
Michael Meason	Western Farmers Electric Cooperative
Mike Mertz	PNM Resources
Michele Wright	FoxGuard Solutions
Michelle Coon	Open Access Technology International
Mike Kraft	Basin Electric Power Cooperative
Mike Prescher	Black and Veatch
Monika Montez	California ISO
Nathan Shults	Kiewit Engineering and Design
Patricia Ireland	DTE Electric
Patricia Meara	Network and Security Technologies
Peter Nelson	Network and Security Technologies
Pierre Janse van Rensburg	ENMAX Power Corporation

Table B.1: CIPC Supply Chain Working Group	
Member Name	**Company**
Reed Thompson	Public Service Enterprise Group
Robert Koziy	Open Systems International
Ryan Carlson	Proven Compliance Solutions
Sarah Stevens	North American Transmission Forum
Scott Webb	Network and Security Technologies
Sharla Artz	Utilities Technology Council
Sheranee Nedd	Public Service Enterprise Group
Steen Fjalstad	Midwest Reliability Organization
Steve Brain	Dominion Energy
Steven Briggs	Tennessee Valley Authority
Tony Eddleman	Nebraska Public Power District

167 FERC ¶ 61,249
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM19-10-000]

Transmission Planning Reliability Standard TPL-001-5

(June 20, 2019)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to approve Reliability Standard TPL-001-5 (Transmission System Planning Performance Requirements). The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, submitted the proposed Reliability Standard for Commission approval to address: (1) reliability issues concerning the study of single points of failure of protection systems; and (2) Commission directives regarding planned maintenance outages and stability analysis for spare equipment strategy. In addition, the Commission proposes to direct NERC to modify the Reliability Standards to require corrective action plans for protection system single points of failure in combination with a three-phase fault if planning studies indicate potential cascading.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER].**

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

Eugene Blick (Technical Information)
Office of Electric Reliability
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(301) 665-1759
eugene.blick@ferc.gov

Bob Stroh (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8473
robert.stroh@ferc.gov

SUPPLEMENTARY INFORMATION:

167 FERC ¶ 61,249
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning Reliability Standard TPL-001-5 Docket No. RM19-10-000

NOTICE OF PROPOSED RULEMAKING

(June 20, 2019)

1. Pursuant to section 215(d)(2) of the Federal Power Act (FPA), the Commission proposes to approve Reliability Standard TPL-001-5 (Transmission System Planning Performance Requirements).[1] The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted proposed Reliability Standard TPL-001-5 for Commission approval to address: reliability issues concerning the study of single points of failure of protection systems discussed in Order No. 754; and directives from Order No. 786 regarding planned maintenance outages and stability analysis for spare equipment strategy.[2]

2. Proposed Reliability Standard TPL-001-5 is one of two transmission planning Reliability Standards containing requirements for planning authorities and transmission planners to develop studies of their portions of the bulk electric system. Proposed Reliability Standard TPL-001-5 establishes transmission system planning performance

[1] 16 U.S.C. 824o(d)(2) (2012).

[2] *Interpretation of Transmission Planning Reliability Standard*, Order No. 754, 136 FERC ¶ 61,186, at P 19 (2011); *Transmission Planning Reliability Standards*, Order No. 786, 145 FERC ¶ 61,051, at PP 40, 89 (2013)

requirements within the planning horizon to promote a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. NERC states that the revisions in the proposed Reliability Standard are intended to enhance requirements for the study of protection system single points of failure.[3]

3. Proposed Reliability Standard TPL-001-5 requires each planning authority and transmission planner to perform an annual planning assessment of its portion of the bulk electric system considering a number of system conditions and contingencies. The proposed Reliability Standard employs a risk-based approach to the study of contingencies and the types of corrective action that are required if the entity's system cannot meet the specified performance requirements.[4] For scenarios considered to be more commonplace (i.e., planning events), the planning entity must develop a corrective action plan if it determines through studies that its system would experience performance issues. For the scenarios considered to be less commonplace, but which could result in potentially severe impacts such as cascading (i.e., extreme events), the planning entity

[3] A protection system "single point of failure" refers to a non-redundant component of a protection system that, if it failed, would affect normal clearing of faults. NERC Petition at 4.

[4] NERC defines "Corrective Action Plan" as, "A list of actions and an associated timetable for implementation to remedy a specific problem." Glossary of Terms Used in NERC Reliability Standards (May 13, 2019) (NERC Glossary).

(continued…)

must conduct a comprehensive analysis to understand both the potential impacts on its system and the types of actions that could reduce or mitigate those impacts.[5]

4. Proposed Reliability Standard TPL-001-5 contains revisions to both the planning event (Category P5) and extreme events (Stability 2.a-h) - identified in Table 1 (Steady State and Stability Performance Planning Events and Steady State and Stability Performance Extreme Events) and the associated footnote 13 - to provide for more comprehensive study of the potential impacts of protection system single points of failure.[6] Planning entities would be required to take action, consistent with currently-effective Reliability Standard TPL-001-4 requirements, to address system performance issues identified as a result of these studies. Additionally, the proposed Reliability Standard addresses the two Commission directives in Order No. 786. Accordingly, pursuant to section 215(d)(2) of the FPA, the Commission proposes to approve proposed Reliability Standard TPL-001-5 because it is responsive to the Commission's directives

[5] NERC defines "Cascading" as, "The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies." NERC Glossary.

[6] Proposed Reliability Standard TPL-001-5 includes an expanded list of protection system components for single points of failure studies. The selected list of components account for: (1) those failed non-redundant components of a protection system that may impact one or more protection systems; (2) the duration that faults remain energized until delayed fault clearing; and (3) the additional system equipment removed from service following fault clearing depending on the specific failed non-redundant component of a protection system. NERC Petition at 16.

(continued…)

and improves upon the currently-effective Reliability Standard by enhancing requirements for the study of protection system single points of failure.

5. Non-redundant protection systems can also misoperate when faced with a three-phase fault. Because three-phase faults are more serious than single-phase-to-ground faults, the consequences can be more severe, including cascading. However, rather than require a corrective action plan to address such events, proposed Reliability Standard TPL-001-5 only requires an evaluation of possible actions designed to reduce the likelihood or mitigate their consequences and adverse impacts.[7] NERC has not adequately justified categorizing protection system single points of failure in combination with a three-phase fault as an "extreme event" that only requires study, but not a corrective action plan, when there is the potential for cascading. We are not persuaded that such events do not necessitate corrective action plans because of their alleged rarity, particularly because their potential impacts may result in cascading. Thus, pursuant to section 215(d)(5) of the FPA, we also propose to direct that NERC develop modifications to the Reliability Standards to require corrective action plans for protection system single points of failure in combination with three-phase faults if planning studies indicate potential cascading.[8]

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[7] NERC, Informational Filing, Docket No. RM10-06-000, at 10 (filed March 15, 2012) (2012 Informational Filing). A three-phase fault can originate as a single-line-to-ground (SLG) fault as "it is not uncommon for a SLG fault to evolve to a multi-phase fault." *Id.*

[8] 16 U.S.C. 824o(d)(5).

I. Background

A. Section 215 and Mandatory Reliability Standards

6. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[9] Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[10] and subsequently certified NERC.[11]

B. Order No. 754

7. In Order No. 754, which approved an interpretation of Reliability Standard TPL-002-0, Requirement R1.3.10, the Commission determined that "there may be a system protection issue that merits further exploration by technical experts" and that there is "an issue concerning the study of the non-operation of non-redundant primary protection systems; e.g., the study of a single point of failure on protection systems."[12]

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

[10] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006).

[11] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[12] Order No. 754, 136 FERC ¶ 61,186 at P 19.

(continued…)

To address this concern, the Commission directed "Commission staff to meet with NERC and its appropriate subject matter experts to explore the reliability concern, including where it can best be addressed, and identify any additional actions necessary to address the matter."[13] The Commission also directed NERC "to make an informational filing . . . 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."[14]

8. In October 2011, Commission staff hosted a technical conference on single points of failure, which resulted in four consensus points and the following problem statement: "The group perceives a reliability concern regarding the comprehensive assessment of potential protection system failures by registered entities. The group agrees on the need to study if a [reliability] gap exists regarding the study and resolution of a single point of failure on protection systems."[15] One outcome of the 2011 technical conference, as described in the 2012 Informational Filing, was that NERC would issue a data request to aid in assessing whether single points of failure in protection systems pose a reliability concern. To that end, the NERC Board of Trustees subsequently approved a request for

[13] *Id.* P 20.

[14] *Id*.

[15] NERC, Order No. 754 Single Point of Failure Technical Meeting Notes at 8 (October 24-25, 2011).

(continued…)

data under the NERC Rules of Procedure.[16] Over the next two years, NERC collected data from transmission planners. Using the collected data, two subcommittees of the NERC Planning Committee, the System Protection and Control Subcommittee (SPCS) and the System Analysis and Modeling Subcommittee (SAMS), conducted an assessment of protection system single points of failure. The study examined in detail the protection systems related to nearly 4,000 buses. The findings were presented in a September 2015 report that concluded that single points of failure on protection systems posed a reliability risk that warranted further action.[17] The SPCS/SAMS Report recommended, after considering a variety of alternatives, that NERC modify Reliability Standard TPL-001-4 to best align with the Order No. 754 directives and maximize reliability of protection system performance. In particular, the SPCS/SAMS Report recommended that three-phase faults involving protection system failures be assessed as an extreme event in Reliability Standard TPL-001-4, as follows:

> Additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure. This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in TPL-001-4 Part 4.5. From TPL-001-4, 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 and adverse impacts of the event(s) shall be conducted.[18]

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[16] 2012 NERC Informational Filing at 7 (stating that the data request "is based on an approach that utilizes . . . a three-phase (3Ø) fault and assesses simulated system performance against performance measures").

[17] NERC, Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request at 11 (September 2015) (SPCS/SAMS Report).

[18] *Id.*

C. Order No. 786

9. In Order No. 786, the Commission approved the currently-effective version of the transmission system planning standard, Reliability Standard TPL-001-4. In that Order, the Commission also issued several directives to NERC, including two relating to future standard modifications that are addressed in proposed Reliability Standard TPL-001-5. First, the Commission expressed concern that the six-month outage duration threshold in Reliability Standard TPL-001-4, Requirement R1 could exclude planned maintenance outages of significant facilities from future planning assessments.[19] The Commission determined 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, and that 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. The Commission further determined that 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 nonconsequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding. The Commission directed NERC to modify the Reliability Standards to address this concern.

[19] Order No. 786, 145 FERC ¶ 61,051 at PP 40-45.

10. Second, while stating that NERC had met the Commission's Order No. 693 directive to include a spare equipment strategy for steady state analysis in Reliability Standard TPL-001-4, the Commission determined that a spare equipment strategy for stability analysis was not addressed in the standard. The Commission stated 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. Rather than direct a change at that time, however, the Commission directed NERC to consider the issue during the next review cycle of Reliability Standard TPL-001-4.[20]

D. NERC Petition and Proposed Reliability Standard TPL-001-5

11. On December 7, 2018, NERC submitted proposed Reliability Standard TPL-001-5 for Commission approval.[21] NERC maintains that the proposed Reliability Standard addresses potential system contingencies including the protection system single point of failure issue and Order No. 786 directives. With regard to protection system single points of failure, NERC indicates that Table 1 of the proposed Reliability Standard describes system performance requirements for a range of potential system contingencies required to be evaluated by the planner. Table 1 includes three parts: (1) Steady State & Stability

[20] *Id.* PP 88-89.

[21] Proposed Reliability Standard TPL-001-5 is not attached to this notice of proposed rulemaking (NOPR). The proposed Reliability Standard is available on the Commission's eLibrary document retrieval system in Docket No. RM19-10-000 and on the NERC website, www.nerc.com.

Performance Planning Events, (2) Steady State & Stability Performance Extreme Events, and (3) Steady State & Stability Performance Footnotes. Table 1 describes system performance requirements for a range of potential system contingencies required to be evaluated by the planner. The table categorizes the events as either "planning events" or "extreme events." The table lists seven contingency planning events (P1 through P7) that require steady-state and stability analysis as well as five extreme event contingencies: three for steady-state and two for stability. NERC asserts that proposed Reliability Standard TPL-001-5 also includes certain modifications to better ensure that planning entities are performing a more complete analysis of potential protection system single points of failure on their systems and taking appropriate action to address these concerns. NERC explains that the proposed Reliability Standard contains revisions to both the Table 1 planning event (Category P5) and extreme events (Stability 2.a-h) and the associated footnote 13 to provide for more comprehensive study of the potential impacts of protection system single points of failure.

12. NERC states that if the study of a protection system single point of failure for a single-line-to-ground fault (i.e., Category P5 event) results in cascading, a corrective action plan is required.[22] NERC considers this a relatively commonplace scenario, and it

[22] Proposed TPL-001-5 Reliability Standard, Table 1 (Steady State and Stability Performance Planning Events), Category P5 requires the study of a single-line-to-ground faulted element (e.g., generator, transmission circuit or transformer) along with a failure to operate of a non-redundant component of the protection system (i.e., a single point of failure) protecting the faulted element.

explains that an entity would be required to develop a corrective action plan if it determines that its system would be unable to meet the performance requirements of Table 1 for the Category P5 event.

13. In contrast, NERC proposes revisions to Table 1 to include the study of a protection system single point of failure in combination with a three-phase fault as an extreme event, which does not require a corrective action plan. NERC avers in its petition that the three-phase fault scenario is much rarer (compared to the single-line-to-ground fault). According to NERC, like the other extreme events in the proposed Reliability Standard, this scenario, while rare, could result in more significant impacts to an entity's system.[23] Under this approach, NERC asserts that, if an entity determines that its system will experience cascading as a result of a three-phase fault scenario, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event will be conducted but a corrective action plan is not required.

14. Based on a historical analysis of NERC data on protection system misoperations, NERC asserts that the expected likelihood of a three-phase fault event occurring and resulting in the most severe impacts would be small. NERC states that it reviewed over 12,000 protection system misoperations in its Misoperation Information Data Analysis

[23] *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218, at P 1826, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007) (describing extreme events as "events resulting in loss of two or more elements or Cascading" that do not require a corrective action plan rather than assigning a quantitative probability to the event).

(continued…)

System (MIDAS) database reported since 2011, of which only 28 involved three-phase faults. Of those, NERC states that 10 involved breakers that failed to operate, and the remaining 18 involved breakers that were slow to operate.[24] NERC explains that a failure to operate potentially indicates instances of a protection system single point of failure. While the potential for severe impacts from such events remains, NERC states that none of the 10 failure to trip scenarios reported since 2011 resulted in events that reached the threshold for reporting under Reliability Standard EOP-004 (Event Reporting).[25] With regard to the Order No. 786 directives, NERC states that proposed Reliability Standard TPL-001-5 provides for a more complete consideration of factors for selecting which known outages will be included in near-term transmission planning horizon studies.

[24] NERC Petition at 26, n.55 ("The ERO began to collect misoperations data in a common format beginning in 2011. Applicable entities are currently required to report information on Protection System misoperations to NERC pursuant to a request for data or information under Section 1600 of the NERC Rules of Procedure approved by the NERC Board of Trustees on August 14, 2014. Previously, the PRC-004 standard contained requirements for misoperation reporting."); *see also North American Electric Reliability Corp*., 151 FERC ¶ 61,129, at P 6 (2015) ("PRC-004-3, and the parallel Section 1600 Data Request provides means to accomplish this systematic analysis and correction").

[25] Reliability Standard EOP-004-3 (Event Reporting), Attachment 1: Reportable Events, contains a list of various thresholds for reporting certain events to NERC. Examples of reporting thresholds include: loss of firm load for 15 minutes or more if 300 MW or greater for entities with a previous year's demand of at least 3,000 MW, or 200 MW or greater for all other entities, and total generation loss within one minute 2,000 MW or greater for entities in the Eastern or Western Interconnection, or 1,000 MW for entities in the ERCOT or Quebec Interconnection.

II. Discussion

15. Pursuant to section 215(d)(2) of the FPA, the Commission proposes to approve proposed Reliability Standard TPL-001-5 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The proposed Reliability Standard will improve Bulk-Power System reliability by requiring enhanced transmission system planning with regard to the study of protection system single points of failure in combination with a single-line-to-ground fault, as discussed in Order No. 754. The Commission also proposes to approve the associated violation risk factors, violation severity levels and implementation plan.

16. With respect to the Order No. 786 directives, regarding planned maintenance outages and stability analysis for spare equipment strategy, the Commission proposes to determine that the revisions satisfy the directives. First, proposed Reliability Standard TPL-001-5 provides for a more complete consideration of factors for selecting which known outages will be included in near-term transmission planning horizon studies. In particular, the modifications reflected in proposed Reliability Standard TPL-001-5 address the Commission's concern that the exclusion of known outages of less than six months in currently-effective Reliability Standard TPL-001-4 could result in outages of significant facilities not being studied. Second, the proposed Reliability Standard modifies requirements for stability analysis to require an entity to assess the impact of the possible unavailability of long lead time equipment, consistent with the entity's spare equipment strategy.

17. In addition, the Commission, pursuant to section 215(d)(5) of the FPA, proposes to direct that NERC develop modifications to the Reliability Standards because certain protection system single points of failure may not be fully addressed even with the implementation of proposed Reliability Standard TPL-001-5. As discussed below, the Commission is concerned that the proposed Reliability Standard does not require responsible entities to develop corrective action plans to address protection system single points of failure in combination with a three-phase fault if planning studies indicate potential cascading. Accordingly, the Commission proposes to direct that NERC develop modifications to the Reliability Standards to require corrective action plans for protection system single points of failure in combination with three-phase faults if planning studies indicate potential cascading.

A. The Record Indicates There is a Reliability Gap for a Protection System Single Point of Failure in Combination with a Three-Phase Fault

18. While protection system single points of failure in combination with a three-phase fault must be studied under the proposed Reliability Standard to determine the impact of failure, the Commission believes that the record may not support NERC's contention that corrective action plans should not be required even when studies of the event indicate the potential for cascading. Specifically, NERC asserts that protection system single points of failure in combination with a three-phase fault is an extreme event that does not require a corrective action plan, even in cases where the study results indicate potential cascading. NERC claims that protection system single points of failure in combination with a three-phase fault are rare and, "[l]ike all of the 'extreme events' scenarios in this

[TPL-001 Standard risk-based] framework, the impacts of a protection system single point of failure in combination with a three phase fault could be severe in some cases, but are very unlikely."[26] Based on the present record, it is unclear whether such contingencies are as rare as NERC maintains.

19. A 2009 NERC Industry Advisory reported three system disturbances that occurred during a five-year period that were initiated by a protection system single point of failure in combination with a single-line-to-ground fault.[27] According to the Industry Advisory and supporting documentation, all three events evolved into either a multi-phase fault or a three-phase fault with cascading.[28] Moreover, in the 2012 Informational Filing, NERC reported that it is not uncommon for a single-line-to-ground fault to evolve into a multi-phase fault, and NERC stated that studies solely on single-line-to-ground faults may understate the reliability risk of single points of failure of protection systems.[29] As mentioned below, the NERC standard drafting team pointed to the likelihood of a single-line-to-ground fault evolving into a multi-phase fault when responding to stakeholder comments that a single-line-to-ground fault was a rare event.

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[26] NERC Petition at 26.

[27] NERC, Industry Advisory: Protection System Single Point of Failure (March 30, 2009) (2009 NERC Industry Advisory).

[28] *Id.* at 2 ("Three system disturbances were caused by failure of a single component (lockout or auxiliary relay) of a protection system.").

[29] 2012 NERC Informational Filing at 3, 10 ("identif[ying] five events between 2004 and 2010 in which a single point of failure on a protection system caused, in whole or in part, an event on the Bulk-Power System…").

(continued…)

20. NERC indicates that it reviewed over 12,000 protection system misoperations and determined that only 28 involved three-phase faults from 2011 through 2018. However that averages to approximately one three-phase fault event every three months. NERC, moreover, indicates that ten of those 28 misoperations involved breakers that failed to operate that could reasonably be assumed to be representative of protection system single points of failure, which averages to about one event every 8 months.[30] Although we recognize that three-phase faults constitute a relatively small subset of all protection system operations, under the following measure of one protection system single point of failure every 8 months, the occurrence of three-phase faults with misoperations could reasonably be viewed as regular occurrences. Thus, based on the information currently before us, we are not persuaded by NERC's analysis that three-phase faults are rare events that should be categorized with other extreme events in proposed Reliability Standard TPL-001-5 and should be studied but not have corrective action plans.

21. The record of development for proposed Reliability Standard TPL-001-5 also supports our concerns with the absence of a corrective action plan requirement. The development record evidences a standard drafting team repeatedly expressing concerns regarding the reliability risks of three-phase faults involving protection system single points of failure. Indeed, the standard drafting team evaluated and initially adopted more

[30] NERC Petition at 26-27. NERC stated that none of the ten failure to trip scenarios reached the threshold for reporting under Reliability Standard EOP-004. Although NERC did not offer further explanation, system conditions such as off-peak load conditions could have contributed to whether Reliability Standard EOP-004 thresholds were met.

robust options to mitigate protection system single points of failure in combination with three-phase faults if studies indicated cascading, including requiring a corrective action plan or some variation of a corrective action plan.

22. In the first draft of proposed Reliability Standard TPL-001-5, the standard drafting team included a draft requirement (Requirement R4.6) that would have addressed protection system single points of failure in combination with a three-phase fault, including a specific requirement for the development of a corrective action plan.[31] After reviewing the unofficial comments on the proposal, the standard drafting team provided the following response:

> The [standard drafting team (SDT)] recognized that the industry comments . . . were particularly negative. The SDT would like to address the most common comment received: requiring Corrective Action Plans as part of Requirement R4.6 goes beyond the scope of the SAR, was not part of the recommendations from the SPCS/SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request", and/or is not justifiable given the low likelihood of occurrence. . . . While it is clear that a [single point of failure (SPF)] for a Protection System component may lead to significantly longer Delayed Clearing and notably worse system response than typically analyzed breaker failure conditions, the industry has indicated that the probability of simultaneous SPF occurrence with a bolted three-phase fault is low. Therefore the SDT has restored the assessment of SPF for a Protection System component with a three-phase fault to language consistent with TPL-001-4 Requirement 4.5.[32]

[31] NERC Petition, Ex. G (Summary of Development and Complete Record of Development) at page 372-373 of pdf ("If the analysis concludes there is Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h, a Corrective Action Plan shall be developed.").

[32] *Id.* at page 810 of pdf.

While the standard drafting team agreed to remove the corrective action plan provision in response to the stakeholder comments, the following language from the standard drafting team's response stressed the reliability concerns posed by protection system single points of failure in combination with a three-phase fault, and suggested that the related risks are "underappreciated":

> The SPF for a Protection System component is an important topic that, the SDT believes, may involve risks that are underappreciated. The SDT considered using Corrective Action Plan changes in proposed Requirement 4.6 or a new Table 1 Planning Events Category P8 to emphasize the importance of this issue, but given the industry comments and lack of a FERC directive did not "raise the bar" at this time. The SDT would like to document an important considerations (sic) it considered, that the fault conditions and system performance requirement, referred to as Performance Measure, of the Order 754 data request were very similar to those of Extreme Events of TPL-001-4 Table 1, namely three-phase fault application and conditions that can indicate Cascading. The primary conclusive finding of the SPCS/SAMS report was: "analysis of the data demonstrates the existence of a reliability risk associated with single points of failure in protection systems that warrants further action." Further, the SPCS/SAMS report concluded that: "additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure."[33]

The standard drafting team's above response acknowledged the importance of a corrective action plan and noted conclusive findings of the SPCS/SAMS report that the reliability risk associated with protection system single points of failure warrants further action. The standard drafting team, nonetheless, indicated that "lacking a FERC directive" it would remove the corrective action plan provision.

[33] *Id.*

23. The standard drafting team then developed a second draft of proposed Reliability Standard TPL-001-5. The second draft did not require a corrective action plan by name. Rather, the standard drafting team developed and submitted for ballot a new provision requiring that, when system studies show that a protection system single points of failure in combination with a three-phase fault results in system cascading, the entity must take specific actions, namely "listing system deficiencies, the associated actions needed to prevent the system from Cascading and the associated timetable for implementation."[34] Further, the proposed provision would require follow-up in annual planning assessments for "continued validity and implementation status."

24. The standard drafting team developed a technical rationale document that accompanied the second draft of the proposed Reliability Standard.[35] In the draft technical rationale document, the standard drafting team explained the technical basis for draft Requirement R4.2.2:

> Given the risk to BES reliability, additional emphasis in planning studies should be placed on assessment of three-phase faults involving Protection System SPF. This concern (the study of Protection System SPF) is appropriately addressed as an extreme event in TPL-001-4, Requirement R4, Part 4.2. While less probable than single-phase-to-ground faults, *three-phase faults typically initiate as single-phase-to-ground and often evolve into three-phase faults*, leading to Delayed Fault Clearing scenarios more severe than the Table 1 P5 event. Therefore, TPL-001-4, Requirement R4, Part 4.5, which specifies that an evaluation of possible mitigating actions

[34] *Id*. at page 824 of pdf (proposed Requirement 4.2.2).

[35] *Id.* at page 942 of pdf.

(continued…)

> be conducted if analysis concludes there is cascading caused by the occurrence of this extreme event, *is inadequate to address the risk of Protection System component SPF to the reliability of the BES*.[36]

Again, the standard drafting team expressed its concerns regarding the reliability risks associated with a protection system single point of failure in combination with a three-phase fault. The standard drafting team addressed the stakeholder comments regarding the perceived low risk of such conditions by pointing out that "[w]hile less probable than single-phase-to-ground faults, three-phase faults typically initiate as single-phase-to-ground and often evolve into three-phase faults, leading to Delayed Fault Clearing scenarios more severe than the Table 1 P5 event."[37] Further, the standard drafting team noted the inadequacy of simply conducting an "evaluation" as set forth in the relevant provision of the current Reliability Standard.[38]

25. The standard drafting team developed a third draft of the proposed Reliability Standard. This third draft removed the more robust provision (proposed Requirement R4.2.2) in favor of the currently proposed language in Requirement 4.2, which requires that "[i]f 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

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[36] *Id.* at page 950-951 of pdf (emphasis added).

[37] *Id*.

[38] The second draft of Reliability Standard TPL-001-5, was voted down by stakeholders, with stakeholders suggesting the removal of Requirement R4.2.2 again suggesting that three-phase fault followed by a protection failure is a low probability event. *Id*. at page 1327 of pdf.

consequences of the event (s) shall be conducted." Significantly, however, in the draft technical rationale document associated with the second draft of the proposed Reliability Standard, the standard drafting team stated that merely requiring that "an evaluation of possible mitigating actions be conducted if analysis concludes there is cascading caused by the occurrence of this extreme event, *is inadequate to address the risk of Protection System component SPF to the reliability of the BES*."[39]

26. The standard development history discussed above therefore supports our concern that there is a potential reliability gap with respect to the proposed Reliability Standard's treatment of protection system single points of failure in combination with a three-phase fault.[40]

B. Commission Proposal

27. The Commission, pursuant to section 215(d)(5) of the FPA, proposes to direct that NERC develop modifications to require corrective action plans for protection system single points of failure in combination with three-phase faults if planning studies indicate potential cascading. While we do not propose to prescribe how NERC should respond to the proposed directive, we discuss below certain possible alternatives.

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[39] *Id.* at page 951 of pdf (emphasis added).

[40] The standard development record indicates several stakeholder comments in support of a corrective action plan requirement for protection system single points of failure in combination with a three-phase fault that was proposed in the third draft. For example, one commenter suggested "the best way to achieve this [corrective action plan] requirement is through the creation of a P8 [new category planning event] contingency rather than extreme events." Another commenter stated it "does not believe though that the language . . . goes far enough . . . and believes a corrective action plan should be required." *Id.* at pages 2283, 2291, 2415, and 2424 of pdf.

28. NERC could address the proposed directive by modifying the current Category P5 proposal for single-line-to-ground faults (that already includes a P5 corrective action plan) to include language, such as, a footnote stating that the simulation of Delayed Fault Clearing must consider that a single-line-to-ground faulted condition may evolve to all three-phases before protection system action operates to clear the fault. Alternatively, NERC could modify the Reliability Standard to have a new Category planning event that would require a corrective action plan for the study of a protection system single point of failure in combination with a three-phase fault if the study indicates cascading.[41]

29. In addition, we recognize that during the standard drafting process for proposed Reliability Standard TPL-001-5 some stakeholders were concerned with incurring significant costs to mitigate protection system single points of failure in combination with a three-phase fault, while others stated that such actions do not usually incur significant costs.[42] While we are aware of the potential for increased cost under this proposal, we understand that there are likely cost-effective actions that could be taken to mitigate a protection system single point of failure in combination with a three-phase fault. For example, a corrective action plan to eliminate a single point of failure of protection system could add a redundant lockout relay in the control circuitry of a protection system,

[41] *See id.* at page 1506 and 1746 of pdf.

[42] *See*, *e.g.*, *id.* at page 1016 (Seattle City Light), 1019 (Arizona Public Service), 1044 (Northeast Power Coordinating Council), 1048 (Eversource Energy), 1331 and 1333 (Standard Drafting Team Response to Commenters) of pdf.

(continued…)

which would eliminate occurrence of those events reported in the 2009 NERC Industry Advisory.[43] As another option, an entity could add control center monitoring and reporting functions to a DC battery bank or to a communication system of a communication-aided protection scheme so that system operators are aware of their failure.[44] To better understand the potential for increased costs and other implementation issues, the Commission seeks comment on how many corrective action plans are expected for protection system single points of failure in combination with a three-phase fault if study results indicate cascading.

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[43] NERC Petition at 20 ("most, if not all, constituent parts of the control circuitry are generally unmonitored, may fail, and may remain undetected until periodic testing is conducted. This is particularly significant for non-redundant auxiliary relays or lockout relays within the control circuitry because they may be used for multiple functions . . . ."). In addition, the standard drafting team stated that "[i]t is emphasized that Footnote 13 does not prescribe any level of redundancy . . . . If, after proper consideration and simulation, required System performance is achieved, then there may be no impetus to make non-redundant components of a Protection System redundant. On the other hand, after proper consideration and simulation it is demonstrated that required System performance is not achieved, making non-redundant components of a Protection System redundant may be but one of many alternatives for corrective actions to obtain required System performance." *Id.*, Ex. G at page 162 of pdf.

[44] NERC Petition at 18-19 (stating that "[f]ootnote 13 provides that certain non-redundant components that are both monitored and reported at a Control Center would not need to be considered as part of planning studies. This includes the communications systems identified in footnote 13.b. The standard drafting team considered that the monitoring and reporting of a non-redundant component to a centralized location (i.e., the Control Center) would facilitate prompt identification and correction of abnormal conditions to minimize the exposure to and consequence of the failed component . . . Similar to footnote 13.b, monitoring and reporting the status of the DC supply to a centralized location [i.e., footnote 13.c] can be considered 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").

(continued…)

30. To ensure no delay and to align the effective date of the proposed directive with the current implementation plan of proposed Reliability Standard TPL-001-5, the Commission proposes to direct that NERC address the directive within one year of the effective date of a final rule.[45] The Commission seeks comments on its proposals.

III. Information Collection Statement

31. The FERC-725N information collection requirements contained in this notice of proposed rulemaking are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[46] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[47] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

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[45] NERC Petition, Exhibit B (Implementation Plan) at 2.

[46] 44 U.S.C. 3507(d) (2012).

[47] 5 CFR 1320.11 (2018).

32. The Commission bases its paperwork burden estimates on the changes in paperwork burden presented by proposed Reliability Standard TPL-001-5. The NERC Compliance Registry, as of May 10, 2019, identifies approximately 144 planning coordinators and transmission planners in the United States that are subject to mandatory compliance with this proposed Regulatory Standard. Of the 144 entities 62 of the entities are registered as both transmission planners and planning coordinators. The register indicates there are seven entities registered as planning coordinators and 137 entities registered as transmission planners.

33. Burden Estimate[48]: The estimated burden and cost for the requirements contained in this proposed rule follows:

[48] "Burden" is the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the information collection burden, refer to 5 CFR § 1320.3.

RM19-10-000 NOPR FERC-725N (Mandatory Reliability Standards: Reliability Standard TPL-001-5)					
Areas of Modification	**Number of Respondents (1)**	**Annual Number of Responses [49] per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response [50] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**
Single Point of Failure (one-time)	206 (PC/TP)[51]	1	206	16 hrs. (reporting: 12 hrs.; recordkeeping: 4 hrs.); $880	3,296 hrs; $181,280
Spare Equipment Strategy (one-time)	206 (PC/TP)	1	206	4 hrs. (reporting: 2 hrs.; recordkeeping: 2 hrs.); $220	824 hrs; $45,320
Plan Maintenance Outage (one-time)	206 (PC/TP)	1	206	16 hrs. (reporting: 12 hrs.; recordkeeping: 4 hrs.) $880	3,296 hrs; $181,280
TOTAL			**618**		**7,416 hrs; $407,880**

[49] We consider the filing of an application to be a "response."

[50] Hourly costs are based on the Bureau of Labor Statistics (BLS) figures for May 2017 (Sector 22, Utilities) for wages (https://www.bls.gov/oes/current/naics2_22.htm) and benefits for December 2019 (https://www.bls.gov/news.release/ecec.nr0.htm). We estimate that an Office and Administrative Support (Occupation code: 43-0000) would perform the functions associated with recordkeeping requirements, at an average hourly cost (for wages and benefits) of $41.34. The functions associated with reporting requirements, we estimate, would be performed by an Electrical Engineer (Occupation code: 17-2051) at an average hourly cost of $68.10 including wages and benefits. These occupational categories' wage figures are averaged and weighted equally as follows: ($41.34 hour + 68.10 hour) ÷ 2 = $54.72/hour. The resulting wage figure is rounded to $55.00/hour for use in calculating wage figures in the NOPR in Docket No. RM19-10-000.

[51] Entity count based on May 10, 2019 NERC Registration: 7 entities register as Planning Coordinators (PC), 137 entities register as Transmission Planners (TP), and 62 entities register as both PCs and TPs.

This notice of proposed rulemaking will not significantly change existing burdens on an ongoing basis. The Commission estimates a one-time burden increase for Year 1 only because Year 1 represents a one-time task not repeated in subsequent years.

The one-time burden for FERC-725N information collection can be averaged over three years:

- 7,416 hours ÷ 3 = 2,472 (rounded) hours/year over three years.

34. Title: FERC-725N, Mandatory Reliability Standards: Transmission Planning (TPL) Reliability Standards

Action: Proposed revision to FERC-725N information collection.

OMB Control No.: 1902-0264.

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: One Time

Necessity of the Information: This notice of proposed rulemaking proposes to approve the requested modifications to a Reliability Standard pertaining to transmission planning. As discussed above, the Commission proposes to approve proposed Reliability Standard TPL-001-5 pursuant to section 215(d)(2) of the FPA because it improves upon the currently-effective Reliability Standard TPL-001-4.

Internal Review: The Commission has reviewed proposed Reliability Standard TPL-001-5 and made a determination that its action is necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is

specific, objective support for the burden estimates associated with the information requirements.

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

36. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission, and to the Office of Management and Budget, Office of Information and Regulatory Affairs, 725 17th Street NW, Washington, DC 20503, [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-0710, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to: oira_submission@omb.eop.gov. Comments submitted to OMB should include Docket Number RM19-10-000 and FERC-725N (OMB Control No. 1902-0264).

IV. Environmental Analysis

37. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[52] The Commission has categorically excluded certain actions

[52] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

(continued…)

from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[53] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Analysis

38. The Regulatory Flexibility Act of 1980 (RFA)[54] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities.[55] The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[56] The SBA revised its size standard for electric utilities (effective January 22, 2014) to a standard based on the number of employees, including affiliates (from the prior standard based on megawatt hour sales).[57]

39. Proposed Reliability Standard TPL-001-5 is expected to impose an additional burden on 206 entities[58] (planning coordinators and transmission planners).

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[53] 18 CFR 380.4(a)(2)(ii) (2018).

[54] 5 U.S.C. 601-612 (2012).

[55] *Id.* 601-12.

[56] 13 CFR 121.101 (2018).

[57] *Id.* 121.201.

[58] Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this NOPR, we are using a 500 employee threshold due to each affected entity falling within the role of Electric Bulk Power Transmission and Control (NAISC Code: 221121).

40. Of the 206 affected entities discussed above, we estimate that approximately 10 percent of the affected entities are small entities. We estimate that each of the 21 small entities to whom the proposed modifications to proposed Reliability Standard TPL-001-5 apply will incur one-time costs of approximately $1,980 per entity to implement the proposed Reliability Standard. We do not consider the estimated costs for these 21 small entities to be a significant economic impact. Accordingly, we propose to certify that proposed Reliability Standard TPL-001-5 will not have a significant economic impact on a substantial number of small entities.

VI. Comment Procedures

41. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 60 days after publication in the FEDERAL REGISTER**]. Comments must refer to Docket No. RM19-10-000, and must include the commenter's name, the organization they represent, if applicable, and address.

42. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

43. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

44. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

45. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

46. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.User assistance is available for eLibrary and the Commission’s website during normal business hours from the Commission’s Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or e-mail at

ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD19-6-000

July 11, 2019

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Western Electricity Coordinating Council
155 North 400 West, Suite 200
Salt Lake City, UT 84103

Attention: Lauren A. Perotti
Senior Counsel for North American Electric Reliability Corporation
Steve Goodwill
Vice President, General Counsel, and Corporate Secretary and
Ruben Arredondo
Senior Legal Counsel for Western Electricity Coordinating Council

Reference: Joint Petition of the North American Electric Reliability Corporation and Western Electricity Coordinating Council for Approval of Proposed Reliability Standard IRO-002-6

Dear Ms. Perotti, Mr. Goodwill and Mr. Arredondo:

On May 30, 2019 the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) filed a joint petition seeking approval of proposed Reliability Standard IRO-002-6 (Reliability Coordination – Monitoring and Analysis), the associated violation risk factors and violation severity levels, and implementation plan. NERC and WECC state that proposed Reliability Standard IRO-002-6 reflects the addition of a regional variance containing additional requirements applicable to reliability coordinators providing service to entities in the

Western Interconnection. None of the continent-wide requirements have been changed compared with currently-effective Reliability Standard IRO-002-5.[1]

NERC's filing was noticed on May 31, 2019, with interventions, comments and protests due on or before July 1, 2019. No comments were received.

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,

Andrew Dodge, Director
Office of Electric Reliability

[1] Petition at 2.

20190614-3058 FERC PDF (Unofficial) 06/14/2019

167 FERC ¶ 61,225
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

June 14, 2019

In Reply Refer To:
North American Electric
Reliability Corporation
Docket No. RR19-4-001

North American Electric Reliability Corporation
3353 Peachtree Road, NE,
Suite 600, North Tower
Atlanta, GA 30326

Attention: Nina Jenkins-Johnston

Dear Ms. Jenkins-Johnston:

1. On May 16, 2019, the North American Electric Reliability Corporation (NERC) submitted a petition for Commission approval: (1) for a one-time advance to the Florida Reliability Coordinating Council (FRCC) up to $1,500,000 from NERC's operating contingency reserve to assist in FRCC's wind-down costs associated with its dissolution of FRCC as a Regional Entity; (2) for NERC to deviate from its Rules of Procedure to replenish its operating contingency reserves via certain penalty funds, and to the extent such penalty funds are not sufficient, via a special assessment to former FRCC registered entities; and (3) to amend the termination agreement between NERC and FRCC in accordance with NERC's requested changes, including to submit an informational report on or before June 1, 2020. In this order, we grant the approvals and direct NERC to submit an informational report, as requested.

2. On February 27, 2019, NERC, FRCC, and SERC Reliability Corporation (SERC) (collectively, Petitioners) filed a joint petition requesting certain Commission approvals in connection with the dissolution of FRCC as a Regional Entity and the transfer of registered entities within the FRCC footprint to SERC (Joint Petition). As part of the Joint Petition, Petitioners submitted for approval a termination agreement between NERC and FRCC (Termination Agreement), providing for, among other things: (1) a special assessment of up to $630,000 to assist with the wind-down costs of FRCC as a Regional Entity, and (2) Commission approval to deviate from the application of penalty monies as

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specified in section 1107 of the NERC Rules of Procedure,[1] to permit the use of penalty payments for FRCC wind-down and SERC transition costs. On April 30, 2019, the Commission granted the approvals requested in the Joint Petition.[2]

3. NERC seeks Commission approval of a one-time advance of funds from NERC's operating contingency reserves to FRCC of up to $1,500,000 to cover costs that FRCC is contractually obligated to incur to accomplish the wind-down and dissolution of FRCC as a Regional Entity. NERC explains that this advance will only be made if FRCC does not have sufficient funds on July 1, 2019 to make required payments for wind-down costs due on or before August 31, 2019. Therefore, NERC states that this one-time advance will supplement the Commission-approved $630,000 special assessment as a source of funding for FRCC's wind-down costs. NERC states that this request to advance funds to FRCC stems from an unanticipated change in FRCC's cash flow projection such that FRCC may not have sufficient funds to make payments contractually required by August 31, 2019 as part of its wind-down obligations.[3] NERC states that up to $1,500,000 can be expended from its operating contingency reserves in 2019 without adversely impacting NERC's operating contingency reserves position or its ability to meet other unanticipated contingencies that could require the use of funds in the operating contingency reserve.[4]

4. NERC states that, if deemed necessary by the Commission, NERC proposes that the treatment of this cash advance should be considered an expenditure of NERC's operating contingency reserves exceeding $500,000. NERC states that approval of this advance is in accordance with Paragraph 7(b)(ii) of the Settlement Agreement between

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[1] Section 1107.2 of the NERC Rules of Procedure provides that:

> All funds from financial Penalties assessed in the United States received by the entity initiating the compliance monitoring and enforcement process shall be applied as a general offset to the entity's budget requirement for the subsequent fiscal year, if received by July 1, or for the second subsequent fiscal year, if received on or after July 1. Funds from financial Penalties shall not be directly applied to any program maintained by the entity conducting the compliance monitoring and enforcement process.

[2] *See North American Electric Reliability Corp.*, 167 FERC ¶ 61,095 (2019) (Dissolution Order).

[3] Filing at 2-3.

[4] *Id.* at 6.

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NERC and the Commission in Docket No. FA11-21-000 and NERC's Working Capital and Operating Reserve Policy (Reserve Policy).[5] NERC states that the Reserve Policy provides that operating contingency reserves are maintained for "contingencies that were not anticipated, assumed to be likely or the timing of which was uncertain, at the time of preparation and approval of the company's business plan and budget." For operating contingency reserve expenditures in excess of $1 million, "approval of the Board [of Trustees] is required, after notice to and recommendation by the Finance and Audit Committee." NERC states that the NERC Board of Trustees approved the proposed expenditure on May 7, 2019.[6]

5. NERC also seeks permission to replenish its operating contingency reserves up to the amount advanced to FRCC for wind-down costs, through penalty funds received on or before February 29, 2020 from registered entities within the former FRCC footprint. In order to replenish its reserves using these penalty funds, NERC seeks Commission approval to deviate from any applicable rules and policies, including section 1107 of the NERC Rules of Procedure regarding the treatment of penalty monies.[7] NERC states that any penalty funds exceeding the amount NERC advances to FRCC will be reimbursed to the load-serving entities within the former FRCC footprint on a *pro rata* basis based on net energy for load.

6. If sufficient penalty funds have not been received by February 29, 2020, NERC requests approval, pursuant to section 1108 of the NERC Rules of Procedure,[8] to allow

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[5] *See North American Electric Reliability Corp.*, 142 FERC ¶ 61,042 (2013). *See* P 7(b)(ii) of the Settlement Agreement attached to the order.

[6] Filing at 3, 5-6

[7] *Id*. at 7.

[8] Section 1108 of the NERC Rules of Procedure provides that:

> On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next funding cycle, NERC shall file with the [Commission]… for authorization for an amended or supplemental budget for NERC or a Regional Entity and, if necessary under the amended or supplemental budget, to collect a special or additional assessment for statutory functions of NERC or the Regional Entity. Such a filing shall include supporting materials to justify the requested funding, *including any departure from the approved funding formula or method*. (emphasis added)

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NERC to replenish its operating contingency reserves up to the amount advanced to FRCC for wind-down costs using a special assessment solely to load-serving entities within the former FRCC footprint.[9] To allow such a special assessment, NERC seeks approval for a departure from the allocation requirements for funding statutory activities specified in section 1102 of the NERC Rules of Procedure.[10] NERC states that the special assessment would apply solely to the former FRCC load-serving entities because the proposed advance to FRCC will have facilitated the successful wind down of FRCC as a Regional Entity. NERC states that it would bill the FRCC load-serving entities on the same basis as they were billed for the initial special assessment authorized in the Dissolution Order. NERC states that it would issue the special assessment, if and to the extent required, by March 1, 2020, with a payment due date within 45 days.[11]

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[9] Filing at 8.

[10] Section 1102 of the NERC Rules of Procedure provides that:

1. In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on Net Energy for Load (NEL).
2. NERC's costs shall be allocated so that all Load (or, in the case of costs for an Interconnection or Regional Entity, all Load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.
3. Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.
4. Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on Net Energy for Load.

[11] Filing at 8.

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7. In addition, NERC proposes to amend the Termination Agreement consistent with its requests and to reflect its commitment to submit an informational report to the Commission on or before June 1, 2020. NERC states that the informational report will document whether an advance from NERC's operating contingency reserves was provided to FRCC, and in what amount, with supporting information showing how the specific amount advanced was determined. NERC states that it will also detail how and from what sources (consistent with the requests approved by the Commission) NERC replenished its operating contingency reserves.[12]

8. Notice of NERC's May 16, 2019 filing was published in the *Federal Register*, 84 Fed. Reg. 24,130 (2019), with interventions and protests due on or before May 28, 2019. None were filed.

9. We grant the requested approvals needed to continue the dissolution of FRCC as a Regional Entity by August 31, 2019, as previously approved by the Commission. Specifically, we approve NERC's request to make a one-time advance to FRCC of up to $1,500,000 from NERC's operating contingency reserve in order for FRCC to complete the wind-down of its role and responsibilities as a Regional Entity, subject to NERC making a future informational report on or before June 1, 2020, as NERC commits to in its petition.[13]

10. We also grant NERC's request to deviate from the requirements of section 1107 of the NERC Rules of Procedure to allow NERC to replenish its operating contingency reserves up to the amount advanced to FRCC for wind-down costs using penalty funds received from registered entities within the former FRCC footprint on or before February 29, 2020. We also grant NERC's request to reimburse any excess penalty funds to the load-serving entities within the former FRCC footprint on a *pro rata* basis based on net energy for load.

11. To the extent that any such penalty funds do not fully cover the amount advanced to FRCC, we approve NERC's request to replenish its operating contingency reserves up to the amount advanced to FRCC through a special assessment, pursuant to section 1108 of the NERC Rules of Procedure, issued by March 1, 2020 with a payment due within 45 days. Furthermore, we grant NERC's request to deviate from the requirements of section 1102 of the NERC Rules of Procedure to allow NERC to apply the special

[12] *Id*. at 9.

[13] In approving the request, we need not determine, and we make no determination here regarding, whether Paragraph 7(b)(ii) of the Settlement Agreement applies in this case.

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assessment solely to the load-serving entities in the former FRCC footprint on the same basis as they were billed for the initial special assessment authorized in the Dissolution Order.

12. Finally, we approve NERC's proposed amendments to the Termination Agreement to reflect the actions approved in this order and the proposed informational report.

By direction of the Commission.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

20190614-3058 FERC PDF (Unofficial) 06/14/2019

Document Content(s)

RR19-4-001.DOCX.....1-6

167 FERC ¶ 61,230
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

June 20, 2019

In Reply Refer To:
North American Electric Reliability
Corporation
Docket No. RD19-3-000

North American Electric Reliability Corporation
1325 G Street, NW
Suite 600
Washington, DC 20005

Attention: Lauren Perotti
Marisa Hecht

Dear Ms. Perotti and Ms. Hecht:

1. On March 7, 2019, the North American Electric Reliability Corporation (NERC) filed a petition requesting approval of proposed Reliability Standard CIP-008-6 (Cyber Security – Incident Reporting and Response Planning). NERC also requested approval of: (1) the associated implementation plan, violation risk factors and violation severity levels; (2) the inclusion of proposed revised definitions of "Cyber Security Incident" and "Reportable Cyber Security Incident" into the NERC Glossary;[1] and (3) the retirement of currently-effective Reliability Standard CIP-008-5. For the reasons discussed below, we grant the requested approvals.

2. In Order No. 848, the Commission directed NERC to enhance the mandatory reporting of Cyber Security Incidents.[2] The Commission explained that the currently-effective reporting threshold, which only requires reporting in cases where a Cyber Security Incident has "compromised or disrupted one or more reliability tasks," may

[1] Glossary of Terms Used in NERC Reliability Standards (NERC Glossary).

[2] *Cyber Security Incident Reporting Reliability Standards*, Order No. 848, 164 FERC ¶ 61,033 (2018).

(continued ...)

understate the true scope of cyber-related threats to the Bulk-Power System.[3] To address this reliability gap, pursuant to section 215(d)(5) of the Federal Power Act (FPA), the Commission directed NERC to develop and submit modifications to the Reliability Standard to require the reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's Electronic Security Perimeter (ESP) or associated Electronic Access Control or Monitoring Systems (EACMS).[4] With respect to EACMS, the Commission directed that enhanced reporting should apply, at a minimum, to EACMS that perform the following functions: (1) authentication; (2) monitoring and logging; (3) access control; (4) Interactive Remote Access; and (5) alerting.

3. The Commission also directed that 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.[5] The Commission further directed that filing deadlines for Cyber Security Incident reports should be established and that Cyber Security Incident reports should be sent to the Electricity Information Sharing and Analysis Center (E-ISAC) and the Department of Homeland Security Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) or any successor organization.

4. In its petition, NERC states that proposed Reliability Standard CIP-008-6 broadens the mandatory reporting of Cyber Security Incidents and thus addresses the concern that currently-effective Reliability Standard CIP-008-5 may not encompass the full scope of cyber-related threats to the Bulk-Power System.[6] As a predicate to the augmented reporting requirements in proposed Reliability Standard CIP-008-6, NERC proposes revised NERC Glossary definitions of Cyber Security Incident and Reportable Cyber Security Incident. NERC explains that, by applying the revised definitions, Cyber Security Incidents (i.e., attempts to compromise) and Reportable Cyber Security Incidents (i.e., actual compromises) will be reported under proposed Reliability Standard CIP-008-6.

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[3] *Id.* PP 2-3.

[4] 16 U.S.C. 824o(d)(5) (2012).

[5] The Commission identified the following minimum fields of information to be reported: "(1) the functional impact, where possible, that the Cyber Security Incident achieved or attempted to achieve; (2) the attack vector that was used to achieve or attempted to achieve the Cyber Security Incident; and (3) the level of intrusion that was achieved or attempted or as a result of the Cyber Security Incident." Order No. 848, 164 FERC ¶ 61,033 at P 91.

[6] NERC Petition at 3.

(continued ...)

5. As proposed by NERC, the revised Cyber Security Incident definition includes events involving "compromises or attempts to compromise" ESPs, EACMS, and Physical Security Perimeters (PSPs) associated with high and medium impact BES Cyber Systems and "disrupt[ion] or attempts to disrupt the operation of a BES Cyber System."[7] NERC contends that the proposed definition of Cyber Security Incident addresses the directives in Order No. 848 because, as discussed below, once a responsible entity determines that an event is a Cyber Security Incident, it must comply with the requirements of proposed Reliability Standard CIP-008-6, including initiating its response plan and reporting the incident to the E-ISAC and, if subject to the jurisdiction of the United States, the National Cybersecurity and Communications Integration Center (NCCIC), which is the successor to ICS-CERT.

6. NERC's proposed revisions to the Reportable Cyber Security Incident definition broaden the scope of reportable events to include compromises or disruptions of BES Cyber Systems that perform one or more reliability tasks as well as compromises or disruptions to EACMS and ESPs associated with high and medium impact BES Cyber Systems. NERC explains that responsible entities will be required to report on a compromise of a BES Cyber System even if it has not affected performance of that BES Cyber System's tasks.[8] For example, NERC states that the revised definition would require responsible entities to report on malware installed on a BES Cyber Asset component of a BES Cyber System that performs one or more reliability tasks regardless of whether the BES Cyber System still operates. NERC indicates that while the revised Reportable Cyber Security Incident definition does not encompass attempts to compromise, under proposed Reliability Standard CIP-008-6, attempts to compromise are reported using the Cyber Security Incident definition.

7. NERC states that proposed Reliability Standard CIP-008-6, Requirement R1, Parts 1.2.1 and 1.2.2 address the Order No. 848 directive to broaden reporting on Cyber Security Incidents to include those that "attempt to compromise" an ESP or EACMS.[9] In proposed Requirement R1, Part 1.2.1, each responsible entity must develop a process that includes criteria to evaluate and define attempts to compromise applicable systems. Proposed Requirement R1, Part 1.2.2 requires that each responsible entity develop a

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[7] NERC indicates that the standard drafting team included all EACMS within the proposed Cyber Security Incident and Reportable Cyber Security incident definitions because nearly all EACMS associated with high and medium impact BES Cyber Systems perform one of the functions identified in Order No. 848. *Id.* at 13-14.

[8] *Id.* at 15.

[9] *Id.* at 18.

(continued ...)

process that identifies whether a Cyber Security Incident is an "attempt to compromise" pursuant to the criteria required by Part 1.2.1. NERC explains that Parts 1.2.1 and 1.2.2 work together to help ensure each responsible entity first develops criteria for identifying an attempt to compromise and then applies the criteria during its Cyber Security Incident identification process.[10] NERC maintains that proposed Parts 1.2.1 and 1.2.2 acknowledge the differences in system architecture among responsible entities and provide each responsible entity with the flexibility to develop criteria that reflect what it considers "suspicious." NERC contends that the benefit of such an approach, compared to a one-size-fits-all approach, is that it enables responsible entities to better capture real attempts to compromise.[11]

8. Similar to the proposed revisions in Requirement R1, NERC states that the proposed revisions to Reliability Standard CIP-008-6, Requirement R2 address the Commission's directive in Order No. 848 regarding attempts to compromise.[12] The proposed revisions to Part 2.2 do so by requiring that responsible entities use their Cyber Security Incident response plans when responding to a Cyber Security Incident determined to be an attempt to compromise applicable systems.

9. NERC contends that proposed Reliability Standard CIP-008-6, Requirement R4 addresses the Commission's directive to require that responsible entities must send each report and update to the E-ISAC and ICS-CERT.[13] Under proposed Reliability Standard CIP-008-6, Requirement R4, Part 4.1, responsible entities are required to submit incident reports for both Reportable Cyber Security Incidents and Cyber Security Incidents. In addition, proposed Reliability Standard CIP-008-6 specifies that the report must contain: (1) the functional impact; (2) the attack vector used; and (3) the achieved or attempted level of intrusion. Proposed Reliability Standard CIP-008-6, Requirement R4, Parts 4.2 and 4.3 include timelines for initial reports as well as follow up reports to the E-ISAC and NCCIC. NERC states that initial reports for Reportable Cyber Security Incidents must occur within one hour of its determination. By contrast, NERC indicates that once a responsible entity has determined that a Cyber Security Incident meets its criteria for an

[10] *Id.*

[11] *Id.* at 19.

[12] *Id.* at 20.

[13] *Id.* at 22.

attempt to compromise an applicable system, it must report the Cyber Security Incident by the end of the next calendar day. NERC justifies the difference by explaining that the "proposed notification timelines appropriately reflect the severity of the risk of the respective incidents."[14] Finally, if a responsible entity does not include one or more of the attributes in its initial report because it was unknown at the time of the initial reporting, it must report the attributes within seven days of determining the attribute.

10. Notice of NERC's March 7, 2019 filing was published in the *Federal Register*, 84 FR 10,061 (2019), with interventions and protests due on or before April 11, 2019. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. 385.214 (2018), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.[15]

11. Pursuant to section 215(d)(2) of the FPA, we approve Reliability Standard CIP-008-6, its associated implementation plan, violation risk factors and violation severity levels, and the revised definitions of Cyber Security Incident and Reportable Cyber Security Incident.[16] We determine that the proposed Reliability Standard and revised definitions satisfy the directive in Order No. 848 to broaden mandatory reporting to include Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS, as well as modifications to specify the required information in Cyber Security Incident reports, their dissemination, and deadlines for filing reports.

Information Collection Statement

12. In compliance with the requirements of the Paperwork Reduction Act of 1995, 44 USC 3506(c)(2)(A), the Commission is soliciting public comment on revisions to the information collection FERC-725B (Mandatory Reliability Standards for Critical Infrastructure Protection (CIP) Reliability Standards), which will be submitted to the Office of Management and Budget (OMB) for a review of the information collection requirements. Comments on the collection of information are due within 60 days of the

[14] *Id.* at 23.

[15] On April 11, 2019, Public Citizen submitted comments requesting that the Commission direct NERC to require the mandatory public disclosure of entity names in Notices of Penalty for violations of Critical Infrastructure Protection Reliability Standards. Public Citizen's comments do not address proposed Reliability Standard CIP-006-8 or any other proposal contained in NERC's petition, and they are therefore outside the scope of this proceeding.

[16] 16 U.S.C. 824o(d)(2).

(continued ...)

date this order is published in the *Federal Register*. Respondents subject to the filing requirements of this order will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

13. Proposed Reliability Standard CIP-008-6 requires Responsible Entities[17] to broaden the mandatory reporting of Cyber Security Incidents to include compromises or attempts to compromise BES Cyber Systems or their associated ESPs or EACMS. The revised Reliability Standard will not significantly increase the reporting burden on entities because it builds off the currently-effective reporting threshold by expanding it to address reliability gaps, pursuant to section 215(d)(5) of the FPA.

14. Burden[18] Estimate: The Commission estimates the changes in the annual public reporting burden and cost as indicated below.[19]

RD19-3-000 Commission Letter Order (Mandatory Reliability Standards for Critical Infrastructure Protection Reliability Standards)						
	Number of Respondents & Type of Entity[20] (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response[21] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**

[17] "Responsible Entities" refers to Balancing Authority (BA), Distribution Provider (DP), Generator Operator (GOP), Generator Owner (GO), Reliability Coordinator (RC), Transmission Operator (TOP), and Transmission Owner (TO).

[18] Burden is defined as the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the information collection burden, refer to 5 C.F.R. 1320.3.

[19] For the Reliability Standard being retired in Docket No. RD19-3-000, the baseline numbers for respondents, burden, and cost are the same figures as those in Order No. 848. The requirements and burdens (from the Reliability Standard being retired) are continuing in Reliability Standard CIP-008-6, plus the additional requirements and burdens as indicated in the table.

[20] There are 1,414 unique registered entities in the NERC compliance registry as of May 24, 2019. Of this total, we estimate that 288 entities will face an increased paperwork burden.

[21] The loaded hourly wage figure (includes benefits) is based on the average of the occupational categories for 2017 found on the Bureau of Labor Statistics website:
(continued ...)

Update internal procedures to comply with augmented reporting requirements. (one-time)[22] (CIP-008-6 R1-R4)	288	1	288	50 hrs.; $4,050	14,400 hrs.; $1,166,400	$4,050
Annual cyber security incident plan review (ongoing)[23] (CIP-008-6 R2.1)	288	1	288	10 hrs.; $810	2880 hrs.; $233,280	$810
Update cyber security incident plan per review findings (ongoing) (CIP-008-6 R3)	288	1	288	10 hrs.; $810	2880 hrs.; $233,280	$810
Incident reporting burden (ongoing) (CIP-008-6 R4)	288	12	3456	12 hrs.; $972	3456 hrs.; $279,936	$972
TOTAL (one-time)			**288**		**14,400 hrs.; $1,166,400**	
TOTAL (ongoing)			**4032**		**9,216 hrs.; $746,496**	

https://www.bls.gov/oes/2017/may/oessrci.htm.

Legal (Occupation Code: 23-0000): $143.68
Information Security Analysts (Occupation Code 15-1122): $61.55
Computer and Information Systems Managers (Occupation Code: 11-3021): $96.51
Management (Occupation Code: 11-0000): $94.28
Electrical Engineer (Occupation Code: 17-2071): $66.90
Management Analyst (Code: 43-0000): $63.32

These various occupational categories are weighted as follows: [($94.28)(.10) + ($61.55)(.315) + ($66.90)(.02) + ($143.68)(.15) + ($96.51)(.10) + ($63.32)(.315)] = $81.30. The figure is rounded to $81.00 for use in calculating wage figures in this order.

[22] One-time burdens apply in Year 1 only.

[23] Ongoing burdens apply in Year 2 and beyond.

Title: FERC-725B, Mandatory Reliability Standards for Critical Infrastructure Protection (CIP) Reliability Standards.

Action: Proposed revision to FERC-725B information collection.

OMB Control No: 1902-0248.

Respondents: Responsible Entities.

Frequency of Responses: On occasion.

15. Necessity of the Information: This order approves the requested modifications to Reliability Standards pertaining to critical infrastructure protection. As discussed above, the Commission approves Reliability Standard CIP-008-6 pursuant to section 215(d)(2) of the FPA because it improves upon the currently-effective suite of CIP Reliability Standards.

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

17. Comments (identified by Docket No. RD19-3-000) concerning the collection of information and the associated burden estimate(s) may also be sent by either of the following methods: eFiling at Commission's Web Site: http://www.ferc.gov/docs-filing/efiling.asp or Mail/Hand Delivery/Courier: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426. Please refer to FERC-725B, OMB Control No. 1902-0248 in your submission.

18. All submissions must be formatted and filed in accordance with submission guidelines at: http://www.ferc.gov/help/submission-guide.asp. For user assistance, contact FERC Online Support by e-mail at ferconlinesupport@ferc.gov, or by phone at: (866) 208-3676 (toll-free), or (202) 502-8659 for TTY.

By direction of the Commission.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD19-5-000

July 31, 2019

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Marisa Hecht
Counsel for North American Electric Reliability Corporation

Reference: Approval of Reliability Standard CIP-003-8 (Cyber Security - Security Management Controls)

Dear Ms. Hecht:

On May 21, 2019, the North American Electric Reliability Corporation (NERC) submitted a filing seeking Commission approval of Reliability Standard CIP-003-8 (Cyber Security — Security Management Controls). NERC requests Commission approval of proposed Reliability Standard CIP-003-8; the associated implementation plan, violation risk factors and violation severity levels; and the retirement of Commission-approved Reliability Standard CIP-003-7.

The purpose of Reliability Standard CIP-003-8 is 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. NERC filed the petition in response to the Commission's directive in Order No. 843 to develop modifications to the Reliability Standards to mitigate the risk of malicious code

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that could result from third-party transient electronic devices for low impact BES Cyber Systems[1].

NERC's petition was noticed on May 21, 2019, with interventions, comments and protests due on or before June 12, 2019. No interventions, comments or protests were received.

NERC's uncontested petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability, under 18 C.F.R. § 375.303 (2018), effective as of the date of this order.

This action shall not be construed as accepting any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders which have been or which may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2018).

Sincerely,

Andrew Dodge, Director
Office of Electric Reliability

[1] *Revised Critical Infrastructure Protection Reliability Standard CIP-003-7 – Cyber Security – Security Management Controls*, Order No. 843, 163 FERC ¶ 61,032, at P 37 (2018).

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Document Content(s)

RD19-5-000.DOCX.....1-2

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

July 11, 2019

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. No. 94-409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING:	FEDERAL ENERGY REGULATORY COMMISSION
DATE AND TIME:	July 18, 2019 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.

1058th - MEETING

OPEN MEETING

July 18, 2019

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD19-1-000	Agency Administrative Matters
A-2	AD19-2-000	Customer Matters, Reliability, Security and Market Operations
		ELECTRIC
E-1	RM16-17-000	Data Collection for Analytics and Surveillance and Market-Based Rate Purposes
E-2	RM19-2-000	Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets
E-3	RM18-15-001	Interlocking Officers and Directors; Requirements for Applicants and Holders
E-4	QF18-452-000	North American Natural Resources, Inc.
E-5	NJ19-10-000	Western Area Power Administration
E-6	ER19-1876-000	Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Duke Energy Florida, LLC
E-7	ER18-2370-001	Lackawanna Energy Center LLC
E-8	ER19-585-001	Quilt Block Wind Farm LLC
E-9	ER19-266-001	Invenergy Nelson LLC
E-10	ER18-1222-005	PSEG Energy Resources & Trade LLC
E-11	ER18-1737-002 ER18-1737-004	Northern Indiana Public Service Company LLC

E-12	OMITTED	
E-13	ER14-2529-005 ER15-2294-004 ER16-2320-004 (consolidated)	Pacific Gas and Electric Company
E-14	ER11-2774-003 ER12-303-003	Virginia Electric and Power Company Dominion Energy Generation Marketing, Inc. Dominion Energy Nuclear Connecticut, Inc. Dominion Bridgeport Fuel Cell, LLC NedPower Mount Storm, LLC Fowler Ridge Wind Farm LLC South Carolina Electric & Gas Company
	ER11-2774-004	Virginia Electric and Power Company Dominion Energy Generation Marketing, Inc. Dominion Energy Nuclear Connecticut, Inc. Dominion Bridgeport Fuel Cell, LLC Dominion Energy South Carolina, Inc.
E-15	EL18-48-002	Gregory and Beverly Swecker v. Midland Power Cooperative and Central Iowa Power Cooperative
	QF11-424-007	Gregory and Beverly Swecker
E-16	EL18-140-001	Consumers Energy Company, Interstate Power and Light Company, Midwest Municipal Transmission Group, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, and WPPI Energy v. International Transmission Company, ITC Midwest, LLC, and Michigan Electric Transmission Company
E-17	OMITTED	
E-18	OMITTED	
E-19	EL15-70-000	Public Citizen, Inc. v. Midcontinent Independent System Operator, Inc.
	EL15-71-000	The People of the State of Illinois By Illinois Attorney General Lisa Madigan v. Midcontinent Independent System Operator, Inc.
	EL15-72-000	Southwestern Electric Cooperative, Inc. v. Midcontinent Independent System Operator, Inc., Dynegy, Inc., and Sellers of Capacity into Zone 4 of the 2015-2016 MISO Planning Resource Auction

GAS

G-1	PR17-60-001 PR17-60-002	Atmos Pipeline-Texas
G-2	RP18-1126-001	Transcontinental Gas Pipe Line Company, LLC

HYDRO

H-1	P-13-036	Green Island Power Authority and Albany Engineering Corporation

CERTIFICATES

C-1	CP18-525-000	Gulf South Pipeline Company, LP
C-2	CP19-3-000	Gulf South Pipeline Company, LP
C-3	CP18-485-000	Texas Eastern Transmission, LP Transcontinental Gas PipeLine Company, LLC
	CP18-486-000	Texas Eastern Transmission, LP Transcontinental Gas PipeLine Company, LLC Northern Natural Gas Company
	CP18-505-000	Texas Eastern Transmission, LP

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 Shirley Al-Jarani at 703-993-3104.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

July 2019
Commission Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its July 18, 2019 public meeting. The summaries are produced by FERC's Office of External Affairs and are intended to provide only a general synopsis of the orders. These summaries are not intended as a substitute for the Commission's official orders. To determine the specific actions and the Commission's reasoning, please consult the individual orders when they are posted to FERC's eLibrary found at www.ferc.gov.

E-1 & E-2 – Press Release

FERC grants in part and denies in part requests for rehearing and clarification

E-3, *Interlocking Officers and Directors; Requirements for Applicants and Holders,* Docket No. RM18-15-001. In Order No. 856, the Commission revised its regulations related to interlocking officers and directors. In this order on rehearing, the Commission grants in part and denies in part requests for rehearing and clarification of Order No. 856.

FERC rejects a refund report, directs filing of revised report

E-4, *North American Natural Resources, Inc*., Docket No. QF18-452-000. This order rejects NANR's Refund Report and directs NANR to recalculate the refund amounts, make time value refunds, and file a revised refund report with the Commission within 30 days of the issuance date of the order.

FERC grants in part and denies in part a petition for declaratory order

E-5, *Western Area Power Administration*, Docket No. NJ19-10-000. The order grants in part and denies in part a petition for declaratory order filed by Western, finding that Western's tariff changes substantially conform to, or are superior to, the *pro forma* Open Access Transmission Tariff (OATT), but also finds that Western's tariff, as revised, is not now an acceptable reciprocity tariff because it has not implemented changes to the *pro forma* OATT called for by recent Commission Orders.

FERC grants requested waivers

E-6, *Duke Energy Carolinas, LLC, et al.,* Docket No. ER19-1876-000. The order grants waivers requested by Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Duke Energy Florida, LLC (collectively, Duke Southeast Companies). The waivers will allow Duke Southeast Companies to make adjustments to their 2019 Annual Updates of their formula transmission rates to eliminate the impact of excess accumulated deferred income taxes resulting from the Tax Cuts and Jobs Act, and to hold customers harmless from a potential rate base increase.

FERC approves an uncontested settlement

E-7, *Lackawanna Energy Center LLC*, Docket No. ER18-2370-001 *et al.* This letter order approves an uncontested settlement concerning the revenue requirement for reactive service by Lackawanna from its natural gas-fired electric generation facility in Jessup, Pennsylvania.

FERC approves an uncontested settlement

E-8, *Quilt Block Wind Farm LLC*, Docket No. ER19-585-001. This letter order approves an uncontested settlement concerning Quilt Block's annual revenue requirement for providing Reactive Supply and Voltage Control from Generation or Other Sources Service from the Quilt Block Facility under Schedule 2 of the Midcontinent Independent System Operator, Inc. tariff.

FERC approves an uncontested settlement

E-9, *Invenergy Nelson LLC*, Docket No. ER19-266-001. This letter order approves an uncontested settlement concerning the revenue requirement for reactive service by Invenergy Nelson from its natural gas-fired electric generation facility near Rock Falls, Illinois.

FERC approves an uncontested settlement

E-10, *PSEG Energy Resources & Trade LLC*, Docket No. ER18-1222-005. The letter order approves PSEG ER&T's uncontested settlement concerning PSEG ER&T's rates for reactive service from two newly constructed generation units: Sewaren Urban Entity LLC and PSEG Keys Energy Center LLC.

FERC approves an uncontested settlement

E-11, *Northern Indiana Public Service Company LLC*, Docket Nos. ER18-1737-002 & -004. This letter order approves an uncontested settlement concerning NIPSCO's annual revenue requirement for providing Reactive Supply and Voltage Control from Generation or Other Sources Service from each generating facility in NIPSCO's generation fleet under Schedule 2 of the Midcontinent Independent System Operator, Inc. tariff.

FERC reaffirms actions on remand

E-13, *Pacific Gas and Electric Company*, Docket No. ER14-2529-005, *et al.* This order on remand from the U.S. Court of Appeals for the 9th Circuit reaffirms the Commission's prior grant of PG&E's request for a 50 basis point return-on-equity adder to its transmission rates for its continuing membership in the California Independent System Operator Corporation (CAISO). In doing so, the order finds that California law does not mandate PG&E's participation in CAISO and that the incentive induces PG&E to continue its membership.

FERC accepts notices of change of status

E-14, *Virginia Electric and Power Co.*, Docket No. ER11-2774-003. The order accepts notices of change in status filed by Dominion Energy Services, Inc. concerning previously granted limited waivers of the separation of functions requirement in the market-based rate affiliate restrictions.

FERC denies request for rehearing or reconsideration

E-15, *Gregory and Beverly Swecker v. Midland Power Cooperative, Central Iowa Power Cooperative; Swecker, Gregory and Beverly*, Docket Nos. EL18-48-002 and QF11-424-007. The order denies the Sweckers' request for rehearing or reconsideration of the Commission's March 1, 2019 order, which denied their earlier request for clarification of the Commission's January 30, 2018 Notice of Intent Not to Act.

FERC denies a request for rehearing

E-16, *Consumers Energy Co.,* Docket No. EL18-140-001. This order denies a request for rehearing of an October 18, 2018 order that found that the return on equity adders for being independent, stand-alone transmission companies previously awarded to the ITC Companies had become unjust and unreasonable following a recent Commission-authorized merger. The order affirms the Commission's finding that the merger reduced, but did not eliminate, the ITC Companies' independence, and denies rehearing.

FERC address complaints

E-19, *Public Citizen, Inc. v. Midcontinent Independent System Operator, Inc.*, *et al.*, Docket No. EL15-70-000, *et al*. The order addresses the remaining arguments raised in complaints regarding the results of MISO's 2015/16 Planning Resource Auction for Local Resource Zone 4. On December 31, 2015, the Commission granted the complaints in part and found that certain provisions in the MISO tariff governing the Auction were no longer just and reasonable for prospective application. The order voted today (1) grants motions to dismiss and other pleadings by entities asserting that the complaint against sellers of capacity into Zone 4 during the 2015/16 Auction does not make them respondents; (2) declines requests to hold an evidentiary hearing to resolve issues related to the 2015/16 Auction; and (3) finds that the results of the 2015/16 Auction for Zone 4 were just and reasonable.

FERC orders revisions to a Statement of Operating Conditions

G-1, *Atmos Pipeline-Texas*, Docket No. PR17-60-001/-002. The order finds that Atmos' proposed section 10.1 of its Statement of Operating Conditions (SOC) unduly discriminates against interruptible service under Natural Gas Policy Act (NGPA) section 311 by giving it a lower priority than equivalent intrastate interruptible service. As a result, the order directs Atmos to revise its SOC so as not to subordinate NGPA section 311 interruptible service to intrastate interruptible transportation. The order also rules on newly proposed language on scheduling in section 10.2 of the SOC. In accordance with Commission policy, the order directs Atmos to revise section 10.2 to clarify that interruptible shippers with discounted rates have the option to pay a higher rate up to the maximum interruptible rate during a constrained period in order to obtain a higher scheduling priority or avoid curtailment.

FERC denies request for rehearing

G-2, *Transcontinental Gas Pipe Line Company, LLC*, Docket No. RP18-1126-001. The order denies a request for rehearing of the Commission's September 28, 2018 order suspending, subject to hearing, revised tariff records filed by Transco in order to implement a general rate increase. The order denies the request that the Commission reverse its determination that certain issues concerning imbalance management and data entry should not be addressed in the scheduled hearing.

FERC denies in part and grants in part rehearing, denies request for stay and technical conference

H-1, *Green Island Power Authority and Albany Engineering Corporation,* Project No. 13-036. The order denies in part and grants in part Green Island Power Authority and Albany Engineering Corporation's request for rehearing of staff's October 3, 2018 Compliance Order finding that the co-licensees are in violation of a number of license terms and conditions set forth in the August 2012 license issued for the Green

Island Hydroelectric Project located at the U.S. Army Corps of Engineers' Green Island-Troy Lock and Dam on the Hudson River in Albany County, New York. The 2018 Compliance Order found that the licensees are in violation of a number of license requirements. The Commission grants rehearing with respect to one of the violations, denies rehearing with respect to the other violations, and denies licensees' request for stay and to convene a technical conference.

FERC conditionally authorizes new interstate natural gas facilities

C-1, *Gulf South Pipeline Company, LP,* Docket No. CP18-525-000. The order grants Gulf South authorization, subject to certain conditions, to construct and operate the Willis Lateral Project in Polk, Montgomery, and San Jacinto counties, Texas, designed to provide up to 200,000 dekatherms per day of firm transportation service to Entergy Texas, Inc.'s Montgomery Power Station.

FERC conditionally authorizes a new interstate natural gas infrastructure project

C-2, *Gulf South Pipeline Company, LP*, Docket No. CP19-3-000. The order conditionally authorizes Gulf South to construct and operate two new compressor units within the existing Petal III Compressor Station building, a dehydration unit, thermal oxidizer and other appurtenant facilities adjacent to the station, located in Forrest County, Mississippi. The proposed project would increase the certificated injection capability of the Petal Gas Storage Complex to 1.738 billion cubic feet per day. The proposed project would also restate the certificated withdrawal capability of the Petal Complex to reflect the withdrawal capability of the above-ground facilities, rather than the aggregate withdrawal capability of the storage caverns. The project is designed to enhance Gulf South's operational flexibility and potentially increase the number of injection and withdrawal cycles to meet its customers' needs. The order also grants Gulf South's request for authority to continue to charge market-based rates for its firm and interruptible storage services.

FERC authorizes the abandonment of certain interstate natural gas facilities

C-3, *Texas Eastern Transmission, LP and Transcontinental Gas Pipe Line Company, LLC,* Docket No. CP18-485-000*, Texas Eastern Transmission, LP, Transcontinental Gas Pipe Line Company, LLC and Northern Natural Gas Company,* Docket No. CP18-486-000, *Texas Eastern Transmission, LP,* Docket No. CP18-505-000. The order grants requests filed by Texas Eastern, Transco, and Northern Natural in Docket Nos. CP18-485-000 and CP18-486-000 to abandon gathering laterals and related facilities in offshore federal waters in the Gulf of Mexico near Louisiana, and grants Texas Eastern's request to abandon the remainder of its Cameron System in Docket No. CP18-505-000.
The order notes that there are currently no firm or interruptible shippers that would be impacted by the abandonment proposal.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Loss of Monitoring or Control Capability due to Power Supply Failure

Primary Interest Groups
Transmission Owners (TOPs)
Reliability Coordinators (RCs)
Balancing Authorities (BAs)

Problem Statement
Several entities have experienced energy management system (EMS) outages due to power supply failure.

Details
Stable and secure power supplies are critical to control rooms, data centers, and substations. Power supplies typically include normal power supply (e.g., utility feeders), standby power supply (e.g., diesel generators), and uninterruptible power supply (UPS).

During the seven EMS outages that are reviewed in this Lessons Learned document, system operator's situational awareness was degraded due to power supply failure.

Case 1:
Maintenance was scheduled at a switching center. According to the procedure, normal power supply was disconnected. However, the automatic transfer switch (ATS) failed to transfer to the standby power supply, an emergency diesel generator. All load was carried on the building UPS battery system. An EMS alarm was generated and sent to both the system operator and the transmission dispatcher.

Maintenance personnel were dispatched to investigate the status of both the main ATS and the emergency generator. The personnel informed the dispatcher that load would remain available for up to eight hours on the UPS battery system. The center experienced a total loss of facility power two hours later, including all EMS workstations. It was later discovered that the UPS battery system actually had only two hours of capacity, not eight hours. The emergency generator failed to start due to a 240v regulator failure.

Case 2:
Maintenance was scheduled to perform a planned building power supply switchgear outage as part of a switchgear upgrade project. The switchgear outage involved an interruption of the UPS power input while maintaining the UPS loads with the battery system. Before removing the UPS power input, facility maintenance personnel verified the UPS system was fully charged and had a 24-minute run time at full load.

Charging power was restored to the UPS nine minutes later. At that time, the FM personnel noticed that the UPS control panel was indicating zero charge on the batteries and recognized that the UPS loads had been de-energized.

Meanwhile, the EMS recorded remote terminal unit (RTU) failure and hardware failure and the EMS servers went offline. The RTU failures were due to loss of power to the "RAD" multiplexers that are normally fed off UPS A/C. The RTUs in the field require the availability of the redundant RAD Multiplexers at both the primary control center (PCC) and backup control center. The loss of the multiplexers at the PCC caused the RTUs in the field to suspend communications.

The entity had just had the UPS maintained and tested satisfactorily by the vendor two months prior. The UPS tests were performed under a normal UPS configuration while connected to float charge, and the batteries were not removed from the float to observe voltage drop at a resting state. The faster discharge rate was determined to be due to a lower battery capacity and not a faster discharge rate.

Case 3:

A communication path between a substation and the control center was lost due to a power supply failure that was caused by loss of a fuse at the substation. The system operator received a pop-up text message about the loss of communication path but failed to notice as it was not an audible alarm. This resulted in a loss of ability to control BES elements at the substation for three hours.

Case 4:

An entity lost multiple RTUs, resulting in stale data being used for the results of EMS analysis for 90 minutes. It was discovered later that the 480 V main breaker was tripped two hours before the event occurred by an unknown reason. After the 480 V main breaker tripped, the load was carried on the UPS system. The UPS system depleted within two hours, triggering a switchover to an alternate source.

When the alternate source was activated, the servers lost power due to the redundant power supplies in the racks not being connected to the alternate power source, causing the RTU failures. An alarm was sent to the building facilities regarding the power supply failure; however, the facilities thought it was a false alarm as they thought it was due to the UPS card, and hence did not notify the control center.

Case 5:

An entity's network traffic was interrupted between the primary control center and the rest of the network. The entity has redundant systems and network equipment; however, the primary and redundant firewall switches that link the primary control center to the rest to the network were connected to the same ATS in the same rack. An overcurrent event caused circuit breakers to open on power distribution units (PDUs) that feed electricity from a UPS to the single ATS. As a result, both firewall switches were de-energized.

Case 6:

There was scheduled maintenance on the UPS system to increase the electrical capacity of the control room. When the load was switched from the "B" side PDU to the "A" side PDU, it caused a breaker to trip

within one of the EMS racks that contained a set of core EMS servers. It was discovered that the PDU overloaded the breaker when all the load was moved to the "A" side to allow working on the "B" side.

Case 7:
The entity experienced loss of Inter-Control Center Communications Protocol (ICCP) connections. The cause of the failure was a loss of power to the control room that was caused by a broken pole that dropped the first circuit into the control center and subsequent line switching issues that dropped the second circuit. The backup generator came on-line, but several systems, including the ICCP connections, were lost due to inrush current upon repowering the devices simultaneously, overloading the breakers for the racks. Power inputs for several devices were connected to the same breaker that had capacity slightly above steady-state requirements. If that breaker gets tripped, those devices lose all power.

Corrective Actions
In each of these cases, upon noticing the degradation of the situational awareness, the entity contacted the appropriate personnel (e.g., RC and operations support staff) to assist with monitoring and help repair the situation.

Case 1:
Facility power was restored when station maintenance personnel initiated a manual override of the ATS, successfully restoring off-site power via the alternate source. The failed 240v regulator was replaced. The standard substation instructions are to be updated to include the expected capacity of the facility UPS battery system with all affected system operating personnel made aware of the revision.

Case 2:
Facilities maintenance manually re-energized individual UPS load centers by physically bypassing the UPS. A separate battery backup was added to the RAD multiplexer power supply in the communications room at the PCC. Substation RTUs are currently connected through multiplexers (MUXs) via serial communications to both RAD multiplexers, one located at the PCC and one at the BCC. The settings for the substation RTUs were modified to allow for continued communication upon the loss of communications path to one of the MUX units. Specifically, the "Automatic Subchannel Disable" function was enabled with a 13.5 second delay on the RADs at the remote RTUs so that communications will restart to the remaining control center RAD Multiplexer upon loss of one channel.

Case 3:
The fuse was replaced. The messages were modified to be audible alarms that require operator acknowledgment.

Case 4:
The building personnel manually switched the servers to the alternate source. The configuration error (the power supplies of the switches were accidentally connected into the same UPS circuit) was corrected.

Case 5:
The circuit breakers were manually closed. The affected ATS was replaced. In addition, an alternate route

will be added to another ATS that will be used for the redundant firewall switches, providing separate power sources between the primary and redundant firewall switches.

Case 6:
The decision was made to fail over to the backup EMS located at the backup control center. The electrical load on the PDUs were distributed to separate breakers within the same PDU.

Case 7:
The following corrective actions have been made:

- Increasing the amp loading capacity of the breaker(s) for the racks that are needed
- Adding additional breakers to the PDU to the racks as needed
- Separating the inputs of the device that were connected to the same breaker
- Redistribute devices to prevent overloading

Lessons Learned

While each of these EMS-related events were slightly different, there were some common themes and lessons learned that can be applied.

- Routines should be created for monthly testing and maintenance running of the backup generator. Test and maintenance operation of a generator should be performed at full load based on the supplier's recommended maintenance routines.
- The necessary UPS battery life, charge cycle, and size should be assessed as part of a risk analysis. The document about the expected capacity of the facility UPS should be up to date.
- Periodic maintenance and monitoring of any UPS system are beneficial. While some UPS systems perform battery maintenance/cycling internally, additional checks and testing may be needed to verify existing bypass capabilities, current loading, and other desired functionality.
- The devices should be balanced between PDUs to prevent overloading. Additional breakers to the PDU are needed when multiple devices are connected to the same breaker.
- It is essential to ensure that the input ratings of the PDU are in harmony with the outlet ratings and that they have the required functions. Intelligent PDUs are recommended because they can monitor the power supply to equipment, unbalanced loading of circuits, power consumption, switching in and out, etc.
- The power supplies of the switches should be connected into the different UPS circuits. The separate routes are needed for the redundant ATS to provide independent power sources between the primary and redundant firewall switches.
- A redundant sealed valve regulated lead acid battery string on each parallel UPS is recommended. In addition to higher reliability, this will allow for more comprehensive testing of each module. The redundant battery string will allow for annual performance testing to include load bank testing and

float voltage testing of a string while it is not in service. The battery strings will also be rotated on a two- to three-month cycle.

- Communication between work groups or departments is vital to maintaining situational awareness of the bulk power system. A procedure should be created and enforced to ensure all work groups/departments (e.g., facility, control room, etc.) are notified of what occurred.
- Mandatory operator response to alarms should be reinforced, including communication requirements. Audible alarms are necessary for operator acknowledgement.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC is asking entities who have taken action on this lesson learned to respond to the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	NERC – Event Analysis (via email)
Source of Lesson Learned:	NERC
Lesson Learned #:	20190801
Date Published:	August 1, 2019
Category:	Communications

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

RAS Unexpected Operation

Primary Interest Groups
Reliability Coordinators (RCs)
Balancing Authorities (BAs)
Transmission Operators (TOPs)
Transmission Owners (TOs)

Problem Statement
An unexpected remedial action scheme (RAS) operation was triggered by an external physical action that initiated a large amount of generation rejection and automatic load shedding as programmed according to the RAS settings.

Details
Before the event, a field technician was in the process of adding points for a new transmission line that was not yet in service to the RAS. In accordance with the work plan, the technician physically removed the control unit that commands the RAS. This isolated the RAS system in order to avoid generation rejection and/or remote load shedding during testing. After completing the test plans, the field technician verified with the operators that no alarms were present prior to restoring the system to normal operation.

Once the system was restored to normal operation, the field technician realized that a label that identifies the functions served by the card in the control unit had not been changed as required. The label is inserted in a plastic panel sleeve that is located on the front of each card. The field technician attempted to make this change by manipulating the plastic panel over the label on the card of the control unit, inadvertently triggering the RAS. This resulted in the RAS rejecting generation and triggering automatic load shedding.

During post event analysis, field technicians were able to reproduce this event by isolating the control unit (so as to not repeat the incident again) and manipulating the plastic panel on this same board.



During the investigation they also noticed that the cards, although seated correctly in the backplane of the unit, were not securely fastened with screws on both the top and bottom of the board as designed.

Therefore, the pressure the technician applied while attempting to change the label jostled the unsecured card, causing loss of contact in the backplane and triggering the necessary outputs to initiate the RAS to reject generation and shed load.

Corrective Actions

The screws that were missing were installed, and inspections were conducted to identify other occurrences where cards may not have been securely fastened.

As a preventive measure, a reminder program has been instituted that aims to ensure that the screws on the top and bottom of all the cards are fastened.

Lesson Learned

During installation/commissioning, care should be taken to ensure that the installation follows supplier design intent and recommendations.

The purpose of the screws was to completely immobilize the cards to prevent intermittent contact issues in the backplane due to physical agitation. Without being secured, bumping the cabinet, vibration from heavy equipment, or an earthquake could possibly trigger a similar reaction.

Procedures should include reminders that equipment parts are provided for a reason and, regardless of how stable an electrical connection is, liberty should not be taken to omit any pieces provided without proper engineering design review.

No matter how simple a change, correction, or labeling of an active RAS may seem, work plan procedures and their review should be detailed and precise to ensure all commissioning steps are completed while the RAS system is isolated.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC is asking entities who have taken action on this lesson learned to respond to the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	NPCC – Event Analysis
Source of Lesson Learned:	Northeast Power Coordinating Council
Lesson Learned #:	20190802
Date Published:	August 1, 2019
Category:	Transmission Facilities

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

NERC
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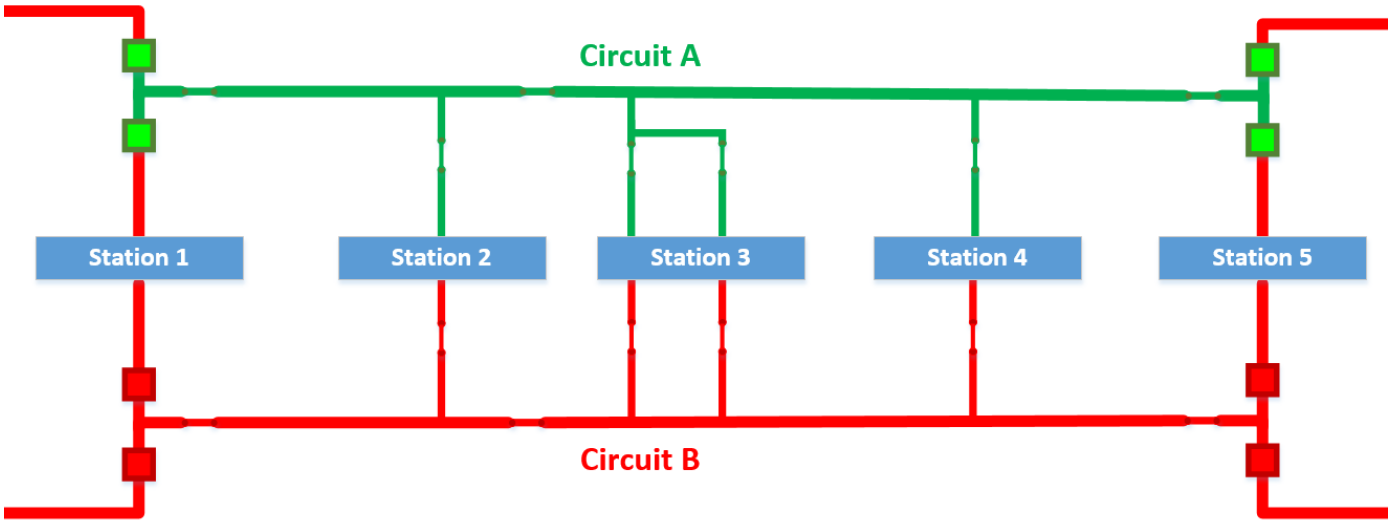
Lesson Learned

Inadvertent CVT Fuse Removal on a Live Circuit

Primary Interest Groups
Transmission Operators (TOPs)
Transmission Owners (TOs)
Generator Operators (GOPs)
Generator Owners (GOs)

Problem Statement
During planned maintenance work on a 230 kV circuit (Circuit A), CVT fuses for a parallel circuit (Circuit B) were inadvertently removed during isolation. The inadvertent removal of the fuses resulted in the subsequent removal of Circuit B from service by line protection operation and a load loss of approximately 382 MW.

Details
On March 25, 2019, Circuit A was required to be removed from service and isolated to facilitate planned maintenance on some high voltage switches. To support this work, remote switching was completed to transfer load from Circuit A to its companion circuit (Circuit B).



Once the load had been transferred and Circuit A was out of service, an isolation sequence was issued to a crew of two station staff for them to execute at Station 1. This involved the removal and tagging of Circuit A fuses to ensure that it was properly isolated from all energy sources.

Contained within the switching job guidance document was a step to “Conduct a familiarization tour of the equipment you will be switching.” The crew did not perform this step even though it was checked off as

completed. The reasoning for not completing the familiarization tour was that the station staff believed that this step is only needed if the switching agent is not familiar with the location or type of equipment being switched. Since this was their primary work location, the agent determined this step was not required. The crew also had to wait for approximately four hours before being formally issued the switching sequence by the controlling authority.



During isolation, station staff inadvertently removed the Circuit B fuses that were physically located beside the Circuit A fuses. The CVT fuse boxes for Circuit A and Circuit B, while correctly labeled, were very similar and differed by a single character.

The removal of the Circuit B fuses resulted in the inadvertent operation of the Circuit B line protection and subsequent load loss of approximately 382 MW. All staff on site were confirmed to be safe before the request to reinstall the fuses to allow the circuit and affected load to be restored. An investigation into the incident was initiated following the event.

Corrective Actions

- The Circuit B fuses were reinstalled to allow the circuit and affected load to be restored.
- The correct isolation sequence was reviewed with the switching staff, and a human performance bulletin was issued to all switching personnel for review and awareness.
- A review of the switching documentation content and training frequency was initiated with the intent of adding procedures and process to detail the roles and responsibilities when two people are used for switching. The possibility of revising the switching process to minimize the delay for field staff between being assigned switching and performing the work will also be explored.
- The possibility of adding locks to CVT cabinets will be explored. This would add an engineering barrier that could help prevent a similar incident from occurring in the future since the proper key would need to be retrieved before the device could be operated. This would provide a similar barrier as seen in other primary equipment devices.

Lesson Learned

- Enhance labeling or color differences between similar nearby or parallel equipment.
- When performing local switching/isolation at a station, ensure that all switching staff take the time to positively identify the equipment being operated with what's required.

- Guard against complacency and overconfidence when conducting work at your primary work location. Do not skip steps in a procedure due to familiarity.
- Never develop a false sense of security just because a second set of eyes (due to two person switching) would be expected to catch an error.
- Make clear training or documentation which details what the roles and responsibilities are for each person when there are two people performing switching (repeating back orders, etc.)
- Be cognizant of the possible effect of long wait times and proximity to lunch and break times when issuing switching sequences as this could lead to a loss of focus.
- Do not rely primarily on switching training being derived from on-the-job experience from working with qualified staff at the field locations. This practice will most likely lead to inconsistencies in the switching process.
- Set a specific duration of time when refresher courses of formal training must be completed.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC is asking entities who have taken action on this lesson learned to respond to the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	NPCC – Event Analysis
Source of Lesson Learned:	Northeast Power Coordinating Council
Lesson Learned #:	20190803
Date Published:	August 1, 2019
Category:	Transmission Facilities

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

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

2020 Business Plan and Budget Preparation Schedule

2019 DATES	NERC	NPCC
January – March	Seek input from staff on business plan and budget requirements – Final assumptions to be received from NERC by early January	
February 6-7	NERC BOT and FAC Meetings – quarterly (Q1) meeting includes review of 2018 unaudited results for NERC, the Regional Entities and consolidated ERO Enterprise	
February 19	EROFG Conference Call	
February 21		NPCC FAC to review preliminary 2020 Business Plan & Budget Scenarios and endorse scenario to bring to full BOD
March 1		Make initial request for previous year NEL data
March 8		Send 2020 budget templates to AVPs to update and set meetings to discuss
March 20		NPCC BOD Meeting – present FAC endorsed 2020 BP&B Scenario
March 20	EROFG Conference Call	
March 22		Due date for AVPs to provide 2020 budget projections and draft of budget verbiage for each program area
March 26		NPCC FAC to review 2018 audited FS and BOD comments on 2020 BPB scenario
April 6	RE's resources pie chart estimated data to NERC	
April 16		Distribute Draft 1 2020 Business Plan & Budget to NPCC FAC for April 23 meeting
April 20		**Q1 RE variance report due to NERC**
April 23		NPCC FAC Teleconference – Draft 1 2020 Business Plan & Budget
April 24		Include Draft 1 2020 BP&B in 2nd mail out for May 1 BOD meeting
April 25	EROFG Conference Call	
April 26		**Draft 1 of RE Business Plans and Budgets due to NERC – NPCC will submit on May 1**

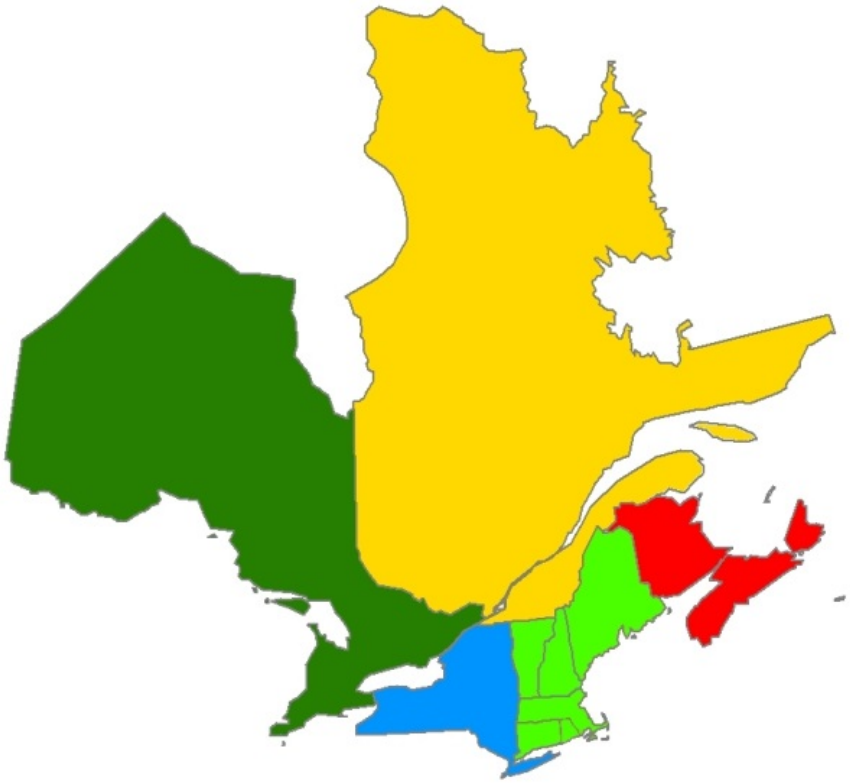
2019 DATES	NERC	NPCC
May 1		**2018 Budget to Actual True-Up files due to NERC**
May 1		**NPCC BOD Meeting – present Draft 1 2020 Business Plan & Budget**
May 1		**Post Draft 1 2020 BP&B to NPCC website for comment through May 31**
May 8-9	NERC FAC Meeting- review of year-end financial statements	
May 8-9	MRC Meeting-Presentation of Draft NERC BP&B and ERO consolidated BP&B presented by NERC management	
May 10	RE Presentations to FERC and NERC FAC slides due to NERC	
May 16 (if needed)		Distribute Draft 1 BP&B to NPCC FAC w/ comments received to date for May 24 meeting
May 17	Draft 1 of NERC Business Plan and Budget posted on NERC website	Draft 1 of RE Business Plans and Budgets posted on NERC website
May TBD	**NERC and REs present draft Business Plan and Budgets to FERC staff in DC**	
May 30	NERC and Regional Entity 2018 budget to actual true-up filing due to FERC	
May 30	**NERC Finance and Audit Committee and management conference call and webinar to review 1st draft of NERC, Regional Entity and ERO Enterprise 2020 NERC BP&Bs**	
May 23 (if needed)		NPCC FAC Teleconference – review Draft BP&B comments received (if needed)
May 29		**Present Draft 1 NPCC BP&B at RCC meeting**
May 30	**NERC Finance and Audit Committee and management conference call and webinar to review 1st draft of NERC, Regional Entity and ERO Enterprise 2020 NERC BP&Bs**	
June 5		**NPCC BOD Meeting – present Update on Draft BP&B** (present comments and changes - if any material changes)
June 17		NPCC FAC Teleconference – endorse Draft for Approval 2020 BP&B
June 17	EROFG Conference Call	
June 19		**Distribute Draft for Approval 2020 BP&B to NPCC BOD in 2nd mailout for June 26th Meeting**
June 26		**NPCC BOD Meeting - Approval of 2020 BP&B**

2019 DATES	NERC	NPCC
July 2	NERC management meets with MRC BP&B input group and Trades to discuss comments received on draft NERC draft BP&B and obtain informal input (conference call established to allow other MRC members and stakeholders to participate)	
July 9		**Final Regional Entity 2020 budget submittal due to NERC (approved by Regional Entity Boards) together with final list of LSEs and NEL data**
July 12	NERC posts final NERC draft 2020 BP&B, final Regional Entity 2020 BP&Bs and consolidated ERO Enterprise 2020 BP&B	
July 16	EROFG Conference Call	
July 18	FAC webinar to review final of NERC BP&B and final RE budget submittals	**RE's present final 2020 BP&Bs to NERC FAC**
July 20		Q2 RE variance report due to NERC
July 27	Comments due on final draft of 2020 NERC BP&B	
July TBD	EROFG presents Final 2020 BP&Bs to FERC via teleconference	
August 7	Final NERC and RE business plans, budgets and assessments posted for NERC FAC, Board of Trustees and Member Representatives Committee	
August 9	NERC FAC Meeting to review and recommend approval of NERC and RE final BP&Bs	
August 14-15	NERC and RE business plans, budgets and assessments presented to NERC Board of Trustees for approval	
August 23	Submit package to FERC and Canadian provincial authorities for approval. Package to include: (1) the NERC and RE business plans and budgets approved by the Board of Trustees, (2) NERC's annual funding requirement (including regional entity costs for delegated functions) and (3) the mechanism for assessing charges to recover that annual funding requirement.	

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

Northeast Power Coordinating Council, Inc. (NPCC)

2020 Business Plan and Budget



Draft #1
Submitted to NERC May 1, 2019

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Introduction

Total NPCC Resources (in whole dollars)	2020 Budget	U.S.	Canada	Mexico
Regional Entity Division FTEs	41.09			
Criteria Services Division FTEs	2.16			
Total FTEs	**43.25**			
Regional Entity Division Expenses	$16,431,647			
Criteria Services Division Expenses	$1,118,668			
Total Expenses	**$17,550,315**			
Regional Entity Division Inc(Dec) in Fixed Assets	**$170,000**			
Criteria Services Division Inc(Dec) in Fixed Assets	**$30,000**			
Total Inc(Dec) in Fixed Assets	**$200,000**			
Regional Entity Division Working Capital Requirement**	**($1,019,611)**			
Criteria Services Division Working Capital Requirement***	**($79,265)**			
Total Working Capital Requirement	**($1,098,876)**			
Total Regional Entity Division Funding Requirement	$15,582,037			
Total Criteria Services Division Funding Requirement	$1,069,402			
Total Funding Requirement	**$16,651,439**			
Regional Entity Division Assessments	**$15,338,737**	$XXX,XXX	$XXX,XXX	
Regional Entity Division Assessments Percentage	**100%**	XX.X%	XX.X%	
Criteria Services Division Membership Fees	**$1,065,202**	$XXX,XXX	$XXX,XXX	
Total NPCC Assessments & Membership Fees	**$16,403,939**	$XXX,XXX	$XXX,XXX	
NEL	XX	XX	XX	
NEL %	100%	XX.XX%	XX.XX%	

** Refer to Table B-1 on page 57 in Section B.
*** Refer to the Reserve Analysis on page 74 in Section C.

2020 Overview of Total NPCC Resource Requirements

Due to the international nature of NPCC, the total resource requirements including both Regional Entity division and Criteria Services division are identified above. The individual divisional explanations are contained in subsequent sections.

NPCC proposes to increase its total operating budget and assessments by 2.1% comprising a Regional Entity increase of 2.2% and a Criteria Services division increase of 0.6%. Additional 2020 succession implementation costs will be funded through existing Business Continuity Reserves, having no impact on assessments, and are excluded from the operating budget increase calculation. The proposed 2020 funding requirements will be satisfied by a Regional Entity division assessment of $15,338,737 and Criteria Services division fees of $1,065,202, for a total of $16,403,939. The total NPCC assessments and fees represent an increase of 2.1% compared to the 2019 total assessments and fees of $16,062,277. NPCC believes that the Region remains an effective provider of Regional Entity and Criteria Services division functions. NPCC's corporate culture centers on consistent delivery of excellent results at a cost that is considerate of the longstanding tradition in the Northeast of affordable and reliable electricity.

Organizational Overview

Northeast Power Coordinating Council, Inc. (NPCC) is a 501(c)(6) not-for-profit corporation in the state of New York responsible for promoting and improving the reliability of the international, interconnected bulk power systems in Northeastern North America through (i) the development of Regional Reliability Standards and compliance assessment and enforcement of continent-wide and Regional Reliability Standards, coordination of system planning, design and

operations, and assessment of reliability (collectively, Regional Entity activities), and (ii) the establishment of Regionally-specific criteria, and monitoring and enforcement of compliance with such criteria (collectively, Criteria Services activities). NPCC provides the functions and services for Northeastern North America of a cross-border Regional Entity through a Regional Entity division, as well as Regionally-specific Criteria Services for Northeastern North America through a Criteria Services division. NPCC's website is www.npcc.org.

The NPCC Region covers nearly 1.2 million square miles and is populated by more than 56 million people. NPCC U.S. includes the six New England states and the state of New York. NPCC Canada includes the provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. In total, from a net energy for load perspective, NPCC is approximately 46% U.S. and 54% Canadian. With regard to Canada, approximately 70% of Canadian net energy for load is within the NPCC Region.

Effective January 1, 2016, NPCC executed an Amended and Restated Regional Delegation Agreement with the North American Electric Reliability Corporation (NERC) that delegates to NPCC certain responsibilities and authorities of a cross-border Regional Entity as defined by *Section 215* of the Federal Power Act in the U.S. In addition, NPCC has executed Memoranda of Understanding or Agreements with Canadian provincial regulatory and/or governmental authorities in Ontario, Québec, New Brunswick and Nova Scotia.

It is imperative that NPCC maintain its ability to carry out delegated authorities and responsibilities. NPCC has a 2020 targeted staffing level of 43.25 power industry professionals and support personnel. Details of the 2020 business plans and budget for each program area are included in Section A for the Regional Entity division. The 2020 Regional Entity division schedules are shown in Section B. Section C details the 2020 Criteria Services division business plan and budget.

Membership and Governance

NPCC monitors approximately 215 registered entities and some 448 functions in the Region for compliance with mandatory Reliability Standards. NPCC currently has approximately 80 members. There are two categories of membership, General and Full. The two categories distinguish between Regional Entity delegated services that are provided in support of the U.S. FERC and Canadian provincial MOUs or Agreements with regulatory and/or governmental authorities, and Criteria Services which FERC references as U.S. non-delegated activities.

General Membership is voluntary and is open to any person or entity, including any entity participating in the Registered Ballot Body of the Electric Reliability Organization (ERO) that has an interest in the reliable operation of the Northeastern North American bulk power system. General Members which are also registered entities within the NPCC Region are subject to compliance with Reliability Standards, consistent with their registration, and also receive additional services from the Regional Entity division of NPCC.

Full Membership is available to Members which are already General Members and participate in electricity markets in the Northeast. Independent system operators (ISOs), Regional transmission organizations (RTOs), Transcos and other organizations or entities that perform the Balancing Authority function operating in Northeastern North America are expected to be Full Members of NPCC. The New York State Reliability Council and any other sub-regional reliability councils which may be formed are also expected to be Full Members. Full Members are subject to compliance with Regionally-specific more stringent reliability criteria for their

generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area and which are identified utilizing a reliability impact-based methodology, in addition to Reliability Standards, and receive additional services from the Criteria Services division of NPCC, which is not funded through the ERO.

Under the Criteria Services division, NPCC will seek out and evaluate for membership, entities involved in emerging technologies to assure that those entities that have an impact on Bulk Electric System reliability are included in appropriate NPCC activities.

Since January 1, 2012 NPCC is governed by a Board of Directors consisting of seven stakeholder voting sectors consisting of a maximum of two directors per sector, an independent sector consisting of two independent directors, an independent Board Chair with voting rights to preclude board deadlocks, and the President and CEO. Within NPCC, no two sectors can control and no one sector can block action. The voting sectors on the NPCC Board of Directors include:

Sector 1) Transmission Owners
Sector 2) Reliability Coordinators
Sector 3) Transmission Dependent Utilities, Distribution Companies, Load Serving Entities
Sector 4) Generator Owners
Sector 5) Marketers, Brokers and Aggregators
Sector 6) Regulators
Sector 7) Sub-Regional Reliability Councils, Customers, other Regional Entities and Interested Entities
Sector 8) Independent

A Finance and Audit Committee (FAC), a Pension Committee (PC), a Corporate Governance and Nominating Committee (CGNC), and a Management Development and Compensation Committee (MDCC) advise the Board on finance, governance, compensation and human resource matters consistent with their approved charters. The Board endorses a non-employee, Certified Public Accountant for election by the NPCC Members as Treasurer of the corporation. The Treasurer chairs the FAC and works with the Chief Operating Officer who provides oversight of the finances of the corporation. The Treasurer reports to the Board on the corporation's financial position, on FAC activities, on tax code requirements, and on independent annual audit results and accounting practices.

The Regional Standards Committee (RSC), the Compliance Committee (CC), the Reliability Coordinating Committee (RCC), and the Public Information Committee, consistent with their approved scopes, are responsible for various reliability issues. The RSC, CC and RCC also provide technical policy recommendations to the Board. All General and Full Members are eligible for representation on the technical committees.

Industry technical experts from within the membership provide valuable input to the Board through various working groups and task forces as well as the committees. The *Amended and Restated Bylaws* establish NPCC's independence from users, owners and operators of the bulk power system through the enhanced governance structure while providing fair stakeholder representation in the election of the Board of Directors and officers. The members, from each of the seven stakeholder voting sectors, vote to elect directors in their respective sector. The *Amended and Restated Bylaws* establish criteria for board service for both stakeholder and independent directors. Independent Directors are drawn from diverse backgrounds and possess a

broad range of industry expertise, perspectives, experiences, skill sets and knowledge to contribute to the effective functioning of a hybrid board structure.

Compliance and enforcement activities are carried out by the NPCC compliance staff and are independent of all users, owners and operators of the international bulk electric system. Compliance activities are governed in the United States by the *Amended and Restated Regional Delegation Agreement* between NERC and NPCC, delegating portions of NERC's authority as the ERO to NPCC. NPCC compliance activities in Canada are governed by individual provincial Memorandum of Understanding (MOU) or Agreements with each province providing the unique parameters for compliance and enforcement activities for each of the provinces. An MOU between the Independent Electricity System Operator in Ontario (IESO), NERC and NPCC establishes roles and responsibilities with regard to that province. NPCC, NERC and the New Brunswick Energy and Utilities Board are parties to a MOU that sets forth reliability activities for New Brunswick. The Régie de l'énergie, NERC and NPCC executed an Agreement regarding the implementation of the Québec reliability standards compliance monitoring and enforcement program. NPCC, NERC and Nova Scotia executed a MOU that sets forth the mutual understanding of the parties in relation to the approval and implementation of NERC Reliability Standards and NPCC Regional reliability criteria for the province of Nova Scotia.

International Foundation

The Regional Entity functions and services differ according to particular regulatory backstop:

a) U.S. Foundation

The Federal Energy Regulatory Commission (FERC) certified NERC as the Electric Reliability Organization (ERO) on July 20, 2006. The ERO is responsible for developing and enforcing reliability standards within the United States. In executing part of its responsibilities, NERC delegates authority to the Regional Entities to perform certain functions through delegation agreements. Ensuring the reliability of the bulk power system in the State of New York and the six New England States was delegated from NERC to NPCC through the *Amended and Restated Regional Delegation Agreement*.

b) Ontario

On February 5, 2010, NERC, NPCC and the IESO amended and restated their earlier MOU, dated November 29, 2006, setting forth their mutual understanding as regards NERC's and NPCC's status in Ontario with respect to standard and criteria development, compliance enforcement, and other related matters. The IESO, whose statutory responsibilities include making and enforcing reliability standards, and making and enforcing Ontario market rules that govern the IESO-controlled grid and the wholesale electricity market, was established April 1, 1999 as the Independent Electricity Market Operator in Ontario under the *Electricity Act, 1998* (Ontario). The IESO is subject to the regulatory oversight of the Ontario Energy Board (OEB).

Among other things, the MOU recognizes that NERC and NPCC are standards authorities under the *Electricity Act, 1998* (Ontario). Additionally, under the authority of that same legislation, and as memorialized in the MOU, the NERC reliability standards and NPCC reliability criteria have effect in Ontario. However, a 2008 amendment to the Electricity Act, 1998 (Ontario) allows the OEB to review these standards and criteria and issue orders preventing their implementation and remanding them back to NERC and NPCC.

The IESO is subject to compliance monitoring and enforcement by NPCC. The IESO is also subject to compliance monitoring and enforcement of the Ontario market rules by the IESO's

Market Assessment and Compliance Division (MACD) that operates at arm's length from the IESO's business units. The MOU notes that where MACD, NERC, and NPCC engage in investigations pursuant to their respective mandates regarding compliance, MACD can request to take the lead. Moreover, of the three, MACD is the only entity that can assess financial penalties for any Ontario market participant's or the IESO's non-compliance with Ontario market rules, which includes non-compliance with NERC standards and NPCC criteria.

The MOU provides for a peer review process to promote the common compliance and enforcement objectives of NERC/NPCC and MACD. From the perspective of NPCC and NERC, this process, in part, is meant to assure registered entities outside of Ontario that the MACD program is rigorous, thorough and reliable.

The IESO is subject to NPCC assessments of compliance, including audits, as well as NPCC remedial action directives to correct non-compliance. In the event that the IESO disagrees with NPCC's finding of a violation or associated assessment of sanctions in connection with standards and criteria, the IESO has a right to a compliance hearing with NPCC.

c) Québec

The Régie de l'énergie, NERC and NPCC are parties to the May 8, 2009 *Agreement on the Development of Electric Power Transmission Reliability Standards and of Procedures and a Program for the Monitoring of the Application of These Standards for Québec* (the 2009 Agreement). Under the terms of the 2009 Agreement, the Régie de l'énergie , which is charged with ensuring the reliability of the electric transmission in Québec, retained NPCC and NERC as experts to develop reliability standards and monitoring program procedures for the Province.

The Régie de l'énergie, NERC and NPCC are parties to the September 24, 2014 *Agreement on the Implementation of the Québec Reliability Standards Compliance Monitoring and Enforcement Program* (the 2014 Agreement). Through the 2014 Agreement, the Régie de l'énergie retains the services of NPCC to monitor and assess the compliance of registered entities in Québec with the reliability standards adopted by the Régie with respect to electric power transmission in Québec.

On April 1, 2015, the Québec Reliability Standards Compliance Monitoring and Enforcement Program ("QCMEP"), which was developed jointly by the Régie de l'énergie, NPCC and NERC, came into effect. Together, the 2014 Agreement and the QCMEP detail the procedures and program for monitoring and enforcing mandatory electric power transmission reliability standards in Québec.

The Régie de l'énergie is a public body established by the *Act respecting the Régie de l'énergie* (the Act). Pursuant to its authority under the Act, the Régie de l'énergie, through a series of decisions in 2007, designated Hydro-Québec Contrôle des mouvements d'énergie (HQCMÉ), a division of Hydro-Québec TransÉnergie, as the Reliability Coordinator for Québec. In accordance with its mandate and as recognized in the 2009 Agreement, it is this entity that is responsible for the filing with the Régie de l'énergie for approval of reliability standards in Québec. HQCMÉ has filed for the approval of certain reliability standards and the Régie de l'énergie has made certain reliability standards mandatory in Québec and is continuing proceedings to make additional reliability standards mandatory in Québec.

NPCC also conducts reliability assurance activities within Québec, including but not limited to events analysis, Reliability Assessment and Performance Analysis and compliance investigations, consistent with the NPCC *Amended and Restated Bylaws*.

d) New Brunswick

On October 1, 2013, the Electricity Act (NB) and implementing regulations (together, "NB Electricity Act") amended how Reliability Standards are approved, monitored, and enforced in the province of New Brunswick. The NB Electricity Act designates NPCC as a compliance body and NERC as a standards body within the meaning of the NB Electricity Act. The New Brunswick Energy and Utilities Board (NBEUB) is an independent, quasi-judicial board that is responsible for regulating New Brunswick's electricity sector under the NB Electricity Act. The NBEUB has the responsibility to adopt and enforce reliability standards in New Brunswick.

As contemplated in the NB Electricity Act, NPCC and the NBEUB entered into a Service Contract dated August 10, 2016, whereby NPCC provides CMEP and other services for the NBEUB. Additionally, the NBEUB, NPCC, and NERC entered into a Memorandum of Understanding on August 10, 2016, which describes the roles and responsibilities of the three entities and facilitates data sharing. These two documents, along with the NB Electricity Act are the governing documents with respect to conducting CMEP and other reliability related activities in New Brunswick.

With respect to the approval of reliability standards, the NB Electricity Act provides that all of the NERC Reliability Standards that were effective in New Brunswick prior to October 1, 2013 continue to be effective in New Brunswick after October 1, 2013. Additionally, the NB Power is required to file for approval, modification, or retirement of NERC Reliability Standards 60 days after a NERC Reliability Standard is approved, modified, or retired by the FERC. The NBEUB rules on the filed Reliability Standard after considering (a) the potential impact on the reliability of the bulk power system, (b) the potential cost and benefits (c) the public interest, and (d) any other factors that the NBUEB considers relevant. The Electricity Act requires the NBEUB to notify NPCC and NERC of an application by NB Power with respect to reliability standards and provide for a 60 day comment period. The NBEUB is required to approve the reliability standards if there are not substantive modifications proposed from the FERC approved NERC Reliability Standard and there were no substantive comments filed. Amendments to the reliability standard to make them compatible with New Brunswick or Canadian law are considered non-substantive. The approval of reliability standards may be subject to a hearing for several reasons, including substantive comments from NPCC or NERC.

With respect to the monitoring and enforcement of the Reliability Standards in New Brunswick, the NB Electricity Act provides for NPCC to identify entities that must register with the NBEUB in the New Brunswick specific registry. Additionally, NPCC may carry out the compliance monitoring and assessment for the NBEUB and assist and advise the enforcement for the NBEUB, including financial penalties. NPCC is also permitted to carry out or exercise any power in the implementing regulations that is specific to the NBEUB, as provided for in the Service Contract. Additionally, NPCC has the powers of an inspector, which permits NPCC to audit and spot check entities within New Brunswick.

e) Nova Scotia

Nova Scotia Power Incorporated (NSPI), NPCC and NERC are parties to a May 11, 2010 Memorandum of Understanding regarding the approval and implementation of mandatory NERC reliability standards and NPCC Regional reliability criteria. Pursuant to the MOU's terms,

NERC and NPCC filed standards and criteria with the Nova Scotia Utility and Review Board (NSUARB) for approval on June 30, 2010 and June 29, 2010, respectively. A decision from the NSUARB on both NERC and NPCC filings was rendered on July 20, 2011. Hence, the standards and criteria are mandatory in Nova Scotia and NSPI will be subject to the NERC compliance monitoring and enforcement program, as implemented by NPCC.

NPCC will conduct compliance and enforcement activities with respect to the standards and forward any non-compliance information and recommendations to the NSUARB. The NSUARB maintains the final authority with respect to enforcement in Nova Scotia and based on the recommendations from NPCC, may determine whether a violation has occurred and, if so, what remedial measures or non-monetary penalties should be imposed.

2020 Key Goals and Key Deliverables

NERC and the Regional Entities collaborated in the development of a common operating model with complementary roles and responsibilities, an ERO Enterprise Long-term Strategy and an ERO Enterprise Operating Plan. Links to these documents, which incorporated risks identified by the Reliability Issues Steering Committee, are included in the NERC 2020 Business Plan and Budget and may be referenced by the users of this document.

NPCC activities that support ERO Enterprise Goals are detailed in each of the following program area sections. For example, key goals and deliverables within the Reliability Standards program area include supporting the development of risk-responsive Reliability Standards as well as facilitating a Distributed Energy Resources (DER) Forum. Within the Compliance Monitoring and Enforcement and Organization Registration and Certification program, in addition to conducting objective, risk-informed compliance monitoring, enforcement and entity registration activities, this area will be addressing increased enforcement activities and implementing the ERO Enterprise CMEP IT tool (Align). The Reliability Assessment and Performance Analysis program will be focusing on reduction of known risks to reliability and the identification and assessment of emerging reliability risks, such as changing resource composition. In the Situation Awareness and Infrastructure Security area there is an increasing focus on the identification and reduction of cyber and physical security risks through expanded outreach. In an order to achieve these goals and expanded efforts, while minimizing increases in budget, significant reprioritization within the business plan and reallocation of resources were required.

Regional Entity Division Functional Scope

NPCC's Regional Entity division functions in support of the ERO include:

- Active participation in the development of North American Reliability Standards for the bulk electric system, and as needed development of Reliability Standards applicable within the NPCC cross-border Regional Entity.
- Monitoring and enforcement of approved Reliability Standards, including the registration of responsible entities, and as needed certification of such entities.
- Assessment of the present and future reliability of the bulk power system.
- Operational coordination and situation awareness support.
- Event analysis and identifying lessons learned to improve reliability.
- Effective training and education of reliability personnel.
- Promoting the protection of critical bulk electric infrastructure.

In recognition of the delegated compliance role of Regional Entities as an important means to enhancing reliability, NPCC has designated a significant percentage of its staff resources to

compliance monitoring and enforcement. NPCC, in conjunction with NERC and the other Regional Entities, has developed and deployed an ERO Enterprise-wide Compliance Monitoring and Enforcement IT tool (Align) for gathering data, analysis, and tracking of compliance information to carry out these responsibilities in a consistent and cost effective manner.

NPCC has organized the remaining staff into program areas consistent with EPAct 2005 to address the other functions listed above. These experts in operations, planning and reliability analysis assist registered entities in assessing and improving reliability. It is in support of these areas that NPCC engages the majority of industry experts on its technical committees.

2020 Overview of Regional Entity Division Cost Impacts

The proposed Regional Entity division assessment of $15,338,737, to support the Regional Entity division operating budget of $16,157,107, is an increase of 2.2% compared to the 2019 assessment of $15,003,411.

2019 Projections

Current year projections are taken into consideration in development of the budget. Expenses are currently projected to be on budget in all areas or slightly under budget. 2019 Projections reflect expectations based on the first quarter variance report. It is anticipated that projections could change throughout 2019 and would be reflected in each subsequent quarter's variance report.

Statement of Activities Format

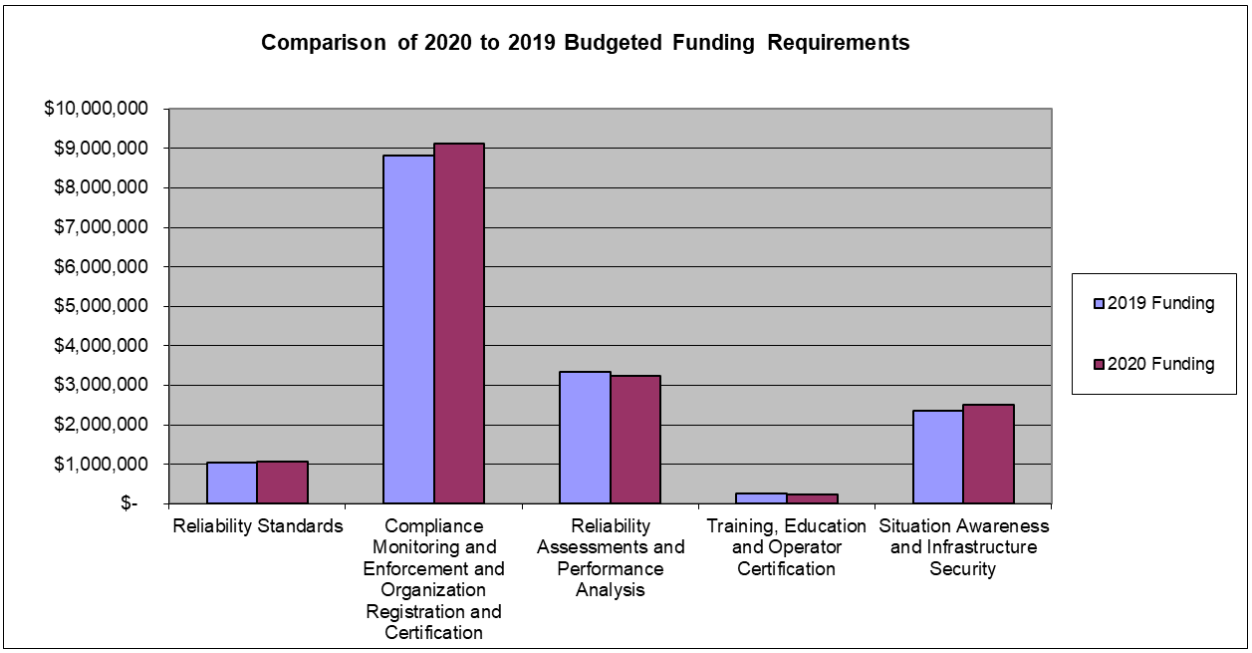
Beginning with the 2020 Business Plan & Budget (BP&B), NERC and the Regions are implementing format revisions to the Statement of Activities report. These revisions are intended to ensure that NERC and the Regions report information consistently from new accounting standards (e.g., leasing standards and right-of-use assets), provide enhanced transparency of financing activity (e.g., debt borrowing, leased-financed asset purchases, and principal payments), and streamline sections of the report related to non-cash expenses (primarily depreciation and amortization). The goal of the new format is to improve the effectiveness of the report to the reader and to provide a total budget amount that more closely reflects the amount of annual revenues required from assessments and other funding sources. One of the format revisions is that the Statements of Activities will no longer show an expense item for depreciation and an equal and offsetting credit for depreciation in fixed asset activity (which resulted in depreciation having no impact on funding requirements or actual results).

In the 2020 BP&B document, the 2019 budget has been restated to reflect the new statement of activities reporting format when comparing 2020 to 2019 to show the year-over-year budget changes on a comparable basis. As such, in the total entity and departmental Statements of Activities, depreciation expense has been removed from the 2019 operating expense budgets and projections, and an equal credit of depreciation expense has been removed from the 2019 fixed asset activity budgets and projections.

Summary by Program

Program	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Reliability Standards	$ 1,035,390	$ 1,035,390	$ 1,071,015	$ 35,625	3.4%
Compliance Monitoring and Enforcement and Organization Registration and Certification	$ 8,816,687	$ 8,671,687	$ 9,109,633	$ 292,946	3.3%
Reliability Assessments and Performance Analysis	$ 3,332,686	$ 3,332,686	$ 3,231,169	$ (101,517)	-3.0%
Training, Education and Operator Certification	$ 252,443	$ 252,443	$ 239,412	$ (13,031)	-5.2%
Situation Awareness and Infrastructure Security	$ 2,366,685	$ 2,366,685	$ 2,505,877	$ 139,192	5.9%
Total	$ 15,803,891	$ 15,658,891	$ 16,157,107	$ 353,216	2.2%

This chart does not include allocation of working capital requirements among the Program Areas.



This chart does not include allocation of working capital requirements among the Program Areas.

Personnel Analysis

Total FTE's by Program Area	Budget 2019	Projection 2019	Direct FTEs 2020 Budget	Shared FTEs[1] 2020 Budget	Total FTEs 2020 Budget	Change from 2019 Budget
REGIONAL ENTITY DIVISION						
Operational Programs						
Reliability Standards	1.93	1.93	1.00	0.93	1.93	0.00
Compliance Monitoring and Enforcement and Organization Registration and Certification	17.00	17.00	18.00	0.00	18.00	1.00
Training, Education, and Operator Certification	0.10	0.10	0.10	0.00	0.10	0.00
Reliability Assessment and Performance Analysis	5.83	5.83	4.50	0.93	5.43	-0.40
Situation Awareness and Infrastructure Security	5.00	5.00	5.40	0.00	5.40	0.40
Total FTEs Operational Programs	**29.86**	**29.86**	**29.00**	**1.86**	**30.86**	**1.00**
Administrative Programs						
Technical Committees and Member Forums	0.50	0.50	0.50	0.00	0.50	0.00
General and Administrative	2.50	2.50	2.50	0.23	2.73	0.23
Information Technology	2.00	2.00	2.00	0.00	2.00	0.00
Legal and Regulatory	1.00	1.00	2.00	0.00	2.00	1.00
Human Resources	1.00	1.00	1.00	0.00	1.00	0.00
Accounting and Finance	2.00	2.00	2.00	0.00	2.00	0.00
Total FTEs Administrative Programs	**9.00**	**9.00**	**10.00**	**0.23**	**10.23**	**1.23**
Total FTEs	**38.86**	**38.86**	**39.00**	**2.09**	**41.09**	**2.23**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

2019 Budget and Projection and 2020 Budget Comparisons

Statement of Activities and Capital Expenditures
2019 Budget & Projection, and 2020 Budget

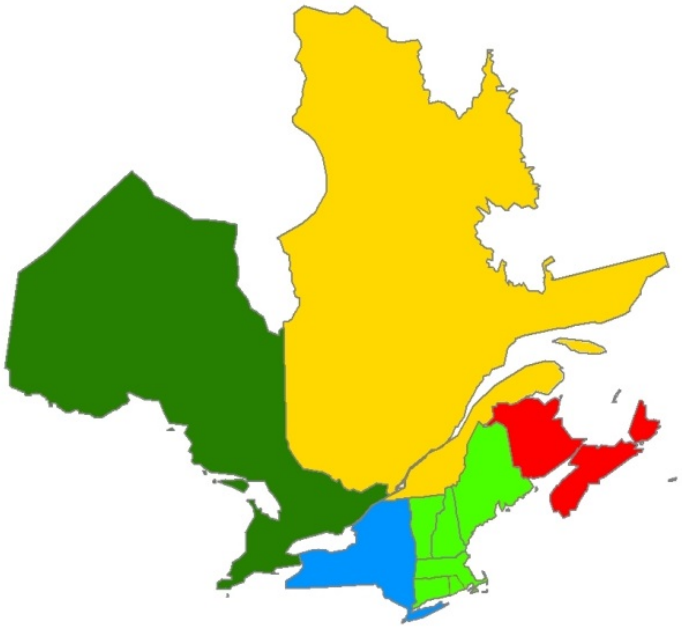
REGIONAL ENTITY DIVISION

		2019 Budget	2019 Projection	Variance[2] 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 15,003,411	$ 15,003,411	$ -	$ 15,338,737	$ 335,326
	Penalty Sanctions[1]	-	-	-	120,000	120,000
Total ERO Funding		**$ 15,003,411**	**$ 15,003,411**	**$ -**	**$ 15,458,737**	**$ 455,326**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	67,500	67,500	-	67,500	-
	Interest & Investment Income	-	-	-	55,800	55,800
Total Funding (A)		**$ 15,070,911**	**$ 15,070,911**	**$ -**	**$ 15,582,037**	**$ 511,126**
Expenses						
Personnel Expenses						
	Salaries	$ 7,332,280	$ 7,216,280	$ (116,000)	$ 7,704,262	$ 371,982
	Payroll Taxes	449,994	444,994	(5,000)	479,019	29,026
	Benefits	1,613,078	1,585,078	(28,000)	1,943,385	330,306
	Retirement Costs	853,511	837,511	(16,000)	882,950	29,440
Total Personnel Expenses		**$ 10,248,862**	**$ 10,083,862**	**$ (165,000)**	**$ 11,009,617**	**$ 760,754**
Meeting Expenses						
	Meetings & Conference Calls	$ 370,750	$ 406,750	$ -	$ 397,750	$ (9,000)
	Travel	845,900	845,900	-	845,900	-
Total Meeting Expenses		**$ 1,252,650**	**$ 1,252,650**	**$ -**	**$ 1,243,650**	**$ (9,000)**
Operating Expenses						
	Consultants & Contracts	$ 2,022,150	$ 2,002,150	$ (20,000)	$ 2,071,150	$ 49,000
	Office Rent	820,700	820,700	-	832,700	12,000
	Office Costs	676,347	676,347	-	685,981	9,634
	Professional Services	978,000	978,000	-	947,000	(31,000)
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	51,000	51,000	-	51,000	-
Total Operating Expenses		**$ 4,548,197**	**$ 4,528,197**	**$ (20,000)**	**$ 4,587,831**	**$ 39,634**
	Total Direct Expenses	**$ 16,049,709**	**$ 15,864,709**	**$ (185,000)**	**$ 16,841,098**	**$ 791,388**
Indirect Expenses		**$ (415,818)**	**$ (415,818)**	**$ -**	**$ (409,450)**	**$ 6,368**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 15,633,891**	**$ 15,448,891**	**$ (185,000)**	**$ 16,431,647**	**$ 797,756**
Change in Assets		**$ (562,980)**	**$ (377,980)**	**$ 185,000**	**$ (849,611)**	**$ (286,630)**
Fixed Asset Additions (C)		**$ 170,000**	**$ 170,000**	**$ -**	**$ 170,000**	**$ -**
TOTAL BUDGET (=B+C)		**$ 15,803,891**	**$ 15,618,891**	**$ (185,000)**	**$ 16,601,647**	**$ 797,756**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (732,980)**	**$ (547,980)**	**$ 185,000**	**$ (1,019,611)**	**$ (286,630)**

[1] $120,000 of penalty sanctions collected to date and prior to June 30, 2019.

[2] 2019 Projections reflect expectations based on the first quarter statement of activities. It is anticipated that projections could change throughout 2019 and would be reflected in each subsequent quarter's statement of activities.

Section A – Regional Entity Division
2020 Business Plan and Budget



Section A — 2020 Regional Entity Division Business Plan and Budget

Reliability Standards Program

Reliability Standards Program Resources (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	1.93	1.93	0.00
Direct Expenses	$665,870	$693,683	$27,813
Indirect Expenses	$359,634	$366,700	$7,066
Other Non-Operating Expenses	$0	$0	$0
Fixed Asset Additions	$10,988	$10,632	($356)
Total Funding Requirement	$1,036,492	$1,071,015	$34,523

Program Scope and Functional Description

The NPCC Reliability Standards Program Area operates in accordance with NPCC's filed and approved Regional Delegation Agreement and NERC Rules of Procedure Section 300. The program supports the ERO Standards Program Area roles and responsibilities, the ERO Enterprise Operating Plan, the ERO Enterprise Long-Term Strategy and aligns with NPCC Board of Director goals and strategies. NPCC's Reliability Standards Program Area provides an efficient and effective mechanism for stakeholders to provide input and facilitate the development of, and improvement to, NERC and Regional reliability standards which are clear, responsive to reliability and security risks, practical to implement, "results based", and are cost effective. The primary objectives of NPCC's Reliability Standards Program Area is to support the development of ERO standards and Regional variances which establish "results-based" requirements for addressing reliability risks with due consideration given to cost effectiveness. NPCC supports the ERO efforts to develop reliability standards in a timely and efficient manner and which are also responsive to FERC Directives and industry risk. NERC and Regional reliability standards must ensure the bulk electric system is planned, operated, and maintained in a manner that minimizes risks of cascading failures, system separation, and instability, and also avoids damage to major equipment, is responsive to risks, or limits interruptions of bulk power supply.

At the Regional level, the standards program area develops, and maintains NPCC Regional Reliability Standards, and ERO Standards Variances for the northeast as required. The NPCC Reliability Standards Program Area also provides oversight to ensure that NPCC's Regional Reliability Criteria contained in the form of Directories, are developed, approved, and maintained as necessary to implement, to augment, or to facilitate compliance with NERC Reliability Standards. NPCC's reliability criteria are not reliability standards but are mandatory and subject to enforcement as outlined in the NPCC *Amended and Restated Bylaws* and various ISO tariffs, and individual interconnection agreements, as well as other executed contractual agreements. Regional Reliability Criteria may also address issues not within NERC's statutory jurisdiction for Reliability Standards, such as resource adequacy, and conform to requirements in Section 313 of the NERC Rules of Procedure.

In addition, the NPCC Reliability Standards Program Area has initiated a Distributed Energy Resources (DER) Forum. As conventional fossil fuel units and nuclear retirements are increasingly being replaced by DER on the transmission system and with grid edge DER on the

distribution system, the reliable operation of the BES as defined in the legislation could be impacted. The control systems of DER introduce new capabilities that could enhance reliability and understanding interoperability issues between transmission and distribution systems will become increasingly important. NPCC is engaged in a number of areas to ensure reliable integration into the BES and opportunities to provide industry guidance for interconnecting DER.

2020 Key Assumptions

- The number of continent-wide Reliability Standards development projects is expected to remain relatively stable, except as required to address any new FERC directives to create or modify Reliability Standards, or industry submittals of standard authorization requests.
- Continent-wide Reliability Standards projects will consist primarily of acting on recommendations of the various phases of the Standards Efficiency Review project, conducting periodic reviews on existing Reliability Standards to improve their content and quality, responding to identified risks to reliability (including those that may be identified through the implementation of risk-based Compliance Monitoring and Enforcement), and addressing FERC directives that may arise. This activity will require the allocation of technical resources from several internal NERC departments (e.g., Reliability Assessment and Performance Analysis (RAPA), Reliability Risk Management, Compliance Analysis and Certification, and Compliance Assurance) and support from across the ERO Enterprise.
- During the periodic review of NERC Reliability Standards, NPCC's Regional Reliability Standard for Underfrequency Load Shedding "UFLS" will be reviewed for potential incorporation as variances or as improvements to the continent-wide requirements. Regional and NERC Reliability Standards development processes may require further modification to efficiently accomplish this task. NPCC will work with NERC and other Regional Entities as necessary on projects where there is a Regional Reliability Standard/variance.
- NPCC's Regional Reliability Standards development activity is expected to remain at a stable level, driven by requests that the Regional Entity may receive or reliability issues that are identified and not under consideration by NERC. Creation of Variances to NERC Reliability Standards to address reliability concerns or to recognize the unique topology and reliability considerations of the Northeast (i.e. Québec's recognition of an asynchronous interconnection within NPCC's footprint) will be performed as necessary.
- The number of NERC and Regional standards interpretations is expected to remain low. Compliance Implementation Guidance documents, which provide approaches to being compliant with NERC Reliability Standards may be developed using NPCC's open process and other industry vetting practices. These guidance documents are currently being developed by industry and the Standard Drafting Teams and the number of requests may increase. The NPCC Reliability Standards program area will assist and facilitate support of these activities.
- Consistent with the NERC Rules of Procedure Sections 312 and 313, as continent wide standards continue to evolve, NPCC Regional Standards and Criteria will need to be continually reviewed to ensure they augment but do not add redundancy to the ERO standards.

2020 Goals and Key Deliverables

- Participate in the annual development and revision of the NERC's three year Reliability Standards Development Plan (RSDP) through review, commenting, and other RSC activities.
- Participate in the NERC Standards Committee, as a representative of the NERC Regional Entities and NPCC Regional stakeholders to advance strategic initiatives, to measure the effectiveness and quality of standards, support ERO efforts to address outstanding FERC Directives, and provide input in the prioritization of standards development projects.
- Support further development of cost effectiveness principles processes and pilots. Continue to provide insights to NERC, based on NPCC experiences, regarding strategy for developing cost effectiveness analysis for standards and identify opportunities to identify cost of risk mitigation for the draft standards.
- Participate in the NERC Standards Efficiency Review Project future phases and resulting activities.
- Participate in the development of ERO Reliability Standards specified in NERC's three-year Reliability Standards Development Plan with the emphasis placed on reducing the amount of new FERC Directives issues by closer coordination with the Commission staff.
- Conduct thorough reviews of all NERC standards under development or revision by leveraging existing NPCC Task Forces and subject matter experts and coordinate NPCC comments for Northeastern North America.
- Participate in the Enhanced Periodic Review Standing Team's grading efforts and coordinate and represent the Regional and interregional input.
- Assist NERC's review of all industry "Requests for Interpretations" of NERC Reliability Standards.
- NPCC staff and Regional drafting team volunteers will participate in the drafting of ERO standards and provide support for development of improvements to standards. Those chosen to participate in drafting of standards will provide a point of contact for the NPCC Regional input to the standard being developed.
- NPCC and its members will review and coordinate comments on FERC staff informal assessments of the ERO Enterprise as appropriate.
- Participate in pre-ballot reviews of ERO standards and coordinate the development of consensus recommendations of the NPCC Members to the NERC Standards Drafting Team (SDT) and provide a list of any unaddressed issues to allow the Members to cast a ballot based on regional concerns to enhance the efficiency of the ERO standards development projects.
- Review and identify issues and concerns raised in FERC NOPRs and NOIs for any and all standards related issues as appropriate.
- Educate and notify stakeholders and regulators about issues related to standards development through various means such as webinars and workshops.
- Provide outreach to industry trade groups such as the North American Generator Forum and North American Transmission Forum when requested.
- Monitor the NERC Reliability Issues Steering Committee "RISC" activities as they identify emerging risks and develop recommended actions to mitigate such risks. Provide a Regional point of contact for all potential reliability related risks and gaps within the Northeast or as noted by NPCC's stakeholders.
- Participate in and provide support to critical standards projects, such as CIP Supply Chain, Facility Ratings (IROL and SOL development), Geomagnetic Disturbances, High

Altitude Electromagnetic Pulse (HEMP), changes to standards driven by inverter based DERs, etc.

- Identify opportunities and initiate Regional Variances to the NERC Reliability Standards as soon as possible, allowing incorporation into the continent wide standard during the development process.
- Conduct reviews of Regional Standards as necessitated by the revision and approval of any associated Continent-wide NERC reliability standards or further reliability related need.
- Conduct the development of any Québec Interconnection-Wide variances to NERC continent-wide standards using the NPCC Reliability Standards Development Process.
- Identify potential reliability benefits and impacts to the BES as a result of DER penetration.
- Conduct ongoing DER Forum activities to solicit and identify both opportunities and challenges to enhancing reliability through education, promotion of awareness and developing guidance, particularly for interconnection of utility scale DER on the Distribution System.
- Identify opportunities to improve resilience of the BES.
- Identify and coordinate reliability related issues with local governmental authorities where jurisdictional issues may exist.
- Ensure the topics addressed by the Reliability Standards align with changing industry and reliability objectives.
- Participate in reliability metrics developmental activities to identify potential measures for benchmarking of reliability and standards to determine if an adequate level of reliability is being achieved through the Enhanced Periodic Review Standing Review Team activities.
- Identify opportunities and processes for cost-effectiveness analysis activities to determine the need to revise a standard during the Periodic Review or Standards Grading efforts.
- Identify any emerging interconnection-wide reliability issues which may need standards solutions and forward to the NERC Reliability Issues Steering Committee for their consideration.
- Identify opportunities to increase reliability or mitigate emerging risk through the revision of standards and their associated requirements.
- Identify any North American Electric Standards Review Board (NAESB) activities which may impact ERO standards.
- Identify potential market related issues for Regional Standards through NPCC RSC coordination and reviews.
- Participate in NPCC Compliance and Standards Workshops and any NERC workshops and webinars to promote industry awareness.

Based on the portion of professional/technical staff time and other resources devoted to Reliability Standards development, NPCC estimates that it will expend approximately 7% of its resources on this activity.

Resource Requirements

- No significant changes.

Reliability Standards Program

Funding sources and related expenses for the Reliability Standards section of the 2019 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures 2019 Budget & Projection, and 2020 Budget						
Reliability Standards						
		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 1,035,390	$ 1,035,390	$ -	$ 1,063,510	$ 28,120
	Penalty Sanctions	-	-	-	7,505	7,505
Total ERO Funding		**$ 1,035,390**	**$ 1,035,390**	**$ -**	**$ 1,071,015**	**$ 35,625**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 1,035,390**	**$ 1,035,390**	**$ -**	**$ 1,071,015**	**$ 35,625**
Expenses						
Personnel Expenses						
	Salaries	$ 382,872	$ 382,872	$ -	$ 400,744	$ 17,872
	Payroll Taxes	22,735	22,735	-	23,034	298
	Benefits	106,764	106,764	-	110,172	3,408
	Retirement Costs	41,599	41,599	-	43,833	2,234
Total Personnel Expenses		**$ 553,970**	**$ 553,970**	**$ -**	**$ 577,783**	**$ 23,813**
Meeting Expenses						
	Meetings & Conference Calls	$ 7,000	$ 7,000	$ -	$ 5,000	$ (2,000)
	Travel	94,900	94,900	-	90,900	(4,000)
Total Meeting Expenses		**$ 101,900**	**$ 101,900**	**$ -**	**$ 95,900**	**$ (6,000)**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 10,000	$ 10,000	$ -	$ 20,000	$ 10,000
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ 10,000**	**$ 10,000**	**$ -**	**$ 20,000**	**$ 10,000**
	Total Direct Expenses	**$ 665,870**	**$ 665,870**	**$ -**	**$ 693,683**	**$ 27,813**
Indirect Expenses		**$ 375,014**	**$ 375,014**	**$ -**	**$ 366,700**	**$ (8,313)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,040,884**	**$ 1,040,884**	**$ -**	**$ 1,060,383**	**$ 19,499**
Change in Assets		**$ (5,494)**	**$ (5,494)**	**$ -**	**$ 10,632**	**$ 16,126**
Fixed Asset Additions (C)		**(5,494)**	**(5,494)**	**-**	**10,632**	**16,126**
TOTAL BUDGET (=B+C)		**$ 1,035,390**	**$ 1,035,390**	**$ -**	**$ 1,071,015**	**$ 35,625**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (0)**	**$ (0)**	**$ -**	**$ 0**	**$ 0**

Compliance Monitoring and Enforcement and Organization Registration and Certification Program

Compliance Monitoring and Enforcement and Organization Registration and Certification Program Resources (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	17.00	18.00	1.00
Direct Expenses	$5,561,849	$5,590,473	$28,624
Indirect Expenses	$3,167,761	$3,420,003	$252,241
Other Non-Operating Expenses	$0	$0	$0
Fixed Asset Additions	$96,785	$99,157	$2,372
Total Funding Requirement	$8,826,396	$9,109,633	$283,237

Program Scope and Functional Description

The NPCC Compliance Monitoring and Enforcement and Organization Registration and Certification Program (CORC) Program Area operates in accordance with NPCC's filed and approved Regional Delegation Agreement, the NERC Rules of Procedure, and individual Canadian Provincial MOUs and/or Agreements. The program supports Compliance Enforcement (Section 400) and Organization Registration and Certification (Section 500), the ERO Enterprise Operating Plan, the ERO Enterprise Long-Term Strategy, and aligns with NPCC Board of Director goals and strategies.

The CORC Program Area scope covers:

1) The identification, registration and certification of those entities responsible for meeting the NERC Reliability Standards and any approved Regional Standards;
2) The implementation of the risk-based NERC Compliance Monitoring and Enforcement Program (CMEP) IT Tool (Align) in the United States, including the compliance monitoring, assessment and enforcement of NERC Reliability Standards and Regional Reliability Standards;
3) In accordance with the relevant memorandums of understanding (MOU's), the implementation of the risk-based NERC CMEP in Ontario and Nova Scotia, including the assessment and enforcement of NERC Reliability Standards and Regional Reliability Standards effective in those jurisdictions,
4) The implementation of the Québec Reliability Standards Compliance Monitoring and Enforcement Program (QCMEP), including the compliance monitoring, assessment and enforcement of NERC Reliability Standards and Regional Reliability Standards effective in Quebec, and
5) The implementation of the New Brunswick Compliance Monitoring and Enforcement Program (NBCMEP) in New Brunswick, including the compliance monitoring, assessment and enforcement recommendations of the NERC Reliability Standards and Regional Reliability Standards effective in New Brunswick.

Through the CORC Program Area, NPCC strives to be a strong enforcement authority that is objective, fair, and promotes a culture of reliability excellence through risk-informed compliance monitoring, mitigation, enforcement, and registration. To accomplish this goal, CORC is

divided into three sub-program areas: Compliance Fundamentals; Compliance Audits and Investigations; and Compliance Mitigation and Enforcement.

Compliance Fundamentals

The Compliance Fundamentals sub-program area is responsible for registration and certification activities and for general compliance activities that span across the other three sub-program areas. The Compliance Fundamentals sub-program area:

- Identifies and registers the BES owners, operators, and users that are required to comply with the NERC and Regional Reliability Standards,
- Conducts Certifications in accordance with the NERC ROP,
- Leads the development of the annual implementation plans (ERO Enterprise, NPCC, Quebec, New Brunswick),
- Implements the ERO Enterprise CMEP IT tool (Align),
- Responds to any Complaints submitted to NPCC,
- Maintains any NPCC specific compliance tools or programs needed, and;
- Conducts outreach, training, and education to support the implementation of Reliability Standards.
- Conducts Inherent Risk Assessments (IRA) on registered entities,
- Conducts Internal Controls Evaluations (ICE) on volunteering registered entities,
- Assists with the development of the annual CMEP implementation plans, and;
- Provides the basis for each registered entity's Compliance Oversight Plan.

Compliance Audits and Investigations

The Compliance Audits and Investigations sub-program area is responsible for conducting all compliance monitoring activities. The Compliance Audits and Investigations sub-program area is focused on the most significant risks to the BPS. The Compliance Audits and Investigations sub-program area:

- Conducts NPCC compliance monitoring activities, including audits, spot checks, and guided self-certifications,
- Incorporates the results of the IRA and ICE into its compliance monitoring process,
- Issues reports, including audit reports, spot check reports, guided self-certification reports, and;
- Implements and maintains the Critical Infrastructure Protection (CIP) Standards Technical Feasibility Exceptions process.

Compliance Mitigation and Enforcement

The Compliance Mitigation and Enforcement sub-program area is responsible for undertaking enforcement activities in accordance with risk-based approaches and conducting technical assessments of registered entities' plans and activities to mitigate noncompliance. Depending on the jurisdiction, enforcement either makes official recommendations to the appropriate regulatory authority or assists and coordinates with NERC to make such official recommendations. The Compliance Mitigation and Enforcement sub-program area:

- Determines the relevant facts and circumstances necessary to understand each noncompliance,
- Evaluates and assigns a risk level to each noncompliance,
- Evaluates and approves the mitigation activities or Mitigation Plan for each noncompliance,
- Assesses the relevant compliance history for each noncompliance,
- Determines the disposition method for each noncompliance,

- Calculates penalty sanctions in consistent fashion, and
- Evaluates registered entities for the self-logging program.

2020 Key Assumptions and Cost Impacts

2019	Projected 2020
5 On-Site Audits	8 On-Site O&P Audits
8 On-Site CIP Audits	10 On-Site CIP Audits
28 Off-Site Audits	40 Off-Site O&P Audits
24 Off-Site CIP Audits	25 Off-Site CIP Audits
15 Spot Checks	10 Spot Checks
18 Guided self-certifications	40 Self-certifications
33 Inherent Risk Assessments	50 Inherent Risk Assessments
4 On-site O&P Internal Control Evaluations	7 On-site O&P Internal Control Evaluations
5 On-site CIP Internal Control Evaluations	10 On-Site CIP Internal Control Evaluations
216 Violations (Estimated)	225 Violations (Estimated)
Settlements Covering 50 Violations	Settlements Covering 80 Violations
0 Hearings (Unbudgeted)	1 Hearings (Unbudgeted)
1 CI (Estimated)	1 CI (Estimated)
3 Entity Certifications	2 Entity Certifications

- Compliance Monitoring activities are projected to increase in 2020 from 2019 and will be cost effectively addressed with the addition of one FTE on the compliance staff, which is offset by a decrease in contract audit costs.
- The 2020 Business Plan projects increases in Enforcement Processing activities over the 2019 Budget. It is expected that the increase in violation processing will continue in 2021. This is partly due to the increase in the number of cyber systems that are in scope for compliance in most jurisdictions.
- One Compliance Investigation is projected for 2020. Compliance Investigations are manpower intensive for NPCC staff (requiring allocation of more resources and potentially higher than normal costs).

2020 Goals and Key Deliverables

- Conduct scheduled compliance monitoring and enforcement activities pursuant to the 2020 Implementation Plans.
- Continue applying risk-based approaches for CMEP, registration, and certification activities.
- Identify potential issues related to NERC Reliability Standards as a result of compliance monitoring, enforcement and event analysis activities.
- Continue to implement compliance responsibilities in Canada based on the unique regulatory structure specific to each provincial and/or governmental jurisdiction.
- Evaluate monitoring, violation processing, risk-assessment, registration and certification program for sufficiency and effectiveness. Modify as needed.
- Collaborate within the ERO Enterprise to develop and implement a common and consistent CMEP IT tool (Align) for compliance processes, information systems, and methods among Regions.

- Provide education and outreach to the registered entities on all CMEP, registration, and certification topics, including the development and implementation of the ERO Enterprise Registration and CMEP software reporting systems and tools.
- Conduct two in-person Compliance Workshops.
- Develop annual reports for QCMEP/CMEP activity in Québec and New Brunswick.
- Develop and/or provide input on 2020 CMEP Implementation Plans (ERO Enterprise, NPCC, Québec, New Brunswick).
- Attend training necessary and/or beneficial to performing Registration, Certification, Entity Risk Assessment, Monitoring, and Enforcement activities.
- Assure that NPCC staff is appropriately trained to conduct Certification and Auditing activities.
- Provide detailed responses to oversight activity performed by NERC, FERC, and other relevant authorities.
- Continue to perform and update IRAs for registered entities.
- Continue to perform an ICE for registered entities that volunteer for such an assessment.
- Continue to assess internal controls during monitoring engagements
- Conduct 2020 Compliance Engagement Schedule based on risk to the BPS and number of registered entities and promote the ERO Risk-Based Approach initiatives by:
    - Utilizing the Audit Checklist and Auditor's Handbook for all on-site and off-site audits.
    - Preparing an updated Inherent Risk Assessment as necessary for all scheduled engagements and performing an Internal Controls Evaluation for all entities that volunteer.
- Continue to perform comprehensive enforcement investigations to determine the relevant facts and circumstances necessary to understand each noncompliance, assess the risk, and evaluate the mitigation activities or Mitigation Plan for each noncompliance. Determine the disposition method in accordance with established risk-based approaches (i.e. Compliance Exceptions, FFTs, Simplified Identification Correction Method (Québec), Settlements, etc.)
- Evaluate the mitigation activities or Mitigation Plan for each noncompliance, track the progress and verify the completion of each Mitigation Plan.
- As necessary, represent NPCC during any enforcement hearings before the NPCC Hearing Body, the NERC Hearing Body, the Régie, or the NBEUB.
- Evaluate registered entities for the self-logging program.
- Analyze noncompliance trends and associated risks in order to develop guidance to registered entities in support of a culture of reliability.
- Perform outreach (webinars, workshops) to educate entities on noncompliance root causes and on techniques for noncompliance assessment and communication associated with self-reporting to NPCC; including the provision of guidance on the development of mitigation activities that will prevent recurrence.
- Assess evolving cyber security risks for opportunities to develop internal control flow diagrams in order to provide entity guidance

Based on the portion of professional/technical staff time and other resources devoted to Compliance monitoring and enforcement and organizational registration and certification, NPCC estimates that it will expend 56% of its resources on this activity.

Resource Requirements

Personnel

- One additional FTE to increase in-house expertise rather than utilizing contractor labor. The increase in personnel expenses will be offset by a decrease in Consultants and Contracts.

Fixed Assets

- No new functionality is planned for the Compliance Issues Tracking System and CMEP Data Administration Application at this time based on the planned implementation of the ERO Enterprise CMEP IT Tool (Align).

Compliance Monitoring and Enforcement and Organization Registration and Certification Program

Funding sources and related expenses for the compliance enforcement and organization registration and certification section of the 2020 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2019 Budget & Projection, and 2020 Budget
Compliance Monitoring and Enforcement and Organization Registration and Certification

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 8,183,815	$ 8,183,815	$ -	$ 9,002,624	$ 818,809
	Penalty Sanctions	-	-	-	69,994	69,994
Total ERO Funding		**$ 8,183,815**	**$ 8,183,815**	**$ -**	**$ 9,072,617**	**$ 888,802**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 8,183,815**	**$ 8,183,815**	**$ -**	**$ 9,072,617**	**$ 888,802**
Expenses						
Personnel Expenses						
	Salaries	$ 2,815,882	$ 2,720,882	$ (95,000)	$ 2,928,438	$ 112,557
	Payroll Taxes	191,849	188,849	(3,000)	202,717	10,867
	Benefits	585,543	572,543	(13,000)	732,104	146,561
	Retirement Costs	301,025	287,025	(14,000)	314,664	13,638
Total Personnel Expenses		**$ 3,894,299**	**$ 3,769,299**	**$ (125,000)**	**$ 4,177,923**	**$ 283,624**
Meeting Expenses						
	Meetings & Conference Calls	$ 15,000	$ 15,000	$ -	$ 15,000	$ -
	Travel	295,400	295,400	-	300,400	5,000
Total Meeting Expenses		**$ 310,400**	**$ 310,400**	**$ -**	**$ 315,400**	**$ 5,000**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 1,357,150	$ 1,337,150	$ (20,000)	$ 1,097,150	$ (260,000)
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ 1,357,150**	**$ 1,337,150**	**$ (20,000)**	**$ 1,097,150**	**$ (260,000)**
	Total Direct Expenses	**$ 5,561,849**	**$ 5,416,849**	**$ (145,000)**	**$ 5,590,473**	**$ 28,624**
Indirect Expenses		**$ 3,303,230**	**$ 3,303,230**	**$ -**	**$ 3,420,003**	**$ 116,772**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 8,865,080**	**$ 8,720,080**	**$ (145,000)**	**$ 9,010,476**	**$ 145,396**
Change in Assets		**$ (681,264)**	**$ (536,264)**	**$ 145,000**	**$ 62,141**	**$ 743,406**
Fixed Asset Additions (C)		**$ (48,392)**	**$ (48,392)**	**$ -**	**$ 99,157**	**$ 147,550**
TOTAL BUDGET (=B+C)		**$ 8,816,687**	**$ 8,671,687**	**$ (145,000)**	**$ 9,109,633**	**$ 292,946**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (632,872)**	**$ (487,872)**	**$ 145,000**	**$ (37,016)**	**$ 595,856**

Reliability Assessment and Performance Analysis Program

Reliability Assessment and Performance Analysis Program Resources (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	5.83	5.43	-0.40
Direct Expenses	$2,216,468	$2,169,556	($46,912)
Indirect Expenses	$1,086,356	$1,031,701	($54,655)
Other Non-Operating Expenses	$0	$0	$0
Fixed Asset Additions	$33,192	$29,913	($3,279)
Total Funding Requirement	$3,336,016	$3,231,169	($104,847)

Program Scope and Functional Description

NPCC, through its top technical committee, the Reliability Coordinating Committee (RCC), integrates the deliverables of its Task Forces' and Working Groups' Reliability Assessment and Performance Analysis (RAPA) related activities.

Seasonal assessments of the overall NPCC resource adequacy are performed and possible actions to mitigate any potential problems are identified. NPCC reviews operations and disturbances both internal and external to the Region in order to identify any lessons to be learned and recommends any necessary follow-up actions.

If appropriate, enhancements to Regional Standards or NPCC's more stringent, Regionally-specific reliability criteria requirements are also recommended. NPCC promotes and conducts both inter-Area and inter-Regional studies to enhance reliability and operational effectiveness and provides a forum for the discussion and coordination of operating issues within the NPCC Region and with other Regions.

2020 Key Focus Areas

In collaboration with NERC, Key Focus Area activities for 2020 include:

- Integration of RAPA information systems for assessments and associated data requirements, including expanded and enhanced enterprise-wide data collection and analysis systems and capabilities for performance analyses, with a focus on independent and technically sound reliability assessments supporting delivery of high quality reports.
- Development of assessment and performance analysis techniques as well as resource capabilities and tools, including probabilistic and scenario evaluations, which address the impacts of new technologies, changing resource or demand resource composition, and environmental related regulations or legislation.
- Support ERO activities to identify key reliability risks and appropriate projects designed to enhance reliability and/or mitigate risks.
- Providing technical resources to support NERC special reliability assessments which focus on specific reliability risk areas in geographic areas with specific identified reliability concerns.
- Advancing analytical capabilities for identifying and determining reliability risks and conducting associated related reliability assessments.

Eastern Interconnection Reliability Assessment Group (ERAG)

The primary function of the Eastern Interconnection Reliability Assessment Group (ERAG) is to support reliability of the bulk-power system in the Eastern Interconnection through periodic reviews of generation and transmission expansion. These assessments are conducted by the ERAG Committee. These assessment-related activities support ERO Goal 3: "*Reduction of Known Risks to Reliability*" and 4 "*Identification and Assessment of Emerging Reliability Risks*."

NPCC RAPA staff participates with the ERAG Committee as one of the four Eastern Interconnection Regional Entities, and acts as the liaison between the ERAG MMWG and the NPCC SS-37 Working Group.

ERAG Committee Activities 2020 Goals and Deliverables

- Transition the steady state and dynamic simulation base case data compilation and development work from ERAG to the Eastern Interconnection Planning Collaborative (EIPC).
- Support EIPC designation and certification as the Eastern Interconnection MOD-032, Requirement R4 Designee.
- During a transition period oversee the steady state and dynamic simulation base case data compilation and development.
- Oversee the ERAG assessment plan and coordinate assessment efforts with NERC Assessment Program staff. Determine the targeted ERAG assessment topic for 2020. Determine to method of assessment: analytical study, research effort, peer review.
- Make appropriate revisions, as necessary, to the ERAG Strategic Direction (i.e. anticipated new developments in MMWG process and system assessments).
- Develop and approve the ERAG activity budgets.

Multi-Regional Modeling Working Group 2020 Goals and Deliverables

- During a transition period of the Eastern Interconnection base case development MOD-032-1, Requirement 4 Designee period from ERAG to EIPC facilitate the completion of the steady state and dynamic simulation base case data compilation and development for the 2020 series of cases.
- Check and confirm that the dynamic model data passes all applicable checks and acceptance criteria.
- Incorporate dispatch information into the future and seasonal MMWG base cases so that the dispatches are more closely aligned with economic dispatch practices.
- Continue to improve the representations of the governor-turbine plant control models.
- Apply MMWG base case non-disclosure agreement process so that MMWG cases continue to have sufficient protections in place for use and transmittal of confidential data and information.

ERAG System Assessments 2020 Goals and Deliverables

- Determine an appropriate topic of focus for the 2020 ERAG Assessment. In recent years, ERAG has conducted peer reviews on select topics in lieu of conducting assessments. Conduct the 2020 ERAG Assessment and prepare any associated documentation.
- Coordinate Assessment efforts with the NERC Reliability Assessment and System Analysis (RASA) Program staff to incorporate any risk-based or other approaches to supplement NERC Assessments.

Bulk Electric System Notification and Exception (BESnet) application and Exception Request (ERs)

NPCC supports maintenance of the BESnet application and the processing of the Regional BES Exception Requests (ERs), including periodic certifications that the basis for an Element being included or excluded in the BES through the Exception remains valid. No NPCC Exception Requests are due for recertification in 2020. Analysis of an Exception Request from a New Brunswick entity may extend into 2020.

2020 NERC Activities

NPCC will provide the Regional perspective with appropriate NPCC RAPA staff participation on selective NERC Technical Committees and key related NERC Subcommittees, Task Forces and Working Groups, including:

- Event Analysis Subcommittee (EAS)
- Inverter-Based Resource Performance Task Force (IRPTF)
- Performance Analysis Subcommittee (PAS)
  - Demand Response Availability Data System Working Group (DADSWG)
  - Battery Availability Data System Working Group (BADSWG)
  - Generating Availability Data System Working Group (GADSWG)
  - Misoperation Information Data Analysis System (MIDASWG)
  - Transmission Availability Data System Working Group (TADSWG)
- Reliability Assessment Subcommittee (RAS)
  - Probabilistic Assessment Working Group (PAWG)
- System Analysis and Modeling Subcommittee (SAMS)
  - Load Modeling Task Force (LMTF)
  - Power Plant Model Verification Task Force (PPMVTF)
  - Node Breaker Modeling Group (NBMG)
- System Protection and Control Subcommittee (SPCS)
- Synchronized Measurement Subcommittee (SMS)
- System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG)
- Battery and Storage Task Force (BASTF)

ERO – Executive Management Group (EMG) 2020 Activities

Provide analytic support for the ERO-EMG:

- Operations Leadership Team;
- Bulk Electric System Exception Process Working Group, under Organization Registration and Certification Group (ORCG);
- ERO-RAPA Group; and,
- Other activities as directed by the ERO-Executive Management Group.

2020 Goals and Key Deliverables

NPCC Task Force activities support ERO Goal No. 3 "*Identification and Assessment of Significant Risks to Reliability*" and ERO Goal No. 4 "*Identification and Assessment of Emerging Risks to Reliability.*"

Task Force on Coordination of Planning

The primary mission of the NPCC Task Force on Coordination of Planning (TFCP) is to promote reliability through the coordination of NPCC Area and NERC planning processes and activities.

TFCP Reliability Assessment and Performance Analysis 2020 Goals and Deliverables

- Coordinate NPCC responses to the approved NERC Essential Reliability Services Working Group recommendations with the Task Force on Coordination of Operation and the Task Force on System Studies to ensure that the recommendations are addressed.
- Coordinate the development of additional NPCC Criteria as necessary and track any new and developing Regional NPCC Standards through the NPCC Regional Standards Committee.
- Monitor industry practices and make recommendations to the NPCC Regional Standards Committee regarding related NERC Standards.
- Oversee the NPCC Directory No. 1 Implementation Plan (Dated: September 30, 2015).
- Oversee the activities of the NPCC CP-8 Working Group.
- Evaluate and recommend RCC approval of NPCC Area Transmission Reviews.
- Evaluate and recommend RCC approval of NPCC Area Reviews of Resource Adequacy.
- Coordinate, monitor, review, and make recommendations on the retirement of existing in-service and/or implementation of proposed or modified Special Protection Systems Remedial Action Schemes.
- Coordinate the NPCC transition from SPS to RAS in accordance with PRC-012-2.
-
- Lead the NPCC Task Forces in conducting the review of the reliability and cost benefit of Directory No. 1, Design and Operation of the BPS.
- Support related reliability activities, including consideration of any requests for sub-regional assessments.
- Keep informed on studies and developments in neighboring systems which might impact NPCC reliability.
- Review Events Analysis Lessons Learned using the Events Analysis discussion/review template.

Task Force on System Studies

The primary mission of the NPCC Task Force on System Studies (TFSS) is to provide active overall coordination of system studies of the reliability of the interconnected bulk power systems and for the review of related NPCC documents.

TFSS Reliability Assessment and Performance Analysis 2020 Goals and Deliverables

- Review and recommend approval of Area Transmission Reviews.
- Review and classify new and modified Remedial Action Schemes.
- Review and Implement the NPCC A-10 Criteria.
- Perform annual review and update of the Major Project List.
- Participate in the development and submission of NPCC comments/inputs into the development of regional and/or continent-wide reliability standards that address the NERC Reliability Standards.
- Provide support and technical input, for Task Force related Bulk Electric System risks as identified by the NERC Reliability Issues Steering Committee.

- Review existing NPCC Regional Criteria and procedures for validation of data used in power flow and dynamic simulations; propose changes to provide for adequate data validation.
- Perform investigation of Distributed Energy Resources modeling practices.
- Annually develop a library of power flow base cases and associated dynamic cases.
- Enable the annual review of the NPCC event replication procedure and ensure the preparedness of the NPCC Planning Coordinators to develop base cases for a required investigation of a major system event in or affecting NPCC and support the performance of event replication by benchmarking simulations against actual system performance.
- Work with software vendors and NERC to enhance the capability for dynamic simulations.
- Continue to investigate the use of dynamic load models for transient stability studies.
- Investigate the use of load monitoring equipment to aid in the benchmarking of dynamic load models used in transient stability studies.

Task Force on System Protection

The primary purpose of the NPCC Task Force on System Protection (TFSP) is to promote the reliable and efficient operation of the interconnected bulk power systems in Northeastern North America through the establishment of directories, criteria, guidelines, and procedures and coordination of design, relative to NPCC protection systems.

TFSP Reliability Assessment and Performance Analysis 2020 Goals and Deliverables

- Assess proposed protection systems and Special Protection Systems/Remedial Action Schemes.
- Participate and/or serve as lead Task Force in the implementation of applicable Regional NERC Reliability Standards.
- Review and respond to Questions, Requests for Interpretations and/or Clarifications related to bulk power system protection requirements in NPCC Directories and Criteria.
- Participate in the ongoing development and submission of NPCC inputs/comments into the development of related NERC Reliability Standards.
- Monitor the NPCC metric on protection system Misoperation Risk Index Score calculations.
- Review mitigations and/or progress reports for Bulk Power System Risk Reduction Implementation.
- Provide support and technical input for related protection system risks as identified by the NERC Reliability Issues Steering Committee.
- Conduct review/development of related NPCC Directories.
- Consistent with the TFSP's scope, conduct joint meeting with other Regions to share best practices and experiences.
- Review ongoing changes to the North American Reliability Corporation Critical Infrastructure Protection Standards and evaluate impacts to Registered Entities Protection Systems, SCADA, and Monitoring Systems.

Task Force on Coordination of Operation

The NPCC Task Force on Coordination of Operation (TFCO) primarily facilitates the coordination of operations among the NPCC Reliability Coordinator areas and adjacent NERC Regions to enhance the reliability of the bulk power system.

TFCO Reliability Assessment and Performance Analysis 2020 Goals and Deliverables

- Prepare and conduct the spring and autumn NPCC System Operator Seminars.
- Develop and securely disseminate the annual compilation of "Facilities for Notification."
- Support and take part in the biennial, continent-wide Grid Security Exercise, including a review of the associated reports and Lessons Learned.
- Complete a triennial review of the individual RC Areas' restoration plans.
- Support an annual enhanced, wide area restoration drill among the Reliability Coordinator areas of NPCC and their neighboring Reliability Coordinators, incorporating the annual review of the NPCC regional restoration plan.
- Conduct pre-seasonal NPCC Reliability Assessments.
- Conduct reviews of applicable NPCC Directories, Criteria, Guides and Procedures in accordance with their applicable review dates.
- Coordinate system awareness among NPCC Reliability Coordinators through periodic conference calls.
- Monitor the trends and impacts of the changing resource mix and the effects of the proliferation of the new resources on real-time operations, as well as behavior during and impacts on recovery and restoration plans.
- Provide assistance to the NERC Event Analysis Process and evaluate the operational applicability of the identified Lessons Learned.
- Review a biennial summary of operating tool failures and lessons learned for the preceding study period.
- Review and analyze the performance of Simultaneous Activation of Reserve (SAR) implementation following an event to enhance the process.

NPCC Regulatory/Governmental Affairs Advisory Group

The NPCC Governmental/Regulatory Affairs Advisory Group provides a forum where industry and governmental and/or regulatory representatives can exchange views and strive to develop consensus policy recommendations on reliability issues specific to the NPCC Region (Northeastern United States and Eastern Canada) and share actionable information among NPCC, NERC and other related governmental and/or regulatory agencies related to Regional reliability matters.

The Regulatory/Governmental Affairs Advisory Group activities indicated below are done in support of ERO Goal No. 3 "*Reduction of Known Risks to Reliability*" and ERO Goal No. 4 "*Identification and Assessment of Emerging Risks to Reliability*."

NPCC Regulatory/Governmental Affairs Advisory Group 2020 Goals and Deliverables

- Continued outreach to NPCC's state electricity and environmental regulators stressing the importance of understanding and considering reliability impacts during the development of State/Provincial initiatives (such as the identified Essential Reliability Services, Distributed Energy Resource integration).
- Focus on initiatives concerning regional planning, distributed energy resource requirements, the timing of new generation resources and transmission infrastructure projects.

Based on the portion of professional/technical staff time and other resources devoted to Reliability Assessment and Performance Analysis, NPCC estimates that it will expend 20% of its resources on these activities.

Resource Requirements

Personnel

- Decrease of 0.40 FTE represents reallocation of staff to situation awareness to address shift in focus areas.

Consultants and Contracts

- Increase in consultants and contracts expense is associated with increase in inherent risk and emerging risk reliability assessments.

Reliability Assessment and Performance Analysis Program

Funding sources and related expenses for the Reliability Assessment and Performance Analysis section of the 2019 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures 2019 Budget & Projection, and 2020 Budget Reliability Assessment and Performance Analysis						
		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 3,332,686	$ 3,332,686	$ -	$ 3,210,055	$ (122,632)
	Penalty Sanctions	-	-	-	21,115	21,115
Total ERO Funding		**$ 3,332,686**	**$ 3,332,686**	**$ -**	**$ 3,231,169**	**$ (101,517)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 3,332,686**	**$ 3,332,686**	**$ -**	**$ 3,231,169**	**$ (101,517)**
Expenses						
Personnel Expenses						
	Salaries	$ 1,135,264	$ 1,135,264	$ -	$ 1,006,128	$ (129,136)
	Payroll Taxes	69,027	69,027	-	64,023	(5,004)
	Benefits	219,655	219,655	-	218,787	(868)
	Retirement Costs	123,322	123,322	-	109,418	(13,904)
Total Personnel Expenses		**$ 1,547,268**	**$ 1,547,268**	**$ -**	**$ 1,398,356**	**$ (148,912)**
Meeting Expenses						
	Meetings & Conference Calls	$ 23,000	$ 23,000	$ -	$ 22,000	$ (1,000)
	Travel	216,200	216,200	-	216,200	-
Total Meeting Expenses		**$ 239,200**	**$ 239,200**	**$ -**	**$ 238,200**	**$ (1,000)**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 430,000	$ 430,000	$ -	$ 533,000	$ 103,000
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ 430,000**	**$ 430,000**	**$ -**	**$ 533,000**	**$ 103,000**
	Total Direct Expenses	**$ 2,216,468**	**$ 2,216,468**	**$ -**	**$ 2,169,556**	**$ (46,912)**
Indirect Expenses		**$ 1,132,814**	**$ 1,132,814**	**$ -**	**$ 1,031,701**	**$ (101,113)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 3,349,282**	**$ 3,349,282**	**$ -**	**$ 3,201,257**	**$ (148,025)**
Change in Assets		**$ (16,596)**	**$ (16,596)**	**$ -**	**$ 29,913**	**$ 46,508**
Fixed Asset Additions (C)		**$ (16,596)**	**$ (16,596)**	**$ -**	**$ 29,913**	**$ 46,508**
TOTAL BUDGET (=B+C)		**$ 3,332,686**	**$ 3,332,686**	**$ -**	**$ 3,231,169**	**$ (101,517)**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (0)**	**$ (0)**	**$ -**	**$ 0**	**$ 0**

Training, Education, and Operator Certification Program

Training, Education, and Operator Certification Program Resources (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	0.10	0.10	0.00
Direct Expenses	$233,297	$219,862	($13,435)
Indirect Expenses	$18,634	$19,000	$366
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$569	$551	($18)
Total Funding Requirement	$252,500	$239,412	($13,088)

Program Scope and Functional Description

The NPCC Training, Education, and Operator Certification program supports NERC Rules of Procedure Section 900. The program provides education and training necessary to understand and operate the bulk electric system. The target audience of the program is bulk power system operating personnel - including system operations personnel, operations support personnel (engineering and information technology), supervisors and managers, and training personnel. NPCC staff training and development is incorporated within each respective program area.

Training Program Background and Description

This NPCC Program establishes and coordinates training for system operators relating to inter-Reliability Coordinator area matters, criteria, terminology, standards and operating procedures and instructions. It includes development and execution of training seminars, held twice yearly, at which:

- potential operational problems for the coming season are discussed,
- physical layouts and electrical characteristics of the NPCC and PJM Areas are discussed,
- application of NPCC Directory and NERC Standard requirements pertinent to operation are discussed,
- major industry issues that are important for system operators are discussed,
- significant disturbances are reviewed for lessons learned; and
- table-top drills and communication and coordination exercises are conducted.

The seminars promote camaraderie and better communication among system operators from the NPCC and PJM Reliability Coordinator (RC) Areas and the Nova Scotia Balancing Authority (BA) area. PJM RC has significant interaction with the NPCC RCs and system operators from PJM have been regular participants at past seminars. Examples of specific topics addressed at recent seminars include: 1) additions and impacts to operations of renewable resources, 2) the development of conditions and violations related to major system Blackouts, 3) human performance related to system operations, 4) cybersecurity threats and system operator concerns, 5) system restoration approaches and tie-ins to neighboring systems and 6) application of NPCC Simultaneous Activation of Reserve. Usually, control center visits are included as part of the seminar activities.

This Program also provides for:

- sharing of RC/BA existing training program and system simulator area content;
- verification and sharing of training methods;
- evaluation of training and simulator aids as they become available;
- opportunities to consolidate training among the NPCC RCs and BAs, which includes opportunities to share training material and training sessions; and
- exchange of information on internal methods of system operator training.

The training activities indicated below are done in support of ERO Goals No. 3 "*Reduction of Known Reliability Risks*" and No. 6 "*Effective and Efficient Operation*". Related contributing activities to these goals include "Working with industry forums, expand communication and encourage sharing of good industry practices for increasing Human Performance (HP) effectiveness", "Acquire, engage, develop, and retain highly qualified talent with requisite technical expertise to execute the ERO Enterprise's statutory functions" and "Strengthen coordination among NERC, Regional Entities with cross-border footprints, and North American stakeholders in support of ERO Enterprise reliability and security priorities."

Funding Drivers and Reliability Benefits

- System operators participating in the Seminars: 1) share their approaches to addressing operational problems and learn about the characteristics of neighboring systems; 2) gain exposure to NPCC issues and current industry operational topics; 3) review recent NPCC and PJM major external disturbances; 4) review key operational related content in NPCC Directories and NERC Standards; and 5) participate in hands-on "table top exercises" pertaining to system operational practices. PJM system operators and trainers are also invited to participate and normally attend and participate in these seminars;
- Seminar attendees also receive Continuing Education Hours (CEHs) (normally 3 CEHs) and operator trainers from each RC / BA area can utilize the seminar content by including it in their internal training programs to provide CEHs to all system operators; The seminars help to improve system operational coordination through better contact among system operators at other Reliability Coordinator Areas.
- Continually review and revise the curriculum of the training seminars to better emphasize NERC Standard requirements related to system operation, NPCC wide-area operations and Regionally-specific criteria and procedures.
- Enhance system operator awareness and knowledge of the standards, criteria and procedures that are applied in real time operation;
- Provide more sharing of training approaches, exchange of information on internal methods of system operator selection, training material and training sessions;
- Enhance efficiency and cost savings in the training programs in the NPCC RC/BA areas:
- Provide a forum among NPCC RC/BA areas for sharing of approaches to meet the requirements of the NERC PER and COM standards;
- NPCC will conduct two Standards and Compliance workshops in 2020, for NPCC Stakeholders, for the express purpose of providing the most current and applicable information related to the development of NERC and Regional Reliability Standards and the implementation of the Compliance Monitoring and Enforcement Program (CMEP).

2020 Key Assumptions

In addition to the Spring and Fall Standards and Compliance workshops, NPCC regularly conducts System Operators seminars, , specifically designed with table top exercises, targeted breakout classroom sessions and presentations on current industry related activities, to provide for the most efficient exchange of information between the NPCC and Areas' training staff, NPCC Compliance and Standards staff and the NPCC Stakeholders. Presentations in the past have been conducted by FERC, NERC and Stakeholder representatives in addition to NPCC and Areas' training staff members. To supplement these seminars and workshops, NPCC may develop webinars that will focus on specific topics pertinent to developments related to system operations, compliance program implementation, standards development or technical issues.

The System Operator seminars involve system operators' participants from the NPCC RC/BA Areas and PJM, and are held in early May and early November.

Training, Education and Operator Certification 2020 Goals and Deliverables

- Prepare and conduct the 2020 Spring and Fall NPCC System Operator Seminars.
- Continue collaboration and sharing of the intended RC/BA approaches, experiences and materials to task identification and training development
- As needed, enhance the NPCC repository of training resources and learning verification activities addressing fundamental power system topics, training methods and operation procedure training exercises, which may be shared as elements of operator training in compliance with NERC Standards PER-003-1 "*Operating Personnel Credentials"* and PER-005-2 "*Operations Personnel Training.*"
- Develop on-line operational training webinars that focus on specific topics pertinent to compliance program implementation, standards development or technical issues.
- Conduct Spring and Fall 2020 Standards and Compliance workshops addressing the development of NERC and Regional Reliability Standards and the implementation of the Compliance Monitoring and Enforcement Program (CMEP).

Based on the portion of professional/technical staff time and other resources devoted to training, education, and operator certification, NPCC estimates that it will expend 2% of its resources on this activity.

Resource Requirements

- No significant changes.

Training, Education, and Operator Certification Program

Funding sources and related expenses for the training, education, and operator certification section of the 2020 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2019 Budget & Projection, and 2020 Budget
Training, Education, and Operator Certification

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 184,943	$ 184,943	$ -	$ 171,524	$ (13,420)
	Penalty Sanctions	-	-	-	389	389
Total ERO Funding		**$ 184,943**	**$ 184,943**	**$ -**	**$ 171,912**	**$ (13,031)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	67,500	67,500	-	67,500	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 252,443**	**$ 252,443**	**$ -**	**$ 239,412**	**$ (13,031)**
Expenses						
Personnel Expenses						
	Salaries	$ 18,600	$ 18,600	$ -	$ 11,793	$ (6,807)
	Payroll Taxes	1,513	1,513	-	939	(575)
	Benefits	6,805	6,805	-	5,652	(1,153)
	Retirement Costs	2,379	2,379	-	1,478	(900)
Total Personnel Expenses		**$ 29,297**	**$ 29,297**	**$ -**	**$ 19,862**	**$ (9,435)**
Meeting Expenses						
	Meetings & Conference Calls	$ 189,000	$ 189,000	$ -	$ 185,000	$ (4,000)
	Travel	15,000	15,000	-	15,000	-
Total Meeting Expenses		**$ 204,000**	**$ 204,000**	**$ -**	**$ 200,000**	**$ (4,000)**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ -	$ -	$ -	$ -	$ -
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Total Direct Expenses	**$ 233,297**	**$ 233,297**	**$ -**	**$ 219,862**	**$ (13,435)**
Indirect Expenses		**$ 19,431**	**$ 19,431**	**$ -**	**$ 19,000**	**$ (431)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 252,728**	**$ 252,728**	**$ -**	**$ 238,862**	**$ (13,866)**
Change in Assets		**$ (285)**	**$ (285)**	**$ -**	**$ 551**	**$ 836**
Fixed Asset Additions (C)		**$ (285)**	**$ (285)**	**$ -**	**$ 551**	**$ 836**
TOTAL BUDGET (=B+C)		**$ 252,443**	**$ 252,443**	**$ -**	**$ 239,412**	**$ (13,031)**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (0)**	**$ (0)**	**$ -**	**$ 0**	**$ 0**

Situation Awareness and Infrastructure Security Program

Situation Awareness and Infrastructure Security Program Resources (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	5.00	5.40	0.40
Direct Expenses	$1,409,379	$1,450,129	$40,750
Indirect Expenses	$931,695	$1,026,001	$94,306
Other Non-Operating Expenses	$0	$0	$0
Fixed Asset Additions	$28,466	$29,747	$1,281
Total Funding Requirement	$2,369,540	$2,505,877	$136,337

Program Scope and Functional Description

The Situation Awareness and Infrastructure Security Program is the combination of near real - time awareness of conditions on the bulk power system with the programs necessary to increase the physical and cyber security of the electricity infrastructure, including the operation and maintenance of tools and other support services for the benefit of Reliability Coordinators and the system operators within the registered entities. Maintaining the real-time awareness of conditions on the interconnected bulk power systems by the NPCC Reliability Coordinator is critical to maintaining reliable operation within NPCC, including the communication of information concerning system conditions and abnormal events among the neighboring system operators responsible for the reliable operation of the bulk power systems. When an event does occur, it is critical to provide a forum for active coordination of reliability and operation among the NPCC Reliability Coordinator areas and neighboring NERC Regions and to use an event as a learning opportunity to enhance the reliability of the interconnected bulk power system through the lessons learned, which can be gleaned from such an event.

These Situation Awareness and Infrastructure Security activities indicated below are done in support of ERO Goal No. 3 "*Reduction of Known Risks to Reliability*" and ERO Goal No. 5 – "*Identification and Reduction of Cyber and Physical Security Risks."* Related contributing activities to Goal 3 include "Analyzing system performance, events, and relationships among data sources to identify risks and mitigation strategies and provide recommendations and lessons learned, including those that are lower impact, to discover potential reliability trends early in their lifecycles" and "Promoting the use of NERC cause codes to establish a common understanding of HP triggers, collect and evaluate trends in data, and develop metrics as needed." Contributing activities to Goal 5 include "Working closely with industry, NERC's Critical Infrastructure Protection Committee (CIPC), governmental agencies, the national labs, industry forums, trade associations and other stakeholders, promote leading security practices, information sharing and analysis, and resilience."

Event Analysis Program Description

NERC, Regions and the industry analyze events, identify the lessons to be learned, and conduct a formal cause code analysis.

The Event Analysis Program recognizes that many events which occur on the bulk power system beyond those identified through NERC Reliability Standard EOP-004-4, "Event Reporting," can have varying levels of significance to the electric system, providing otherwise unrealized lessons

to be learned from these events and the trending of such events to identify possible reliability concerns. By implementing a "bottom-up" approach to an event review within the framework of the NERC Event Analysis Program, consistency, comparability, flexibility, quality and timeliness in the event analysis process will be promoted by NPCC, the registered entities and NERC in a collaborative initiative.

Upon the identification of an event, the goal of the Event Analysis Program is to:

- identify what transpired;
- categorize the event within the NERC Event Analysis Program;
- establish the sequence of events;
- understand the essential root causes of the event;
- identify recommendations or corrective actions; and,
- develop and disseminate to the industry lessons to be learned, so that the operational reliability of the bulk power system can be further enhanced.

In assessing any system event, it is recognized that, if the timely dissemination of lessons learned from an event is to be realized, any potential compliance implications associated with an event must be addressed and dismissed. Throughout an event analysis effort, to make this process successful and complete, and to solidify the "bottom-up" approach, registered entities are encouraged to establish a liaison between the event analysis and compliance functions internal to the registered entity during the event analysis process. This serves to facilitate the development of a registered entity compliance self-assessment report, which is accomplished by performing a sufficiency review of the reliability standards deemed applicable to the event, assisting in the self-reporting of possible violations should any be discovered.

To complete this voluntary effort, the entity, the Region and NERC staff will collaborate to assess the NERC Brief Report or Event Analysis Report and perform a formal cause code analysis, identifying a root cause and publish any pertinent lessons learned gathered from the event.

The adoption by NERC of the Event Analysis Program brings clarity and certainty about what system events are relevant to analyze and to what level of detail, targeting potential risks to the reliability of the bulk power system for a more detailed and in-depth analysis. Consistent with risk-based approach, only concise and succinct reviews are desired for more minor events. ERO EAP delineates the expectations, roles and responsibilities of the registered entities, NPCC and NERC in a uniform review of system events by the industry and promotes a timely development and dissemination of valuable lessons learned to the industry. The identification and tracking of emerging common risks through the assessment of events will further distinguish trends, which may be of concern to reliability. By rigorously pursuing analysis of the lesser events on the system, learning from these events and developing recommendations, risk of larger events can be mitigated.

NPCC staff works step-by-step with the registered entity throughout the total event analysis process, permitting the entity to assume the primary role in the development of the initial event analysis, lessons learned, which may benefit the industry, along with assisting and overseeing the Standards sufficiency review and cause coding process for trending and reporting. NPCC staff, throughout the process, guides, supports and stands as an advocate of the registered entity as they continue to develop an improved culture of reliability and compliance.

2020 Key Assumptions

- The monitoring of Lessons Learned will continue to be a major focus of NERC and NPCC in 2020, including:
  - continued reporting, for applicable qualifying eventsin the voluntary Event Analysis Program, of more detailed information on station equipment failure, per recommendation of the AC Substation Equipment Task Force, to solicit and collect this data, to aid in future analysis of station equipment failures and to identify trends that may be a threat to the reliability of the Bulk Electric System,
  - Introduction of a new EAP categories, implemented to capture the effect of "non-consequential" loss of inverter type resources and similarly DC ties between two separate asynchronous systems,
  - continued utilization of a revised Category 1h - EMS/Loss of monitoring or control at a Control Center events Brief Report template and Addendum, developed with the input of the EMS Working Group to ensure continuation of analysis of such events to improve information collection related to such events and associated analysis, taking into account the modifications to the mandatory EOP-004-4 reporting requirements thresholds.
- NERC will post updates to the Critical Infrastructure Protection Standards to address the outstanding FERC Directives and the remaining industry concerns that were not satisfactorily responded to by the version 5 Transition Advisory Group, including:
  - The new CIP-008 reporting requirements
  - The supply chain standards, which become mandatory July 2020
  - CIP modification SDT effort on virtualization
  - Updates to CIP-002 and CIP-003
- TFIST will address cloud computing initiatives, through technical consensus comments and ballot recommendations, specifically on the topics of:
  - Cloud computing work on BES Cyber Systems Information updates to CIP-004 and CIP-011
  - Continued evaluation of coordination between CIP standards and Federal Risk and Authorization Management Program (FedRAMP) - an assessment and authorization process which U.S. federal agencies have been directed by the Office of Management and Budget to ensure security is in place when accessing cloud computing products and services
- Resource allocation to this program area will support expanded Events Analysis activities; coordination with NERC's evolving E-ISAC capabilities; and physical and cyber security outreach efforts.

Situation Awareness 2020 Goals and Deliverables

- NPCC will provide the Regional perspective and support through NPCC Event Analysis staff participation on selective NERC Technical Committees and key related NERC Subcommittees, Task Forces and Working Groups, including the Event Analysis Subcommittee, the ERO – Event Analysis/Situational Awareness Group; and utilization of The Event Analysis Management System (TEAMS).
- Work directly with applicable NPCC Task Forces and Working Groups to provide an in-depth assessment of Lessons Learned unique to the NPCC Members and NPCC Criteria.
- Promote NPCC's Event Analysis group's process for sharing and dissemination of the detailed Event Analysis Report information among industry participants (Registered Entities).
- Incorporate the Lessons Learned from participation in the GridEx V wide-area exercise.

- Monitor the operational status of the bulk power system and coordinate normal and pre-emergency communication, awareness and assistance in addition to the same during an emergency among the Reliability Coordinators within NPCC. Notify the Reliability Coordinators of significant bulk power system events that have occurred in one Reliability Coordinator Area, and which have the potential to impact reliability in other NPCC Reliability Coordinator Areas or Regions external to NPCC. These events include contingencies on the bulk power system, potential shortfalls of operating reserve, operating problems, potential security threats and potential threats or disruptions to the cyber systems.
- Conduct a daily conference call to serve as a complement to the NPCC Emergency Preparedness Conference Call. The participants of the call are the Reliability Coordinators within NPCC and its neighboring RCs, the Midcontinent ISO and PJM. The conference call is implemented through a bridge, the initiation of the call quickly ringing all pre-selected telephones simultaneously. The goal of the call is to alert all Reliability Coordinators of emerging problems. If no system difficulties are anticipated for the day, no unnecessary information is to be discussed. Subjects for discussion are limited to credible events which could impact the ability of an entity to serve its load and meet its operating reserve obligations or would impose a burden to the interconnection, including the following: Projected Load; Adverse Weather; Operating Reserve; Generation; Transmission; and Sabotage. If conditions worsen in the course of the day, the NPCC Emergency Preparedness Conference Call will be implemented.
- Monthly test of the satellite telephone network, to ensure the capability for continued voice communications among NPCC and its Reliability Coordinators. This back-up communications system will function in the event of a collapse of the Public Switched Telephone Network, permitting continued cross-border voice communications among the Canadian Reliability Coordinators of NPCC, the Reliability Coordinators in the United States as well as NPCC Situation Awareness staff.
- Coordination and communication with the NERC Bulk Power System Awareness group in preparation for and during ongoing significant events in the NPCC's footprint and participation in the ERO Enterprise-wide Situation Awareness activities. Monitor the status of the bulk power system through the NERC Situational Awareness-FERC, NERC, Regions version 3 (SAFNRv3) tool, a near real-time operating display for the United States portion of the Reliability Coordinators footprints of North America, an enhanced visualization tool, providing more timely and accurate assessments of current conditions affecting the BPS, thus enabling NERC's and Regions' obligation to maintain situational awareness and facilitation of timely communications and collaboration with key stakeholders .

Infrastructure Security Objectives

NPCC's critical infrastructure security objectives are defined within the scope of the NPCC Task Force on Infrastructure Security & Technology, and include, but are not limited to:

- Providing a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee; and,
- Representing and advocating NPCC's position in the activities of NERC groups involved in the development and/or implementation of physical and cyber security.

NPCC's physical and cyber security outreach efforts, will supplement infrastructure security objectives and support the ERO Enterprise contributing activity of "Working closely with industry, NERC's Critical Infrastructure Protection Committee (CIPC), governmental agencies, the national labs, industry forums, trade associations and other stakeholders, promote leading

security practices, information sharing and analysis, and resilience." NPCC's Physical Security Working Group – an NPCC group of physical security experts formed to discuss, in a secure environment, emerging threats, trends and new security technologies and strategies utilized by NPCC registered entities for the protection of their facilities in the physical arena. The Working Group is tasked with developing approaches to physical security that will enhance the reliability and resiliency of the BPS and further address any physical security issues that could challenge efficient operation of the BPS, including pertinent items identified in the biennial RISC report, under Physical and Cyber Security Vulnerabilities. The Group will function as a clearinghouse for intelligence information received from Federal, State and Local partners and will disseminate such information received to NPCC registered entities. In addition, the Working Group shall develop, review, and provide regional input on various industry physical security initiatives, working groups, and task forces, as appropriate.

NPCC's 2020 infrastructure security goals and objectives, support ERO Goal No. 5 – "*Identification and Reduction of Cyber and Physical Risks*." Related contributing activities to this Goal include "Expand the use, availability, and value of physical security and cybersecurity threat and vulnerability information sharing, including cross sector communications, and analytics" and "Leverage engagement with registered entities to encourage effective security practices and controls."

Infrastructure Security 2020 Goals and Deliverables

- Monitor the reliable implementation of the Cyber Security Standards.
- Monitor the Homeland Security Information Network, E- ISAC, NERC Alerts and Canadian Information Sharing and share information with the NPCC CO-8 Working Group, NPCC PSWG and NPCC members' cyber security experts.
- Review and submit comments on NERC proposed Reliability Standards, modified Reliability Standards, proposed Guidelines and modified Guidelines related to Infrastructure Security and Technology.
- Keep current on all governmental agencies regarding applicable security recommendations and requirements, and other applicable security and reliability recommendations and keep the RCC and its committees appropriately informed, e.g. Sector Specific Plan.
- Conduct an annual review of cross border emergency telecommunications to verify each Area can communicate with each other.
- Provide support and technical input for Task Force related Bulk Electric System risks as identified by the NERC Reliability Issues Steering Committee. TFIST and PSWG will conduct a thorough review, provide comments as necessary and act on posted materials as directed and applicable.
- Support the NERC CIPC Grid Exercise Working Group in GridEx VI planning and simulation.
- Review infrastructure security & technologies and provide recommendations to enhance physical and cyber security in compliance with NERC guidelines/standards.
- Provide recommendations to enhance physical and cyber security, in compliance with NERC standards, based on assessments of available and emerging infrastructure security technologies, methodologies, and best practices.
- Sponsor periodic workshop presentations to address timely issues and update NPCC Members associated with infrastructure security and technology.

- Provide education, awareness, and support for Cross Sector coordination in Entity agreements and response plans with focus upon Telecommunications, Water and Natural Gas, including monitoring and sharing with the E-ISAC.

Related System Operations Security 2020 Goals and Deliverables

NPCC's system operations security objectives are defined within the scope of the NPCC Task Force on Coordination of Operation and include, but are not limited to:

- Coordinating inter-Regional pre-emergency actions in the event of a threat to the security of the Northeastern North American bulk power supply system; and,
- Assisting in the development of real time operating tools ensuring cyber security concerns are addressed.

Based on the portion of professional/technical staff time and other resources devoted to situation awareness and infrastructure security, NPCC estimates that it will expend 15% of its resources on this activity.

Resource Requirements

Personnel

- Increase of 0.40 FTE represents reallocation of staff to address shift in focus areas.

Situation Awareness and Infrastructure Security Program

Funding sources and related expenses for the situation awareness and infrastructure security section of the 2020 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2019 Budget & Projection, and 2020 Budget
Situation Awareness and Infrastructure Security

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 2,366,685	$ 2,366,685	$ -	$ 2,484,879	$ 118,195
	Penalty Sanctions	-	-	-	20,998	20,998
Total ERO Funding		**$ 2,366,685**	**$ 2,366,685**	**$ -**	**$ 2,505,877**	**$ 139,193**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 2,366,685**	**$ 2,366,685**	**$ -**	**$ 2,505,877**	**$ 139,193**
Expenses						
Personnel Expenses						
	Salaries	$ 832,408	$ 832,408	$ -	$ 924,110	$ 91,702
	Payroll Taxes	57,432	57,432	-	61,713	4,281
	Benefits	201,196	201,196	-	202,020	824
	Retirement Costs	89,043	89,043	-	99,986	10,943
Total Personnel Expenses		**$ 1,180,079**	**$ 1,180,079**	**$ -**	**$ 1,287,829**	**$ 107,750**
Meeting Expenses						
	Meetings & Conference Calls	$ 10,000	$ 10,000	$ -	$ 8,000	$ (2,000)
	Travel	89,300	89,300	-	94,300	5,000
Total Meeting Expenses		**$ 99,300**	**$ 99,300**	**$ -**	**$ 102,300**	**$ 3,000**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 130,000	$ 130,000	$ -	$ 60,000	$ (70,000)
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ 130,000**	**$ 130,000**	**$ -**	**$ 60,000**	**$ (70,000)**
	Total Direct Expenses	**$ 1,409,379**	**$ 1,409,379**	**$ -**	**$ 1,450,129**	**$ 40,750**
Indirect Expenses		**$ 971,538**	**$ 971,538**	**$ -**	**$ 1,026,001**	**$ 54,463**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 2,380,918**	**$ 2,380,918**	**$ -**	**$ 2,476,130**	**$ 95,212**
Change in Assets		**$ (14,233)**	**$ (14,233)**	**$ -**	**$ 29,747**	**$ 43,980**
Total Funding (A) Requirement		**$ 2,395,151**	**$ 2,395,151**	**$ -**	**$ 2,446,383**	**$ 51,232**
Fixed Asset Additions						
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	(14,233)	(14,233)	-	29,747	43,980
Fixed Asset Additions (C)		**(14,233)**	**(14,233)**	**-**	**29,747**	**43,980**
TOTAL BUDGET (=B+C)		2,366,685	2,366,685	-	2,505,877	139,193
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (0)**	**$ (0)**	**$ -**	**$ 0**	**$ 0**

Administrative Services

Administrative Services Program Resources (in whole dollars)	Direct Expenses			FTEs		
	2019 Budget	2020 Budget	Increase (Decrease)	2019 Budget	2020 Budget	Increase (Decrease)
Technical Committees and Members Forum	$74,483	$75,793	$1,310	0.50	0.50	0.00
General and Administrative [2]	$3,391,903	$3,874,453	$482,550	2.50	2.73	0.23
Legal and Regulatory	$612,934	$761,007	$148,073	1.00	2.00	1.00
Information Technology	$1,083,781	$1,314,119	$230,339	2.00	2.00	0.00
Human Resources	$156,946	$158,731	$1,785	1.00	1.00	0.00
Finance and Accounting	$642,798	$703,291	$60,493	2.00	2.00	0.00
Total Administrative Services[1]	$5,962,845	$6,887,395	$924,550	9.00	10.23	1.23

[1] NPCC's 2020 Administrative Services Direct Expenses and Fixed Assets total $6,887,395, of which $409,450 is allocated to NPCC's Criteria Services division, which is a non-statutory function. As a result of the allocation to the Criteria Services division, the Administrative Expenditures included in the 2020 statutory budget are $6,477,945 which is an increase of $743,865 from the 2019 budget of $5,734,080.

[2] Succession implementation costs of $444,540 included in General and Administrative Direct Expenses will be funded from Board approved Business Continuity Reserves and will not impact assessments.

Program Scope and Functional Description

Administrative services support the previously identified five program areas of: reliability standards; compliance monitoring and enforcement and organization registration and certification; training, education, and operator certification; reliability assessment and performance analysis; and situation awareness and infrastructure security. Administrative services consist of: technical committees and members' forums; general and administrative; legal and regulatory; information technology; human resources; and finance and accounting.

Methodology for Allocation of Administrative Services Expenses to Programs

NPCC total overhead expenses, such as office rent and office costs, will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Administrative Services

Funding sources and related expenses for the Administrative Services section of the 2020 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2019 Budget & Projection, and 2020 Budget
ADMINISTRATIVE SERVICES

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ (100,108)	$ (100,108)	$ -	$ (593,855)	$ (493,746)
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ (100,108)**	**$ (100,108)**	**$ -**	**$ (593,855)**	**$ (493,746)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	55,800	55,800
Total Funding (A)		**$ (100,108)**	**$ (100,108)**	**$ -**	**$ (538,055)**	**$ (437,946)**
Expenses						
Personnel Expenses						
	Salaries	$ 2,147,254	$ 2,126,254	$ (21,000)	$ 2,433,049	$ 285,794
	Payroll Taxes	107,437	105,437	(2,000)	126,595	19,158
	Benefits	493,115	478,115	(15,000)	674,649	181,534
	Retirement Costs	296,142	294,142	(2,000)	313,571	17,429
Total Personnel Expenses		**$ 3,043,948**	**$ 3,003,948**	**$ (40,000)**	**$ 3,547,864**	**$ 503,916**
Meeting Expenses						
	Meetings & Conference Calls	$ 162,750	$ 162,750	$ -	$ 162,750	$ -
	Travel	135,100	135,100	-	129,100	(6,000)
Total Meeting Expenses		**$ 297,850**	**$ 297,850**	**$ -**	**$ 291,850**	**$ (6,000)**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 95,000	$ 95,000	$ -	$ 361,000	$ 266,000
	Office Rent	820,700	820,700	-	832,700	12,000
	Office Costs	676,347	676,347	-	685,981	9,634
	Professional Services	978,000	978,000	-	947,000	(31,000)
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	51,000	51,000	-	51,000	-
Total Operating Expenses		**$ 2,621,047**	**$ 2,621,047**	**$ -**	**$ 2,877,681**	**$ 256,634**
	Total Direct Expenses	**$ 5,962,845**	**$ 5,922,845**	**$ (40,000)**	**$ 6,717,395**	**$ 754,550**
Indirect Expenses		**$ (6,217,845)**	**$ (6,217,845)**	**$ -**	**$ (6,272,855)**	**$ (55,010)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ (255,000)**	**$ (295,000)**	**$ (40,000)**	**$ 444,540**	**$ 699,540**
Change in Assets		**$ 154,892**	**$ 194,892**	**$ 40,000**	**$ (982,595)**	**$ (1,137,486)**
Fixed Asset Additions (C)		**$ 255,000**	**$ 255,000**	**$ -**	**$ -**	**$ (255,000)**
TOTAL BUDGET (=B+C)		**$ -**	**$ (40,000)**	**$ (40,000)**	**$ 444,540**	**$ 444,540**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (100,108)**	**$ (60,108)**	**$ 40,000**	**$ (982,595)**	**$ (882,486)**

Technical Committees and Member Forums

Program Scope and Functional Description

The success of the NPCC programs depends on the active and direct volunteerism and participation of its members. The stakeholders are the source of subject matter expertise in the industry. To promote the reliable and efficient operation of the interconnected bulk power systems in Northeastern North America, NPCC invites high-level policy makers from Federal, Provincial and State regulatory and/or governmental authorities and senior executives within NPCC and NERC to identify and discuss emerging issues related to the reliability of the NPCC Region.

2020 Key Assumptions

- NPCC's standing committee and subgroup structure for effective stakeholder involvement will continue in 2020.
- NPCC will continue to utilize methods to encourage active involvement in its Regional programs that require less stakeholder travel and face-to-face meetings, as the economy improves in 2020.
- NPCC will continue to invest in technology and innovation to allow efficient collaboration on technical issues related to reliability.

The Technical Committees and Member Forums activities indicated below are done in support of ERO Goal No. 4 "*Identification and Assessment of Emerging Risks to Reliability*." A related contributing activity to this Goal is to "Educate policy makers, regulators, and the industry of reliability effects and interconnection requirements for the changing resource mix."

Technical Committees and Member Forums 2020 Goals and Deliverables

- The 2020 NPCC General Meeting provides an opportunity for NPCC Members to meet high level policy makers from Federal, Provincial and State regulatory and/or governmental authorities and senior NERC and NPCC executives to discuss topics related to the reliable planning and operation of the power system, including consideration of emerging reliability, critical infrastructure and environmental issues; and,
- The objective of the NPCC Public Information Committee is to highlight and summarize NPCC activities and accomplishments in the past year, disseminate and coordinate the appropriate release of information to the media, respond to related requests for information, and coordinate with related NPCC Area, NERC media and public information activities. Activities anticipated include, but are not limited to:
    - Conducting the Media Event – release of the Summer 2020 NPCC Reliability Assessment; and,
    - Participation in NERC Regional communication initiatives:
        - Regional communications teleconferences as required
        - Coordination of Emergency or Blackout communications plans
        - Coordination with other NERC activities as required (i.e., situation awareness, event analysis, reliability assessments, etc.)

Resource Requirements

- No significant changes.

General and Administrative

Program Scope and Functional Description

The NPCC general and administrative function provides executive management of the corporation, management of NPCC office, and other administrative support programs.

NPCC total overhead expenses, such as office rent and office costs, will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Resource Requirements

- During 2020 an executive search will be conducted in order to identify a successor CEO to transition into that role by vote of the Membership at its Annual Meeting to become effective January 1, 2021. The incumbent President and CEO has identified a planned retirement during the first quarter of 2021. The expectation is that the identified successor will join NPCC by early November or December, 2020 in an executive leadership capacity. Costs related to the executive search efforts and succession plan implementation will be funded from the existing Business Continuity Reserve, identified by the NPCC Board of Directors in 2017 and approved at varying intervals within 2020 by the Board for reserve release. Therefore, 2020 assessments will not be impacted by these succession-related expenses.

Legal and Regulatory

Program Scope and Functional Description

NPCC's professional legal services provide counsel to the President and CEO, Board of Directors, Senior Vice President and COO, Treasurer, General Counsel and staff on a wide range of legal and regulatory matters including legislation, corporate law, code of conduct, confidentiality, governance, employment law, tax matters, contract law and other areas affecting NPCC, consistent with ERO Goal 6. In support of ERO Goal 4., NPCC's in-house counsel evaluates internal controls and corporate, operational, strategic and reputational risk, and participates in risk identification, evaluation and mitigation activities. In-house counsel provides legal advice to advance significant corporate policy and strategic planning initiatives and also provide legal support to other program areas on matters arising in connection with the performance of NPCC's delegated functions. In-house counsel draft agreements and pleadings and provide interpretations of relevant statutes, regulations, court opinions, and regulatory decisions of FERC, state agencies and provincial authorities. Outside counsel, as necessary, reviews items filed with the governmental agencies for legal sufficiency, maintains relationships with U.S. and Canadian jurisdictions and provides contract review.

Resource Requirements

Personnel

- NPCC plans to hire one FTE in the Legal and Regulatory program in 2020. A paralegal/legal assistant will support General Counsel and add to the overall efficiency of the organization. This addition is partially offset by a projected decrease in professional fees.

Information Technology

Program Scope and Functional Description

NPCC's Information Technology services ensure information assets and the environment in which they operate are secure and in conformance to NPCC IT Policies and Procedures and all applicable Critical Electric Infrastructure Information protection and Confidentiality requirements. NPCC maintains an offsite backup server for continuity of essential operations in the event that its primary location is unavailable.

NPCC supports the ERO efforts to implement, operate and maintain software tools supporting common enterprise wide operations and leveraging ERO solutions which have been approved by the ERO Executive Management Group (ERO EMG), which is comprised of the senior leadership of NERC and each of the Regional Entities. NPCC's budget assumes the availability of enterprise software tools as described in NERC's business plan and budget. If implementation of these software applications is delayed or otherwise not available as planned, NPCC could incur additional costs to implement ERO Enterprise-wide programs pending the availability of these applications.

NERC and the Regional Entities are committed to working collaboratively to minimize duplication of effort and investments, and improve operational efficiency. This collaboration continues to refine existing strategies, governance and procurement practices applicable to the development, operation and maintenance of enterprise architecture, software and data systems supporting complementary and combined NERC and Regional Entity operations.

The NERC information technology budget does not supplant NPCC's need for IT expenditures for specific regional projects and internal region specific IT support needs. NPCC's 2020 Business Plan and Budget assumes agreed-upon ERO Enterprise applications will be available and includes only NPCC costs for Region specific support needs.

2020 Key Assumptions

- Continue to maintain the compliance portal through collaboration with other Regional Entities and NERC (CUG), while transitioning to the ERO Enterprise CMEP IT Tool (Align).
- Support the Event Analysis program through continued participation in the tools used for the tracking and analysis of system events and identification of better practice elements.
- Support the Bulk Electric System Exception Process (BEP) to enable and facilitate tracking and processing of exceptions submitted. Maintenance of the BESNET support services such as updates, patching, coordinating issues with NERC.
- Support Cyber Security Reviews done by Compliance to provide advisory role during those reviews.

2020 Goals and Key Deliverables

Responsibilities encompass a variety of complex technical, administrative, and supervisory work in the development, installation, and maintenance of information technology systems. IT goals include, but are not limited to:

- Continue to expand the utilization of the document management system throughout the company.
- Constantly review and evaluate security measures taken to reduce breach of security risks.

- Ensure all information systems are functional and secure, and that all applications running on those systems meet business requirements for performance, availability, and security.
- Provide outreach and education to NPCC members in IT best practices.
- Continually improve Disaster Recovery and Business Continuity policies and practices to ensure continuity and reliability of IT and business related services.
- Upgrade various hardware and equipment.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2020.

Fixed Assets

- Capital expenditures planned for 2020 include the continuing implementation and enhancement of the document management system and equipment upgrades.

Human Resources

Program Scope and Functional Description

NPCC has assembled an exceptional team of highly qualified employees to carry out its activities. The human resources function, in adherence with applicable federal and state laws, designs, plans, and implements human resources policies and procedures, including: staffing; compensation; benefits; employee relations; training and development; and employee time tracking.

Resource Requirements

- No significant changes.

Accounting and Finance

Program Scope and Functional Description

The accounting and finance function directs the overall financial plans and accounting practices of the organization; oversees treasury, accounting, budget, tax, and audit activities; and oversees financial and accounting system controls and standards. NPCC uses a CPA firm to prepare its unaudited statements of activities and financial statements for quarterly reviews. Independent audits have identified this system as a best practice.

2020 Goals and Key Deliverables

The objectives are to provide or obtain the financial and accounting services for NPCC and coordinate with NERC requirements:

- Utilize the NERC System of Accounts for consistency
- Utilize an accrual method of accounting for consistency with NERC in methodology
- Alignment of changes in budget and changes in aggregate assessment
- Cash Management
- Budget Development using the NERC budget template formats
- Forecasts and Projections
- Alignment of NPCC Committees, Task Forces and Working Groups with the programs
- Payroll and expense administration
- Preparation of unaudited Quarterly Financial Variance Reports
- IRS Reporting
- Annual Independent Audit initiated by the Regional Entity

Resource Requirements

- No significant changes.

Regional Entity Assessment Analysis

In the area of assessments there are distinct funding mechanisms as outlined in the following table. For the Regional Entity division, the North American Electric Reliability Corporation (NERC) will assess load serving entities (LSEs) or their designees (within NPCC the designees are the Balancing Authority Areas (BAAs) for New York, New England, New Brunswick, Nova Scotia, Ontario and Québec) based upon 2017 proportional Net Energy for Load (NEL) and other specific program area funding arrangements and make quarterly remittances to the Regional Entity on or about the 15th day of January, April, July and October. For funding associated with the Criteria Services division, the Independent System Operators/Balancing Authority Areas (ISO/BAAs) will be assessed by NPCC for their proportional share of the divisional budget based upon 2017 NEL within the Region. Non ISO/BAA Full Members will be assessed no membership fee.

NPCC Cost Allocation Methodology

The accompanying table provides information regarding cost allocation for both the Regional Entity division and the Criteria Services division of NPCC, including the details associated with the funding of the Compliance Program within the RE division. For purposes of determining assessments to support NPCC's resource requirements, costs are allocated among the ISOs/BAAs within NPCC as the designees for the load serving entities (LSEs) in New York, New England, Ontario, Québec, New Brunswick and Nova Scotia.

In order to reflect and respect the international membership and nature of NPCC, any sub-Regional reliability assessment costs in response to U.S. only regulatory initiatives will be considered for allocation to U.S. only ISOs/BAAs consistent with NERC Rules of Procedure section 1102. Additionally, the compliance responsibilities and authorities within the U.S., and the specific compliance responsibilities within each of the Canadian provinces within NPCC, and the attendant costs of portions of the compliance program differ among the areas within the Regional Entity. Within the U.S. portion of NPCC all costs attributable to delegated (statutory) functions performed by NPCC, including all compliance functions, are assessed based on a net energy for load (NEL) allocation. Within the Canadian portion of NPCC those costs attributable to compliance functions performed by NPCC on behalf of provincial governmental and/or regulatory authorities are allocated consistent with the unique Memoranda of Understanding or Agreements that have been entered into for those provinces. To address these different compliance regimes, NPCC developed a composite cost allocation methodology that allocates U.S. only reliability assessment and compliance costs on a fair and equitable basis within the Regional Entity.

As an initial step of that methodology, the NEL for each of the BAAs and their relative percentage to the NPCC total NEL is calculated for the most recent year for which data is available, the second previous year. In order to establish the RE division funding requirements for each Balancing Authority Area on a NEL basis for all programs except for Compliance, the proposed expenses and fixed assets of all other programs are calculated and the adjustment for the RE division cash reserve requirement is identified. Any penalty monies received from NPCC registered entities within the U.S. prior to June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs. Consistent with each of the Canadian provincial MOUs and agreements, all penalty monies resulting from compliance actions within Canada, if any, would remain within the applicable province. The total budgeted fees for NPCC

workshop participation are indicated as a credit, with the resultant addition being the RE division assessment, without the compliance program costs, calculated on a NEL basis.
In accordance with the *NPCC Amended and Restated Bylaws* the CS division proposed expenses and fixed assets of all programs are calculated and the adjustment for the CS division cash reserve requirement is identified, with the resultant addition being the CS division funding requirement and assessment, calculated on a NEL basis.

For costs associated with the RE division compliance program, NPCC's allocation methodology apportions _% of the costs for the program, attributed to CORC Fundamentals (CF), between the BAAs in the United States and Canada on a NEL basis.

Audits and Investigations (AI) related costs, representing _% of the costs of the compliance program, are allocated between U.S. and Canadian BAAs in NPCC, and among the Canadian provinces, using an audit-based methodology. The audit-based methodology incorporates relative costs based on categories of compliance audits which are reflective of their size and complexity, as well as the differing compliance program implementation models that are utilized in NPCC due to the international nature of the Regional Entity. The portion allocated to the U.S. BAAs in NPCC is calculated using the audit-based methodology, and this amount is then re-allocated between the New York and New England BAAs based on their relative NEL.

The remaining _% of the costs of the compliance program represent Mitigation and Enforcement (ME) related costs and are allocated between U.S. and Canadian BAAs in NPCC, and among the Canadian provinces, using an enforcement activity based methodology. Based on historical data, NPCC reviewed each BAAs percentage of violations, mitigation plans and settlement agreements to determine each BAA's total average percentage of enforcement activities. The portion allocated to the U.S. BAA's in NPCC is calculated using the enforcement activity based methodology, and this amount is then re-allocated between the New York and New England BAAs based on their relative NEL.

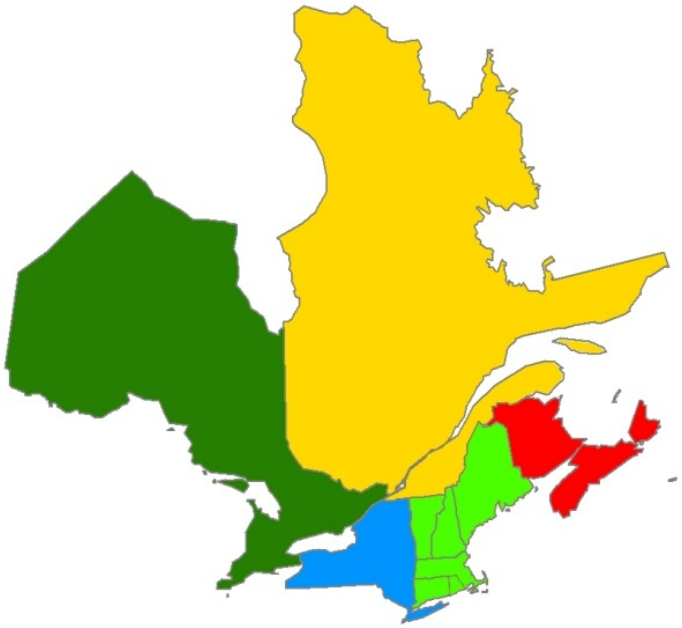
Any penalty monies received from NPCC registered entities within the U.S. by June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs, and then added to the total compliance program expenses and fixed assets to yield a total compliance program assessment.

The CORC actual vs budget variance from the most recent year for which audited financials are available is broken out from the rest of the Adjustment to Cash Reserve and assigned to the CORC program allocation of costs. Within Québec these costs are funded directly by the regulator, therefore, the assignment of program area variances needs to respect those specific circumstances.

Finally, the total RE division funding requirements and assessments by BAA are tabulated and the total funding requirements and assessments for NPCC, both the RE and CS divisions, are combined.

Table to be Inserted

Section B — Supplemental Financial Information
2020 Business Plan and Budget



Section B – Supplemental Financial Information

Reserve Balance

Table B-1 Reserve Balance

Working Capital and Operating Reserve Analysis 2019-2020
REGIONAL ENTITY DIVISION

	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Total Reserve, December 31, 2018	4,969,944	2,713,006	1,316,938	940,000
Plus: 2019 ERO Funding (from LSEs or designees)	15,003,411	15,003,411		
Plus: 2019 Other funding sources	67,500	67,500		
Less: 2019 Projected expenses & capital expenditures	(15,618,891)	(15,618,891)		
Projected Total Reserve, December 31, 2019	**4,421,964**	**2,165,026**	**1,316,938**	**940,000**
Desired Total Reserve, December 31, 2020	**3,402,353**	1,523,478 [1]	1,383,415 [2]	495,460 [3]
Less: Projected Total Reserve, December 31, 2019	(4,421,964)	(2,165,026)	(1,316,938)	(940,000)
Increase(decrease) in assessments to achieve desired Total Reserve	**(1,019,611)**	(641,548)	66,477	(444,540)

2020 Expenses and Capital Expenditures	16,601,647
Less: Penalty Sanctions [4]	(120,000)
Less: Other Funding Sources	(123,300)
Less: Release of Business Continuity Reserve Funds [3]	(444,540)
Adjustment to Working Capital to achieve desired Total Reserve balance [2]	66,477
Adjustment to Operating Reserve to achieve desired Total Reserve balance [1]	(641,548)
2020 Assessment	**15,338,737**

[1] Operating Reserve within a range from 8.33% to 25.00% of Budget. $1,523,478 represents 9.18% of the 2020 budget of $16,601,647
[2] Working Capital equal to 8.33% of Budget. $1,383,415 represents 8.33% of the 2020 budget of $16,601,647
[3] Business Continuity Reserve (BCR) established in 2017 as approved by the NPCC Board of Directors to fund Succession Planning related expenses.
[4] Represents collections July 1, 2018 to June 30, 2019.

Explanation of Changes in Reserve Policy from Prior Year

There was no change to the existing Working Capital and Operating Reserve Policy. A separate Business Continuity Reserve (BCR) in the amount of $1,000,000 (allocated between the Regional Entity and Criteria Services divisions) was established in 2017 as approved by the NPCC Board of Directors, upon recommendation by the Management Development and Compensation Committee and endorsement by the Finance and Audit Committee, to be drawn upon as subsequently brought before the Board of Directors for approval of release of funds in association with President & CEO succession related activities associated with the planned or a sudden retirement, as well as other sudden changing workforce staffing requirements which could be brought about by coincident multiple staff retirements.

Breakdown by Statement of Activity Sections

The following detailed schedules are in support of the Regional Entity division Statement of Activities on page 13 of the 2020 Business Plan and Budget. All significant variances have been disclosed by program area in the preceding pages.

Penalty Sanctions

U.S. penalty monies received prior to June 30, 2019 are to be used to offset assessments in the 2020 Budget, as documented in the NERC Policy – Accounting, Financial Statement, and Budgetary Treatment of Penalties Imposed and Received for Violations of Reliability Standard. Penalty monies received from July 1, 2018 through June 30, 2019 are listed below. Penalty monies received from July 1, 2019 through June 30, 2020 will be used to offset U.S. load serving entity designee assessments in the 2021 Budget.

Allocation Method: U.S. penalty sanctions received have been allocated to the following Regional Entity division programs to reduce assessments: Reliability Standards; Compliance Monitoring & Enforcement and Organization Registration & Certification; Reliability Assessments and Performance Analysis; Training, Education and Operator Certification; and Situation Awareness and Infrastructure Security. U.S. penalty sanctions are allocated based upon the number of FTEs in the Program divided by the aggregate total FTEs in the Programs receiving the allocation.

Table B-2 Penalty Sanctions

Penalty Sanctions Received Prior to June 30, 2019	Date Received	Amount Received
	7/16/2018	$ 120,000.00
Total Penalties Received		**$ 120,000.00**

Table B-3 Supplemental Funding

Outside Funding Breakdown By Program (excluding ERO Assessments & Penalty Sanctions)	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget
Reliability Standards				
Total	$ -	$ -	$ -	$ -
Compliance Monitoring, Enforcement & Org. Registration				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Reliability Assessment and Performance Analysis				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Training and Education				
Workshops	$ 67,500	$ 67,500	$ 67,500	$ -
Total	$ 64,000	$ 67,500	$ 67,500	$ -
Situation Awareness and Infrastructure Security				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Technical Committees and Member Forums				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Administrative Services Programs				
Interest & Investment Income	$ -	$ -	$ 55,800	$ 55,800
Total	$ -	$ -	$ 55,800	$ 55,800
Total Outside Funding	$ 64,000	$ 67,500	$ 123,300	$ 55,800

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- NPCC estimates interest & investment income of $55,800 in 2020 from investment of reserves in a 100% U.S. Treasury money market fund, which will offset 2020 assessments.

Table B-4 Personnel Expenses

Personnel Expenses	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Salaries					
Salary	$ 7,298,280	$ 7,298,280	$ 7,664,262	$ 365,982	5.0%
Employment Agency Fees	$ 10,000	$ 10,000	$ 16,000	$ 6,000	60.0%
Temporary Office Services	$ 24,000	$ 24,000	$ 24,000	$ -	0.0%
Total Salaries	$ 7,332,280	$ 7,332,280	$ 7,704,262	$ 371,982	5.1%
Total Payroll Taxes	$ 449,994	$ 449,994	$ 479,019	$ 29,026	6.5%
Benefits					
Education Reimbursement	$ 32,000	$ 32,000	$ 27,500	$ (4,500)	-14.1%
Training and Seminars	$ 58,290	$ 58,290	$ 83,580	$ 25,290	43.4%
Medical Insurance	$ 901,783	$ 901,783	$ 1,168,854	$ 267,071	29.6%
Life-LTD-STD Insurance	$ 94,804	$ 94,804	$ 110,889	$ 16,085	17.0%
Worker's Compensation	$ 20,000	$ 20,000	$ 32,000	$ 12,000	60.0%
Vacation	$ 506,201	$ 506,201	$ 504,062	$ (2,139)	-0.4%
Relocation	$ -	$ -	$ -	$ -	-
Total Benefits	$ 1,613,078	$ 1,613,078	$ 1,926,885	$ 313,806	19.5%
Retirement					
Pension Contribution	$ -	$ -	$ -	$ -	-
Employee Savings Plan	$ 741,511	$ 741,511	$ 770,950	$ 29,440	4.0%
Savings Admin	$ 36,000	$ 36,000	$ 36,000	$ -	0.0%
Deferred Compensation	$ 76,000	$ 76,000	$ 76,000	$ -	0.0%
Total Retirement	$ 853,511	$ 853,511	$ 882,950	$ 29,440	3.4%
Total Personnel Costs	**$ 10,248,862**	**$ 10,248,862**	**$ 10,993,117**	**$ 744,254**	**7.3%**
FTEs	38.86	38.86	41.09	2.23	5.7%
Cost per FTE					
Salaries	$ 188,685	$ 188,685	$ 187,497	$ (1,187)	-0.6%
Payroll Taxes	$ 11,580	$ 11,580	$ 11,658	$ 78	0.7%
Benefits	$ 41,510	$ 41,510	$ 46,894	$ 5,384	13.0%
Retirement	$ 21,964	$ 21,964	$ 21,488	$ (476)	-2.2%
Total Cost per FTE	**$ 263,738**	**$ 263,738**	**$ 267,538**	**$ 3,799**	**1.4%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- Increase in Training and Seminars is due to an increase per employee training budget.
- Medical insurance increase reflects a premium increase of 8%. Additionally, less employees are waiving NPCC coverage for that of a prior employer.
- Personnel expenses include some succession planning related costs that will be funded through business continuity reserves and do not impact assessments.

Table B-5 Meeting Expense

Meeting Expenses	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Meetings	$ 370,750	$ 370,750	$ 361,750	$ (9,000)	-2.4%
Travel	$ 845,900	$ 845,900	$ 845,900	$ -	0.0%
Conference Calls	$ 36,000	$ 36,000	$ 36,000	$ -	0.0%
Total Meeting Expenses	**$ 1,252,650**	**$ 1,252,650**	**$ 1,243,650**	**$ (9,000)**	**-0.7%**

Explanation of Significant Variances – 2020 Budget versus 2019 Budget

- None.

Table B-6 Consultants and Contracts

Consultants	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Consultants					
Reliability Standards	$ -	$ -	$ -	$ -	-
Compliance Enforcement and Organization Registration and Certification	$ -	$ -	$ -	$ -	-
Reliability Assessment and Performance Analysis	$ -	$ -	$ -	$ -	-
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ -	$ -	$ -	$ -	-
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ -	$ -	$ 279,000	$ 279,000	-
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ -	$ -	$ -	$ -	-
Consultants Total	**$ -**	**$ -**	**$ 279,000**	**$ 279,000**	**-**

Contracts	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Reliability Standards	$ 10,000	$ 10,000	$ 20,000	$ 10,000	100.0%
Compliance Enforcement and Organization Registration and Certification	$ 1,357,150	$ 1,357,150	$ 1,097,150	$ (260,000)	-19.2%
Reliability Assessment and Performance Analysis	$ 430,000	$ 430,000	$ 533,000	$ 103,000	24.0%
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ 130,000	$ 130,000	$ 60,000	$ (70,000)	-53.8%
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ 88,000	$ 88,000	$ 75,000	$ (13,000)	-14.8%
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ 7,000	$ 7,000	$ 7,000	$ -	0.0%
Contracts Total	**$ 2,022,150**	**$ 2,022,150**	**$ 1,792,150**	**$ (230,000)**	**-11.4%**
Total Consultants and Contracts	**$ 2,022,150**	**$ 2,022,150**	**$ 2,071,150**	**$ 49,000**	**2.4%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- During 2020 an executive search will be conducted in order to identify a successor CEO. Consulting costs related to the search efforts will be funded from the existing Business Continuity Reserves. 2020 assessments will not be impacted by these succession-related expenses.
- Ongoing effort to decrease the use of consultants and contractors when possible. (See program area sections for detail regarding a specific program area.)

Table B-7 Office Rent

Office Rent	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Office Rent	$ 650,000	$ 650,000	$ 650,000	$ -	0.0%
Utilities	$ 45,000	$ 45,000	$ 47,000	$ 2,000	4.4%
Maintenance	$ 37,000	$ 37,000	$ 37,000	$ -	0.0%
Security	$ 2,700	$ 2,700	$ 2,700	$ -	0.0%
Real Estate Taxes	$ 86,000	$ 86,000	$ 96,000	$ 10,000	11.6%
Total Office Rent	**$ 820,700**	**$ 820,700**	**$ 832,700**	**$ 12,000**	**1.5%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- None.

Table B-8 Office Costs

Office Costs	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Telephone	$ 88,720	$ 88,720	$ 88,720	$ -	0.0%
Internet Expense	$ 82,740	$ 82,740	$ 74,340	$ (8,400)	-10.2%
Office Supplies	$ 33,000	$ 33,000	$ 33,000	$ -	0.0%
Computer Supplies and Maintenance	$ 397,387	$ 397,387	$ 424,921	$ 27,534	6.9%
Subscriptions & Publications	$ 13,500	$ 13,500	$ 14,000	$ 500	3.7%
Dues	$ 3,400	$ 3,400	$ 3,400	$ -	0.0%
Postage	$ 1,200	$ 1,200	$ 1,200	$ -	0.0%
Express Shipping	$ 10,000	$ 10,000	$ 6,000	$ (4,000)	-40.0%
Copying	$ 26,400	$ 26,400	$ 26,400	$ -	0.0%
Reports	$ 8,000	$ 8,000	$ 2,000	$ (6,000)	-75.0%
Stationary and Office Forms	$ 2,000	$ 2,000	$ 2,000	$ -	0.0%
Equipment Repair/Service Contracts	$ -	$ -	$ -	$ -	-
Bank Charges	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Sales and Use Tax	$ -	$ -	$ -	$ -	-
Merchant Credit Card Fees	$ -	$ -	$ -	$ -	-
Presentation and Publicity	$ -	$ -	$ -	$ -	-
Total Office Costs	**$ 676,347**	**$ 676,347**	**$ 685,981**	**$ 9,634**	**1.4%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- Total Office costs are expected to remain relatively flat.

Table B-9 Professional Services

Professional Services	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
BOT Fee	$ 346,000	$ 346,000	$ 332,000	$ (14,000)	-4.0%
BOT Search Fee	$ -	$ -	$ -	$ -	-
Legal - Reorganization	$ -	$ -	$ -	$ -	-
Accounting & Auditing Fees	$ 300,000	$ 300,000	$ 310,000	$ 10,000	3.3%
Legal Fees - Other	$ 262,000	$ 262,000	$ 235,000	$ (27,000)	-10.3%
Insurance - Commercial	$ 70,000	$ 70,000	$ 70,000	$ -	0.0%
Total Services	**$ 978,000**	**$ 978,000**	**$ 947,000**	**$ (31,000)**	**-3.2%**

Table B-10 Miscellaneous

Miscellaneous Expense	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Miscellaneous Expense	$ 51,000	$ 51,000	$ 51,000	$ -	0.0%
Total Miscellaneous Expense	**$ 51,000**	**$ 51,000**	**$ 51,000**	**$ -**	**0.0%**

Table B-11 Other Non-Operating Expenses

Other Non-Operating Expenses	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Interest Expense	$ -	$ -	$ -	$ -	-
Office Relocation	$ -	$ -	$ -	$ -	-
Total Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**-**

Table B-12 Fixed Assets

Fixed Asset Additions	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Equipment CapEx	$ -	$ -	$ -	$ -	-
Computer & Software CapEx	$ 170,000	$ 170,000	$ 170,000	$ -	0.0%
Furniture & Fixtures CapEx	$ -	$ -	$ -	$ -	-
Leasehold Improvements	$ -	$ -	$ -	$ -	-
Allocation of Fixed Assets	$ -	$ -	$ -	$ -	-
Total Fixed Asset Additions	**$ 170,000**	**$ 170,000**	**$ 170,000**	**$ -**	**0.0%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- Capital expenditures planned for 2020 include the continuing implementation of the document management system and equipment upgrades.

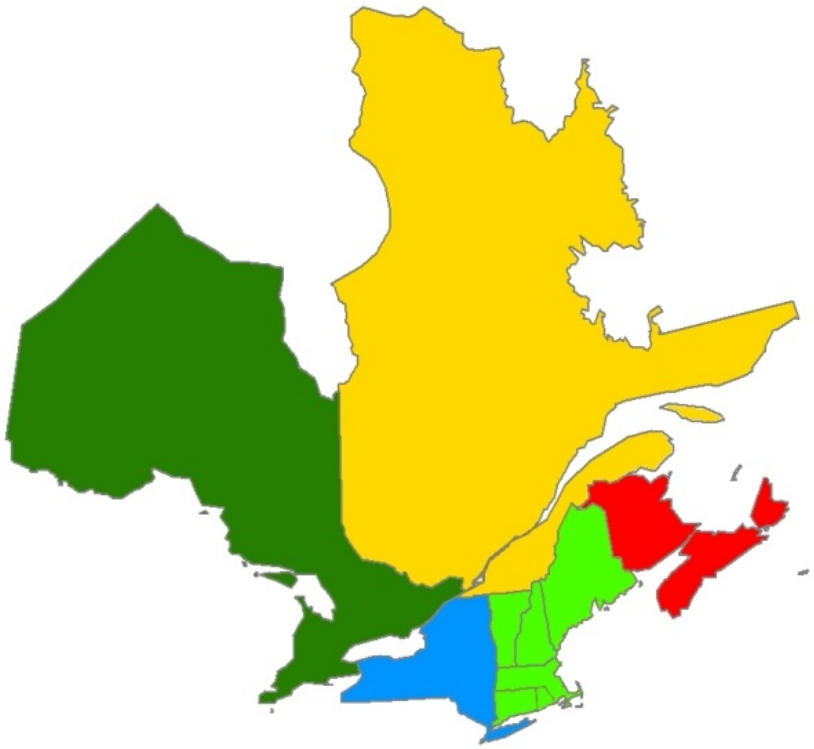
Table B-13 2020 and 2021 Projections

Table to be Inserted

Assumptions

Section C — Criteria Services Division Activities

2020 Business Plan and Budget



Section C – Criteria Services Division Activities

Criteria Services Division (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	2.14	2.16	0.02
Total Direct Expenses	$662,756	$709,217	$46,462
Total Indirect Expenses	$398,765	$409,450	$10,685
Other Non-Operating Expenses	$0	$0	$0
Working Capital and Operating Reserves Requirement	($32,655)	($79,265)	($46,611)
Fixed Asset Additions	$30,000	$30,000	$0
Funding Requirement	$1,058,866	$1,069,402	$10,536

NPCC Regionally-Specific Criteria Services Background

NPCC Criteria Services division activities are based on the development, maintenance (including retirement when no longer needed), and promulgation of new or revised Regionally-specific, more stringent reliability criteria and supporting guideline or procedural documents. The requirements in NPCC Reliability Criteria apply only to those facilities defined as NPCC Bulk Power System elements through the performance based methodology identified in the NPCC Document A-10, "Classification of Bulk Power System Elements."

In accordance with the NERC Rules of Procedure (RoP) Section 313, Regional Entities may develop Regional Criteria necessary to implement, augment, or facilitate compliance with NERC Reliability Standards. These Regional Criteria may also be utilized to address issues not within the scope or jurisdiction of FERC as outlined in Section 215 of the Federal Power Act, such as resource adequacy. Regional Criteria may also address Canadian Provincial reliability issues, and may include specific operating or planning parameters, guides, agreements, protocols or other documents used to enhance the reliability of the Bulk Power System in the Region. These documents typically provide benefits by promoting more consistent implementation of the NERC Reliability Standards within the Region. These documents are not NERC Reliability Standards, Regional Reliability Standards, or Regional Variances, and therefore are not enforceable under the authority delegated by NERC pursuant to delegation agreements.

As NERC Reliability Standards are revised or new standards are developed, NPCC performs reviews of any associated Regional Criteria for possible impact.

For 2020 and beyond, the potential reliability impacts of increased penetration of Distributed Energy Resources (DER, e.g. solar and wind), and changing fuel mixes warrant further consideration. The Criteria Services Division has a unique opportunity to review these issues and develop criteria, guideline, and procedural documents for DER which may be outside of the jurisdiction of FERC and NERC Reliability Standards. Participation of the entities responsible for development of DER renewable resources to develop reliability documents will become increasingly important over time. Outreach, collaboration, and coordination of topics related to DER will enable NPCC to develop guidelines allowing more effective integration of these resources.

Increasing resilience of the BPS through alternative approaches to standards development using potential NPCC criteria, guidelines, and whitepapers will also be continually reviewed by NPCC's body of subject matter experts.

Membership and Governance

Full members, in accordance with NPCC's Amended and Restated Bylaws, are subject to compliance with Regionally-specific criteria and receive criteria-related services from the Criteria Services division.

Full Members, aside from those who perform the Balancing Authority function, are not assessed an annual membership fee. Those that perform Balancing Authority functions are assessed and remit a proportional net energy for load share of expenses for Criteria Services. NPCC would also directly assign Criteria Service division costs to a Balancing Authority Area or entity, where significant costs are incurred for that Balancing Authority Area. The funding for NPCC's Criteria Services division is approved by the NPCC Board of Directors.

Under Criteria Services NPCC will identify for membership, those entities involved in emerging technologies to assure that those entities that have an impact on Bulk Electric System reliability are included in appropriate NPCC activities.

Criteria Services Division Functional Scope

Through its Criteria Services division, NPCC promotes the reliable and efficient operation of the international, interconnected bulk power systems in Northeastern North America through the establishment of Regionally-specific criteria, and monitoring and enforcement of compliance with such criteria.

NPCC provides Full Members with Regional reliability assurance services, and acts as the vehicle through which States and Provinces can fulfill their political mandates, with respect to resource adequacy, as well as overseeing the Northeastern North American electric infrastructure.

Major 2020 Assumptions and Cost Impacts

The Criteria Services division activities are expected to remain stable or slightly increase throughout 2020 depending on reliability need.

- The Criteria Compliance Enforcement Program (CCEP) review and evaluation process is the mechanism for monitoring key criteria attributes as determined by the respective NPCC Task Forces and the Compliance Committee.
- Past non-compliances, if any, followed the due process stated in the CCEP-1 process document and proper resolution/enforcement action taken.

2020 Primary Goals and Objectives

- Continue with the development and maintenance of a set of NPCC Directories which augment or add specificity to the NERC Reliability Standards and which clearly delineate the more stringent NPCC criteria requirements. The combination of North American and more stringent NPCC Regional criteria provide for consistency and operational clarity while providing more robust defense in–depth, results based, criteria requirements to ensure NPCC BPS reliability.
- Continually review the criteria found in the NPCC Directories and the ERO standards to ensure no redundancies or inconsistencies exist.

- Retire Directories and/or Criteria which have been overtaken by improved NERC standards.
    - Directory No. 12 "Automatic Underfrequency Load Shedding Requirements" will be retired in 2020 upon approval of PRC-006-NPCC-2 "Automatic Underfrequency Load Shedding" Regional Standard
- Identify opportunities to develop criteria, procedures or guideline documents to address reliability related matters with DER.
- Identify opportunities to address improvements in BES resilience with NPCC processes and documentation.
- Continually review the need to file revised and updated more stringent requirements with the New York State Department of Public Service and Canadian Provinces as applicable.
- Review, maintain, and revise the NPCC Regional Reliability Directories to facilitate compliance assessments and ensure the Criteria portions of the Directories augment and are not duplicative with, the approved and effective NERC Standards.
- The Criteria Services division and CCEP Working Group (reporting to the Compliance Committee) will work with the various Task Forces to develop Criteria Compliance Reporting Forms for any additional NPCC Directories to ensure that the more stringent or Regionally-specific criteria is being met.
- The Criteria Services division and CCEP working group will work with TFCO, TFCP, TFSS, and TFSP to review criteria and measures within each specific NPCC Directory to identify and develop them into specific reporting forms for approval.
- Continually review impact of Bulk Electric System definition on Directory and Criteria content and compliance reporting.
- Continually review potential impacts of Sector or NPCC organizational changes on the Directories and Criteria by performing a review of enforcement and arbitration processes as needed.
- Assist Legal with preparation of revised Directories for Regulatory filings with the individual Provinces in accordance with their respective Memorandum of Understandings (MOUs) as well as the State of New York Public Service Commission.
- Facilitate any requested clarifications for NPCC Criteria with the necessary subject matter experts and also identify any other potential opportunities for clarifications of the Criteria.
- Conduct review of the following Documents:
    - Directory No. 7 – *Special Protection Systems* – the TFSP will serve as lead Task Force working in conjunction with TFCP and TFSS on revisions required to ensure consistency with the development of the NERC standard on Remedial Action Schemes.
    -
    - Review and respond to Requests for Clarifications to existing NPCC Standards, Directories, and Criteria.

NPCC Reliability Directory Maintenance and Development

The NPCC Regional Reliability Directories were developed to demonstrate that the NPCC more stringent criteria augment, add specificity, or address issues not covered in the NERC Reliability Standards as mandated by the NERC Rules of Procedure. The conversion of NPCC's reliability criteria into Directories was undertaken to remove any redundancies with the NERC or NPCC Regional Reliability Standards and to clearly delineate the more stringent NPCC criteria requirements, assign Functional Model designations to those responsible for compliance and create measurable compliance criteria. Subsequent to the initial establishment of the Directories, which also organized functionally related B Guidelines and C Procedures into a single Directory, the Directories were further reviewed to translate existing criteria language into a requirements

and "standards type" format. The development of the criteria into NERC style requirements facilitates the NPCC Region's CCEP and also ensures the delineation of the more stringent and more specific Regional criteria from the latest approved and effective set of NERC ERO standards.

In 2020, work will continue with the maintenance, revision, or potential retirement of individual Directories to address any actual or anticipated redundancies with new or modified NERC or NPCC Reliability Standards. The ongoing review and maintenance of the Directories will require Task Force and Criteria Services staff to support this effort and to serve as subject matter experts. In addition to the ongoing review of the criteria within the Directories for potential duplicity with the NERC standards, any Directories that have not had the criteria translated into NERC style requirements will also be reviewed in order to achieve criteria 'requirements' which are clear, concise and measurable. Also, a standards style template will continue to be applied to the existing Directories to make them more consistent with the format of NERC standards. As NERC standards improve, the need for NPCC Directories and the amount of criteria contained therein may decrease over time, however in the interim, significant review is necessary to ensure the criteria remain consistent with the NERC standards as outlined in the NERC Rules of Procedure. NPCC will conduct internal reviews of all draft standards against Regional criteria and utilize subject matter experts to identify reliability and compliance related concerns. NPCC will file the revised NPCC Directories and notifications of retirements of Directories with the Canadian governmental and/or provincial Regulatory authorities within the NPCC "footprint", on an as needed basis, in accordance with established provincial procedures and agreements executed with NPCC.

Additionally, as NERC Reliablity Standards are developed, associated Directories will be reviewed for continued need. This review will identify the incremental reliability enhancement the Directory's criteria will yield, determine if the enhancement is sufficient to warrant retention and if so, are there any potential cost effective alternatives that may exist to achieve that enhanced level of reliablity.

NPCC Operations and Planning Directories

The following Directories are envisioned to remain active for 2020.

Directory #1, *Design and Operation of the Bulk Power System*.
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with all the existing NERC TPL, BAL, IRO, INT, MOD, TOP, PRC and VAR standards. The NPCC TFCP and TFCO completed a review of the Directory#1 criteria, during which the criteria was translated into NERC style requirements and revisions were enacted to ensure consistency with recent changes to the TPL and TOP standards.

Directory #2, *Emergency Operations*
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with all the existing NERC EOP and TOP standards. The NPCC Task Force on Coordination of Operation is reviewing this Directory in 2019.

Directory #4, *System Protection Criteria*
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with certain applicable NERC PRC standards. The NPCC Task Force on System Protection will lead this review and revision.

Directory #5, *Reserve*
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with all the existing applicable NERC BAL, INT, and IRO standards. The NPCC Task Force on Coordination of Operation will lead this review and revision and ensure consistency with the BAL standards.

Directory #7, *Special Protection Systems*
This Directory documents NPCC's Regionally-specific, more stringent criteria for application and approval of SPS. The NPCC Task Force on System Protection will lead this review and revision and ensure consistency with the Remedial Action Scheme PRC-012 standard.

Directory #8, *System Restoration*
This Directory documents NPCC's Regionally-specific, more stringent criteria with which each applicable entity must plan for and perform power system restoration following a major or a total blackout, and demonstrates coordination and consistency with applicable NERC EOP standards. The NPCC Task Force on Coordination of Operation lead the review and revision of this Directory in 2018. The Directory was re-formatted to be consistent with the style of NERC standards.

Directory #11, *Disturbance Monitoring Equipment*,
This directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with certain existing NERC PRC standards. The NPCC Task Force on System Protection anticipates the development and approval of Directory#11 in order to facilitate the retirement of PRC -002-NPCC-1 and will lead this review and revision.

NPCC Criteria Compliance and Enforcement Program (CCEP)

The NPCC Criteria Services division supports the reliable operation of the NPCC Bulk Power System (BPS) through implementation of the NPCC Criteria Compliance Program (CCEP). This program monitors, assesses, and enforces compliance on a subset of the regionally specific, more stringent NPCC Criteria that are unique to the NPCC BPS and are not duplicative of the NERC Reliability Standards. The physical characteristics and topology of the transmission system within the Region require that certain aspects of criteria be monitored for compliance.

The Criteria Services division and the NPCC Compliance Committee (CC) administer the CCEP. The CC is a stakeholder body consisting of NPCC Members and is structured by the seven sectors that appear in the NPCC Bylaws.

Noncompliance to NPCC Criteria is not subject to monetary sanctions and results in a notification of noncompliance to the Chief Executive Officer of the appropriate Full Member.

The CCEP program is described in document CCEP-1, *NPCC Criteria Compliance and Enforcement Program (CCEP) Process Document.* The CC reviews CCEP-1 annually and revisions to CCEP-1 are reviewed and approved by the CC.

The CCEP-1 document:

1. Provides a comprehensive CCEP Process Flow Diagram showing the process of evaluating and approving Criteria Certification submittals, and additional processes and responsibilities in the event that noncompliances, disputes, and sanctions arise;
2. Describes the roles and responsibilities of Reporting Members, the CC, the NPCC Reliability Coordinating Committee, and the Enforcement Panel in the compliance review and enforcement process
3. Describes non-monetary Sanctions, the Lateness Policy, and the Arbitration/Dispute Resolution process
4. Addresses the development of Mitigation Plans for any violations under the enforcement process

The CCEP Working Group (under the CC) develops a draft of the annual CCEP Implementation Plan and updates the blank certification templates for the upcoming Plan year. The Implementation Plan identifies the subset of Criteria that must be certified to and includes the certification form due dates. The draft CCEP Implementation Plan for the coming year and the draft certification templates are then submitted to the CC for review and approval.

The CC members review the completed certification forms that are returned by Full Members. NPCC Staff develops an assessment report and scorecard that summarizes the certifications that were received for the CC to review and approve. The assessment report and any recommendations on noncompliances are then presented to the NPCC Reliability Coordinating Committee (RCC) for approval.

Compliance to the NPCC Criteria is a responsibility of the NPCC Members and is codified in the *AMENDED AND RESTATED BYLAWS OF NORTHEAST POWER COORDINATING COUNCIL, INC.* Implementation of the CCEP is also consist with the current Memorandum of Understating that NPCC has with its Canadian Members.

Explanation of Significant Variances – 2020 Budget versus 2019 Budget

- None.

2019 Budget and Projection and 2020 Budget Comparisons

Statement of Activities and Capital Expenditures
2019 Budget & Projection, and 2020 Budget

CRITERIA SERVICES DIVISION

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ -	$ -	$ -	$ -	$ -
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Membership Dues	1,058,866	1,058,866	-	1,069,402	10,536
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 1,058,866**	**$ 1,058,866**	**$ -**	**$ 1,069,402**	**$ 10,536**
Expenses						
Personnel Expenses						
	Salaries	$ 371,938	$ 371,938	$ -	$ 367,979	$ (3,959)
	Payroll Taxes	23,696	23,696	-	24,864	1,168
	Benefits	102,779	102,779	-	123,261	20,482
	Retirement Costs	43,182	43,182	-	41,954	(1,228)
Total Personnel Expenses		**$ 541,596**	**$ 541,596**	**$ -**	**$ 558,057**	**$ 16,462**
Meeting Expenses						
	Meetings	$ 5,000	$ 5,000	$ -	$ 14,000	$ 9,000
	Travel	56,800	56,800	-	56,800	-
Total Meeting Expenses		**$ 61,800**	**$ 61,800**	**$ -**	**$ 70,800**	**$ 9,000**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 55,360	$ 55,360	$ -	$ 76,360	$ 21,000
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	4,000	4,000	-	4,000	-
Total Operating Expenses		**$ 59,360**	**$ 59,360**	**$ -**	**$ 80,360**	**$ 21,000**
	Total Direct Expenses	**$ 662,756**	**$ 662,756**	**$ -**	**$ 709,217**	**$ 46,462**
Indirect Expenses		**$ 415,818**	**$ 415,818**	**$ -**	**$ 409,450**	**$ (6,368)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,078,574**	**$ 1,078,574**	**$ -**	**$ 1,118,668**	**$ 40,094**
Change in Assets		**$ (19,707)**	**$ (19,707)**	**$ -**	**$ (49,265)**	**$ (29,558)**
Fixed Asset Additions (C)		**$ 30,000**	**$ 30,000**	**$ -**	**$ 30,000**	**$ -**
TOTAL BUDGET (=B+C)		**$ 1,108,574**	**$ 1,108,574**	**$ -**	**$ 1,148,668**	**$ 40,094**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (49,707)**	**$ (49,707)**	**$ -**	**$ (79,265)**	**$ (29,558)**

Personnel Analysis

Total FTE's by Program Area	Budget 2019	Projection 2019	Direct FTEs 2020 Budget	Shared FTEs1 2020 Budget	Total FTEs 2020 Budget	Change from 2019 Budget
CRITERIA SERVICES DIVISION						
Operational Programs						
Reliability Standards	1.07	1.07	1.00	0.08	1.08	0.01
Compliance Enforcement and Organization Registration and Certification	0.00	0.00	0.00	0.00	0.00	0.00
Training and Education	0.00	0.00	0.00	0.00	0.00	0.00
Reliability Assessment and Performance Analysis	1.07	1.07	1.00	0.08	1.08	0.01
Situation Awareness and Infrastructure Security	0.00	0.00	0.00	0.00	0.00	0.00
Total FTEs Operational Programs	**2.14**	**2.14**	**2.00**	**0.16**	**2.16**	**0.02**
Administrative Programs						
Member Forums	0.00	0.00	0.00	0.00	0.00	0.00
General and Administrative	0.00	0.00	0.00	0.00	0.00	0.00
Information Technology	0.00	0.00	0.00	0.00	0.00	0.00
Legal and Regulatory	0.00	0.00	0.00	0.00	0.00	0.00
Human Resources	0.00	0.00	0.00	0.00	0.00	0.00
Accounting and Finance	0.00	0.00	0.00	0.00	0.00	0.00
Total FTEs Administrative Programs	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Total FTEs	**2.14**	**2.14**	**2.00**	**0.16**	**2.16**	**0.02**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

Reserve Analysis 2019 - 2020

Working Capital and Operating Reserve Analysis 2019-2020
CRITERIA SERVICES DIVISION

	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Total Reserve, December 31, 2018	571,369	422,614	88,755	60,000
2019 Non-Statutory Funding (from members)	1,058,866	1,058,866		
Plus: 2019 Other funding sources	0	0		
Less: 2019 Projected expenses & fixed asset additions	(1,108,574)	(1,108,574)		
Projected Total Reserve, December 31, 2019	**521,661**	**372,906**	**88,755**	**60,000**
Desired Total Reserve, December 31, 2020	**442,396**	320,137 [1]	95,718 [2]	26,540 [3]
Less: Projected Total Reserve, December 31, 2019	(521,661)	(372,906)	(88,755)	(60,000)
Increase(decrease) in assessments to achieve desired Total Reserve	(79,265)	(52,769)	6,963	(33,460)

2020 Funding requirement for expenses and fixed asset additions	1,148,668
Less: Other Funding Sources	(4,200)
Less: Release of Business Continuity Reserve Funds [3]	(33,460)
Adjustment to Working Capital to achieve desired Total Reserve balance [2]	6,963
Adjustment to Operating Reserve to achieve desired Total Reserve balance [1]	(52,769)
2020 Funding and reserve requirement	1,065,202

[1] Total NPCC Operating Reserve must be within a range from 8.33% to 25.00% of Budget. $320,137 represents 27.87% of the 2019 CS budget of $1,148,668.

[2] Total NPCC Working Capital must equal 8.33% of Budget. $95,718 represents 8.33% of the 2019 CS budget of $1,148,668.

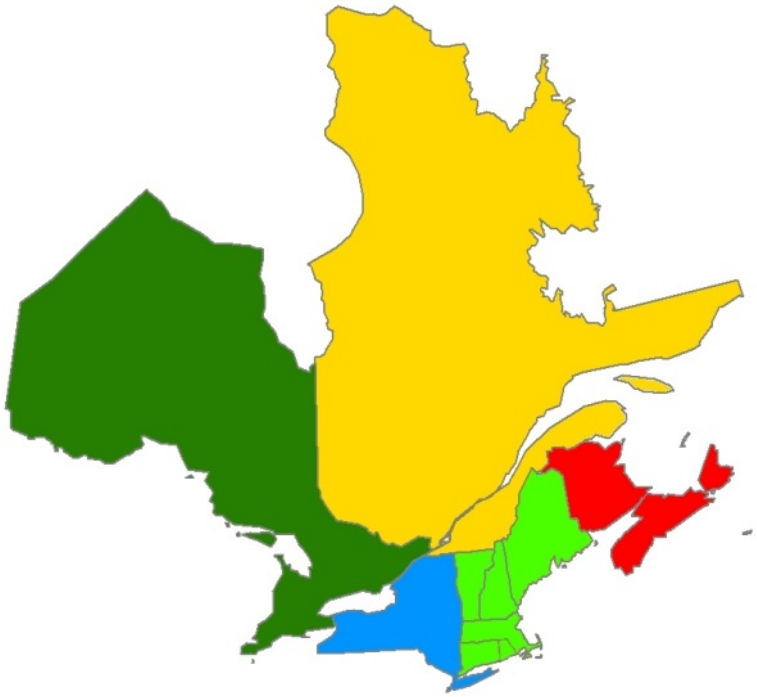
[3] Business Continuity Reserve (BCR) established in 2017 as approved by the NPCC Board of Directors to fund Succession Planning related expenses.

Explanation of Changes in Reserve Policy from Prior Year

There was no change to the existing Working Capital and Operating Reserve Policy. A separate Business Continuity Reserve (BCR) in the amount of $1,000,000 (allocated between the Regional Entity and Criteria Services divisions) was established in 2017 as approved by the NPCC Board of Directors, upon recommendation by the Management Development and Compensation Committee and endorsement by the Finance and Audit Committee, to be drawn upon as subsequently brought before the Board of Directors for approval of release of funds in association with President & CEO succession related activities associated with the planned or a sudden retirement, as well as other sudden changing workforce staffing requirements which could be brought about by coincident multiple staff retirements.

Section D – Additional Consolidated Financial Statements

2020 Business Plan and Budget



Section D — Additional Financial Statements

Statement of Financial Position

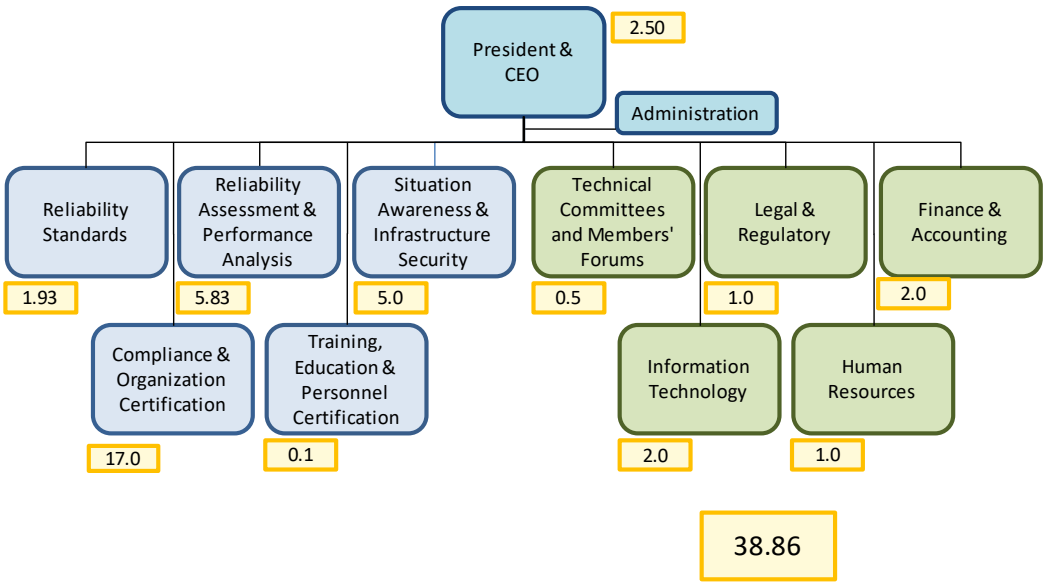
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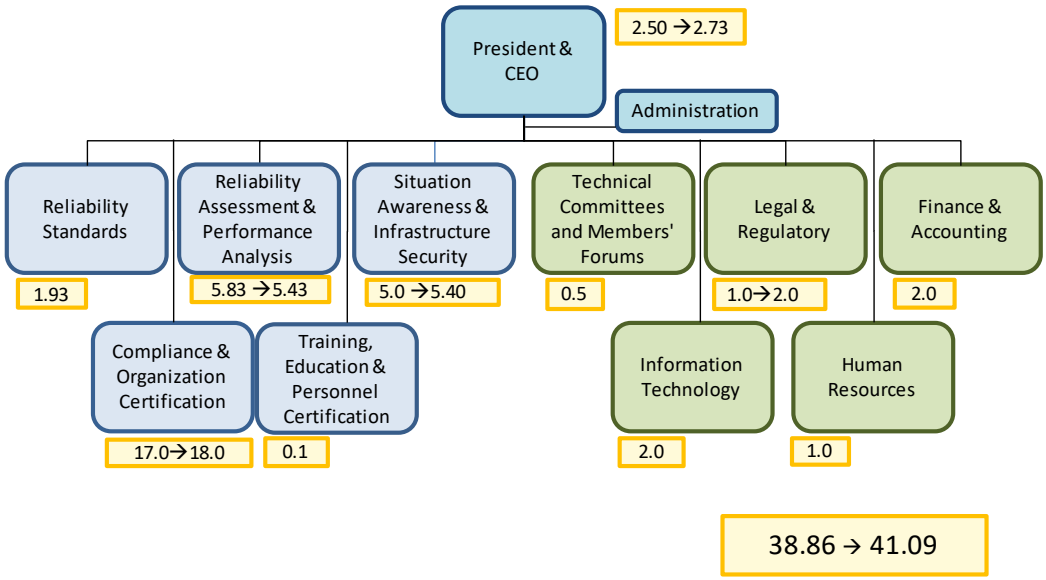
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Appendix A Staff Allocations

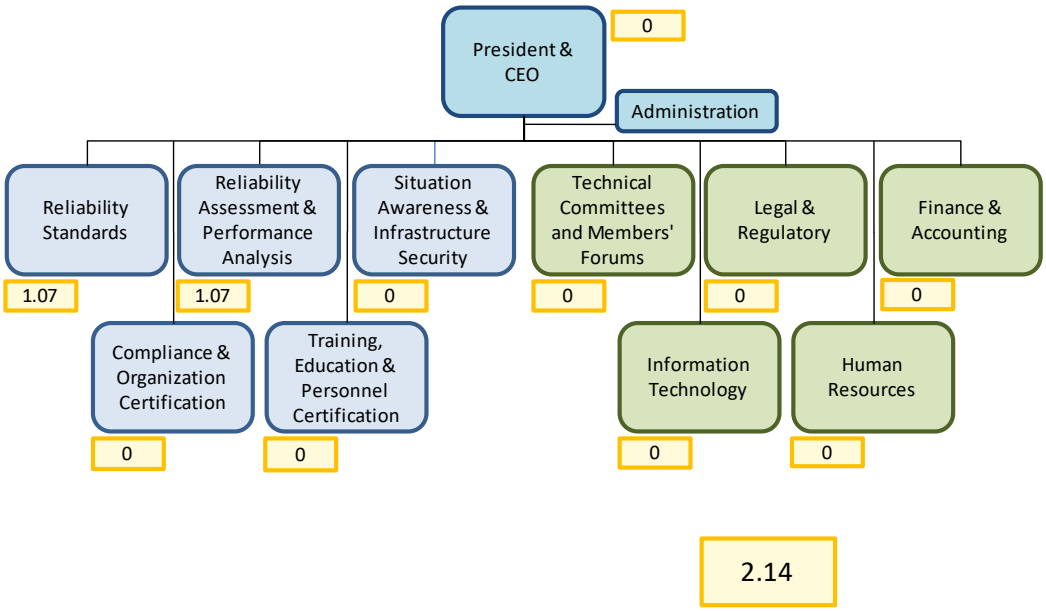
2019 Budget Staff Allocations - RE Division



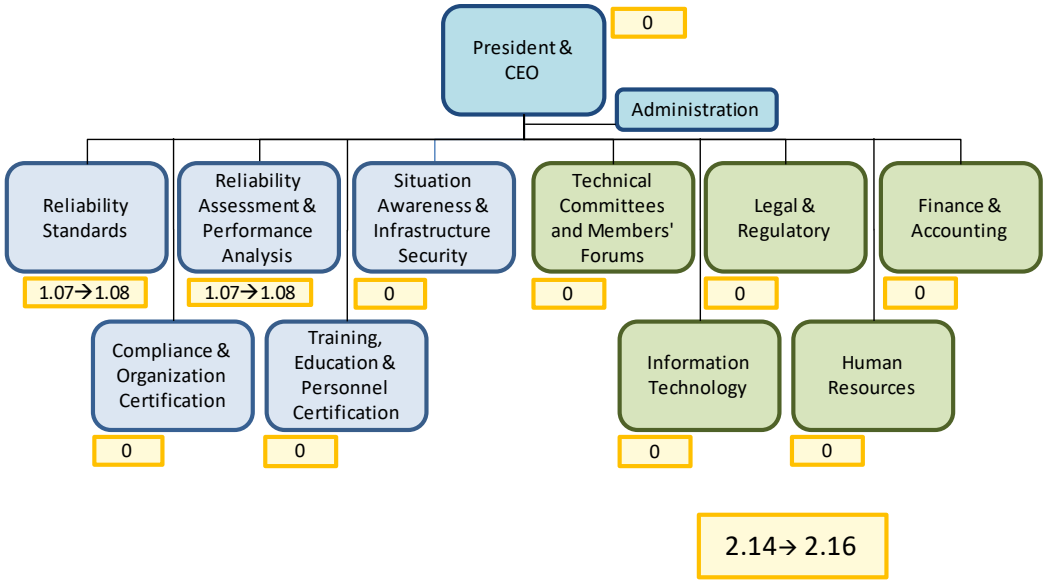
2020 Budget Staff Allocations - RE Division



2019 Budget Staff Allocations - CS Division



2020 Budget Staff Allocations - CS Division



Appendix B Acronyms

This section lists acronyms used in this document.

Acronym	Definition
AI	Audits and Investigations
BAA	Balancing Authority Area
BEPWG	BES Exception Process Working Group
BES	Bulk Electric System
BOT	Board of Trustees
BPS	Bulk Power System
CC	Compliance Committee
CCEP	Criteria Compliance Enforcement Program
CDAA	CMEP Data Administration Application
CEAP	Cost Effective Analysis Process
CEH	Continuing Education Hour
CGNC	Corporate Governance and Nominating Committee
CIPC	Critical Infrastructure Protection Committee
CIPIS	Critical Information Protection Information Sharing
CMEP	Compliance Monitoring and Enforcement Program
CORC	Compliance Monitoring and Enforcement and Organization Registration and Certification Program
CPP	Clean Power Plan
CRRA	Cost of Risk Reduction Analysis
CUG	Consortium Users Group
DADS	Demand Availability Data System
DADSWG	Demand Response Availability Data System Working Group
ERA	Entity Reliability Assessment
ERAG	Eastern Interconnection Reliability Assessment Group
ERO	Electric Reliability Organization
EUB	Electric Utility Board
EUB	Energy and Utilities Board
FAC	Finance and Audit Committee
FERC	Federal Energy Regulatory Commission
FFT	Find, Fix, Track
GADS	Generator Availability Data System
GADSWG	Generating Availability Data System Working Group
GMD	Geomagnetic Disturbance
HQCMÉ	Hydro-Québec Contrôle des mouvements d'énergie
HSIN	Homeland Security Information Network
ICE	Internal Controls Evaluation
IED	Intelligent Electronic Device
IERP	Independent Experts Review Panel Report
IESO	Independent Electricity System Operator
IRA	Inherent Risk Assessment
ISO	Independent System Operator
ITSG	IT Steering Group
LCEFT	Load, Capacity, Energy, Fuels, and Transmission
LMS	Learning Management System
LMWG	Load Modeling Working Group
LSE	Load Serving Entity
MACD	Market Assessment and Compliance Division of the IESO
MDCC	Management Development and Compensation Committee
ME	Mitigation and Enforcement
MMWG	Multi-Regional Modeling Working Group
MOU	Memorandum of Understanding
MPLS	Multiprotocol Label Switching
MVWG	Model Validation Working Group
NAESB	North American Electric Standards Review Board

Acronym	Definition
NEL	Net Energy for Load
NERC	North American Electric Reliability Corporation
NOAV	Notice of Alleged Violation
NOCV	Notice of Confirmed Violation
NOPR	Notice of Proposed Rulemaking
NOPV	Notice of Possible Violation
NPCC	Northeast Power Coordinating Council, Inc.
NRAP	NPCC Reliability Assessment program
NSPI	Nova Scotia Power Incorporated
NSUARB	Nova Scotia Utility and Review Board
OEB	Ontario Energy Board
PAS	Performance Analysis Subcommittee
PC	Pension Committee
PMOS	Project Management Oversight Subcommittee
PSMTF	Protection System Mis-operations Task Force
PSTN	Public Switched Telephone Network
QCMEP	Québec Reliability Standards Compliance Monitoring and Enforcement Program
RADS	Reliability Assessment Data System
RADWG	Reliability Assessment Data Working Group
RAS	Reliability Assessment Subcommittee
RC	Reliability Coordinator
RCC	Reliability Coordinating Committee
RISC	Reliability Issues Steering Committee
RSAW	Reliability Standards Audit Worksheet
RSC	Regional Standards Committee
RTO	Regional Transmission Organization
SAFNR	Situational Awareness-FERC, NERC, Regions
SAMS	System Analysis and Modeling Subcommittee
SAR	Standards Authorization Request
SAT	Systematic Approach to Training
SBS	Standards Balloting System
SCPS	Standards Committee Process Subcommittee
SDT	Standards Drafting Team
SEDS	Spare Equipment Database System
SEDTF	Spare Equipment Database Task Force
SPS	Special Protection Systems
TADS	Transmission Availability Data System
TADSWG	Transmission Availability Data System Working Group
TFCO	Task Force on Coordination of Operation
TFCP	Task Force on Coordination of Planning
TFE	Technical Feasibility Exception
TFIST	Task Force on Infrastructure Security and Technology
TFSP	Task Force on System Protection
TFSS	Task Force on System Studies
TLR	Transmission Loading Relief
TOP	Transmission Operator
UFLS	Underfrequency Load Shedding
UVLS	Under-Voltage Load Shedding
VRF	Violation Risk Factor
VSL	Violation Security Level

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

Draft

NPCC Guidance Document, An Approach for Distributed Energy Resources (DER) on Distribution Systems



NPCC Regional Standards Committee
Version 1 XXX XX, 2019

NPCC, Inc.

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

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Executive Summary

The Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America.

As Distributed Energy Resources (DER), installed on the distribution system, continue to replace traditional industry generation resources this transformation will impact the reliability and resilience of the Bulk Electric System (BES). Historically, the North American Electric Reliability Corporation (NERC) Reliability Standards have not been applicable to equipment on the distribution system unless such equipment has a direct impact on the reliable operation[1] of the BES; however as penetration of DER increases planning and operating assessments will need to accurately represent how DER interacts with the load characteristics of the distribution system. Development of this document was initiated by the NPCC Board of Directors to develop Regional guidance and suggested approaches to assist NPCC Members in modelling assessments for the operation and planning of DER within the NPCC Region. This initial guidance does not consider specific rooftop solar or individual installations of wind turbines or other localized behind the revenue meter DER. (although there is process described in this document which allows entities to identify impacts to NPCC so they can be addressed and acknowledged). NPCC Staff has developed this guidance as an initial document to leverage existing interconnection requirements at the distribution level and identify opportunities and potential gaps that may exist in order to promote good utility interconnection practices beneficial to reliability of the NPCC Region.

DER for the purpose of this guidance means any non-BES real or reactive resource (generating unit, multiple generating units at a single location, distributed generation, battery storage, etc.) located within the boundary of any distribution utility and not behind revenue metering, unless specifically indicated.

Introduction and Objective

As DERs continue to penetrate the electric system at the “grid edge” or distribution system, and replace conventional transmission grid connected carbon producing and nuclear generation resources, there is an increasing reliability related need to understand the effect of these DER resources. It is important to understand how DERs are interconnected, planned, operated and how they interact with the transmission grid. Reliably and securely integrating DER into the electric system will require a comprehensive approach utilizing perspectives from areas, such as, DER design, modeling, planning, relay coordination, and operations as well as consideration of regulatory and jurisdictional issues from both a U.S. and Canadian perspective. Appendix B of this document provides a comparison of NPCC’s Area requirements to help identify opportunities for guidance.

[1] Reliable Operation is defined in 16 U.S. Code § 824o and means “operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”

DERs are capable of bringing a number of enhancements to reliability. As an example, inverters, which convert direct current to alternating current, have microprocessor based control systems. These microprocessors operate with a very high internal clock speed (on the order of MHz) and are capable of fine resolution frequency measurement and electronically controlling the upward ramping of DER output and downwards ramping of DER output potentially ceasing the injection of current into the electric system at very high speeds depending on control decisions. Inverters are capable of remaining physically connected (breaker closed) and not injecting current well within normal 3-5 cycle breaker clearing times. This type of response can provide significant reliability benefits if control systems are properly configured to reliably implement it. Additionally, for upward ramping, the distribution level connected resource must be available and operate with the "headroom." In order to realize the benefits which DER are capable of to enhance reliability it is important to understand the hosting capacity of the distribution system feeders where they are being located and the DER's expected capabilities, capacity, and operation. In addition to improving system response, DER will enhance Resilience by decentralizing generation and affording flexibility during restoration beyond that of normal system restoration plans.

While DERs present opportunities to enhance reliability, they also introduce challenges at the transmission/distribution interface. Interoperability with the transmission system is not solely determined at the point of interconnection. System needs such as visibility of generation state is essential for transmission operators to maintain situational awareness for operations purposes, for forecasting and integrated system planning to ensure reliability is maintained. Presently there are no study tools in general use to perform fully integrated studies of transmission and distribution which would allow both systems to be modeled and studied (in steady state and dynamically) together, although work is underway in this regard.

In recognition of both benefits and challenges, the approach taken with this first NPCC DER guidance document was to collect interconnection requirements within the NPCC Region as well as in other areas of the NERC Electric Reliability Organization (ERO) Enterprise. There are some specific issues where opportunity exists to ensure coordination across the NPCC Region. The intent of this document is to identify risks and establish guidance, where possible, for interconnection of DER. NPCC will leverage existing requirements and proposed modifications for processes for a NPCC Region-wide approach to interconnecting DER to distribution systems and reliably operating DER in conjunction with the BES. It must be recognized that DERs may not be placed optimally and in areas where deliverability to load may not be ideal. In this respect any specific recomendations in this document will be subject to the requirements of the interconnecting distribution utility.

NPCC Reliability Principles

Using its membership structure and governance authority to create and apply Regional Criteria[2], NPCC Member adherence to Regional criteria contributes to a more robust level of reliability beyond NERC

[2] See NERC Rule of Procedure #313 on page 15 of the NERC Rules of Procedure 3-9-2018.

ERO reliability "results-based" standards / requirements. For example, NPCC Criteria mandate specific design requirements for assets in NPCC Member facilities. NPCC's approach to reliability and resilience can be summarized in Principles that guide NPCC Members in their effort to meet or exceed NERC requirements. NPCC's core Reliability Principles and supporting activities support the NERC Bulk Electric System and NPCC's Bulk Power System reliability.

Also recognized is the critical role that DER will have with respect to reliability and resilience of the Bulk Electric System. Specifically, DER can contribute to the Robustness of the system and provide increased resource support within islands during any system separations. As DER continues to penetrate the system changes to NPCC's Underfrequency Load Shedding program may be required.

The NPCC Reliability Principles include:

1. **Focus on the most important system components**: In order to focus resources to those portions of the power delivery system most important (critical) to overall reliability, NPCC Members employ mechanism(s) for identifying those facilities that are most critical to the reliable planning and operation of the power delivery assets in the NPCC region[3]. These critical facilities collectively are identified as the NPCC Bulk Power System[4][5].
2. **Application of Criteria beyond NERC requirements to identified critical facilities**: Where, in the opinion of NPCC's Membership, the NERC standards do not adequately specify a necessary performance or design outcome in a given technical, operation or planning area, NPCC Criteria govern the design of their respective portions of the NPCC Bulk Power System planning and operation[6] activities.
3. **NPCC Members support the Criteria**: NPCC's Full Members in accordance with the NPCC Bylaws are committed to designing and operating their systems to meet the NPCC Criteria under peer review of the NPCC Full Members.
4. **No conflict with NERC Requirements**: The NPCC Criteria supplement, improve upon where necessary, benefit, and do not conflict with or duplicate the results-based performance requirements of NERC standards where they apply to the NPCC Bulk Power System. NPCC

[3] The method of identifying critical facilities is currently embodied in the NPCC A-10 Classification of Bulk Power System Elements document, currently under review by the CP-11 Working Group with a due date of October 31, 2018.

[4] The NPCC Bulk Power System is identified by a specific list of facilities in the NPCC region deemed critical by the NPCC A-10 classification process. This list is not determined based on the definition of the ERO Bulk Power System, which is defined in the US 2005 EPACT as:

''(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and

''(B) electric energy from generation facilities needed to maintain transmission system reliability.

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

[5] There are other documents which supplement the Directories, for instance the NPCC Compliance Guidance Statements. These documents usually refer to NERC standards applicability and can be found here: NPCC CGS

[6] NERC Rule of Procedure #313 (page 15) permits the following: "Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy. "

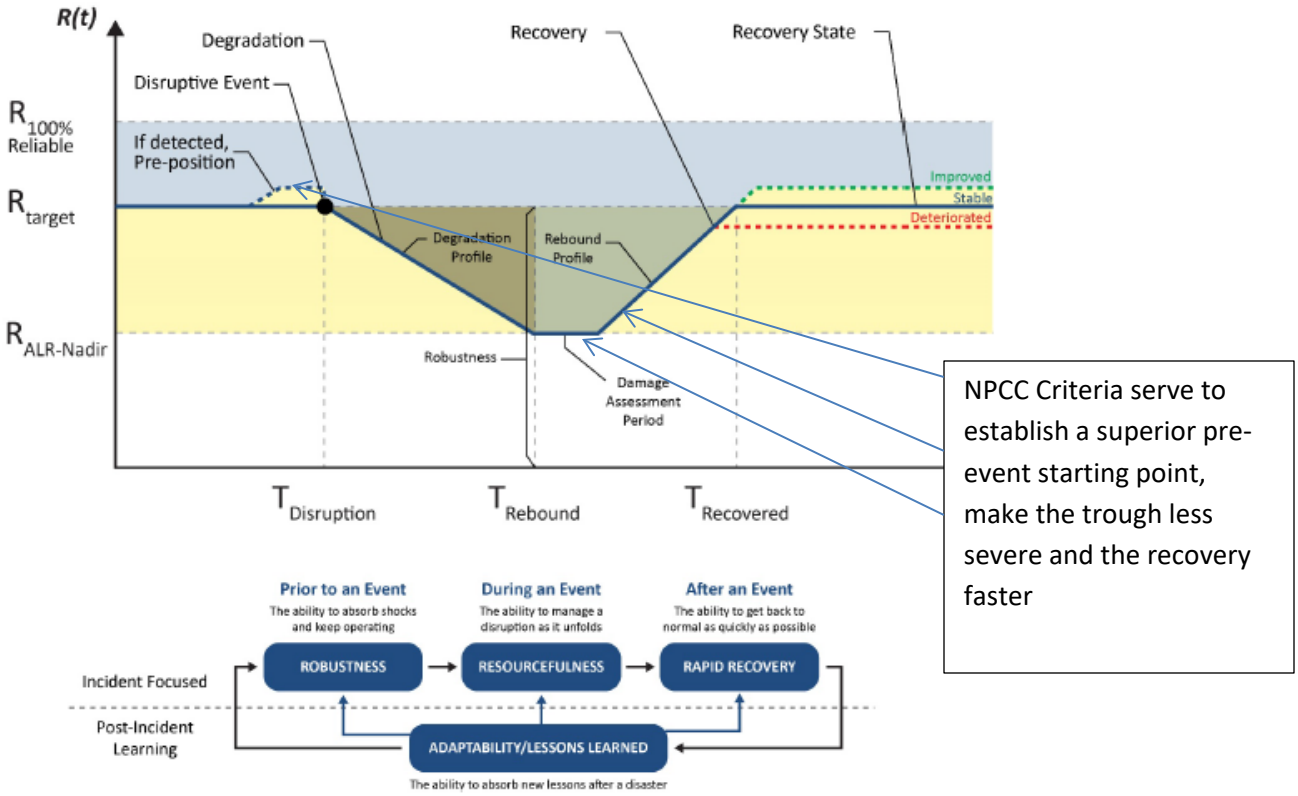
adjusts its regional Criteria to retire or adapt to any new NERC requirements as they come into effect as necessary.

5. **Include design specifications where needed**: The NPCC Criteria and related guidelines and procedures provide design criteria and practices to assure implementation. NPCC Directories go into greater detail regarding how to accomplish a given reliability result, where NERC standards may simply require a "reliability result."
6. **Resilience has always been an element of NPCC Criteria:** Based on experience, resilience[7] [8] is a necessary constituent component of reliability and it is important both to electricity consumers and regulatory authorities in NPCC's Region. NPCC Criteria provide substantial resilience benefits to the NPCC bulk power system by providing:
    a. Robustness – The ability to withstand disturbances by supporting operations in a more secure state.
    b. Resourcefulness – The ability to detect and manage a crisis as it unfolds.
    c. Rapid recovery – The ability to get services back as quickly as possible in a coordinated and controlled manner.
    d. Adaptability – The ability to absorb new lessons from events.

[7] Reference NERC's recent filing with FERC regarding Resilience for a more complete discussion of the relationship between resilience, the NERC standards and the NAICS Resilience Framework. FERC is expected to define resilience in the course of its current examination of electric system resilience concepts.

[8] In the US, Presidential Policy Directive – 21 defines resilience as "The ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents".

NERC RISC Proposed Model of Resilience



NPCC Criteria serve to establish a superior pre-event starting point, make the trough less severe and the recovery faster

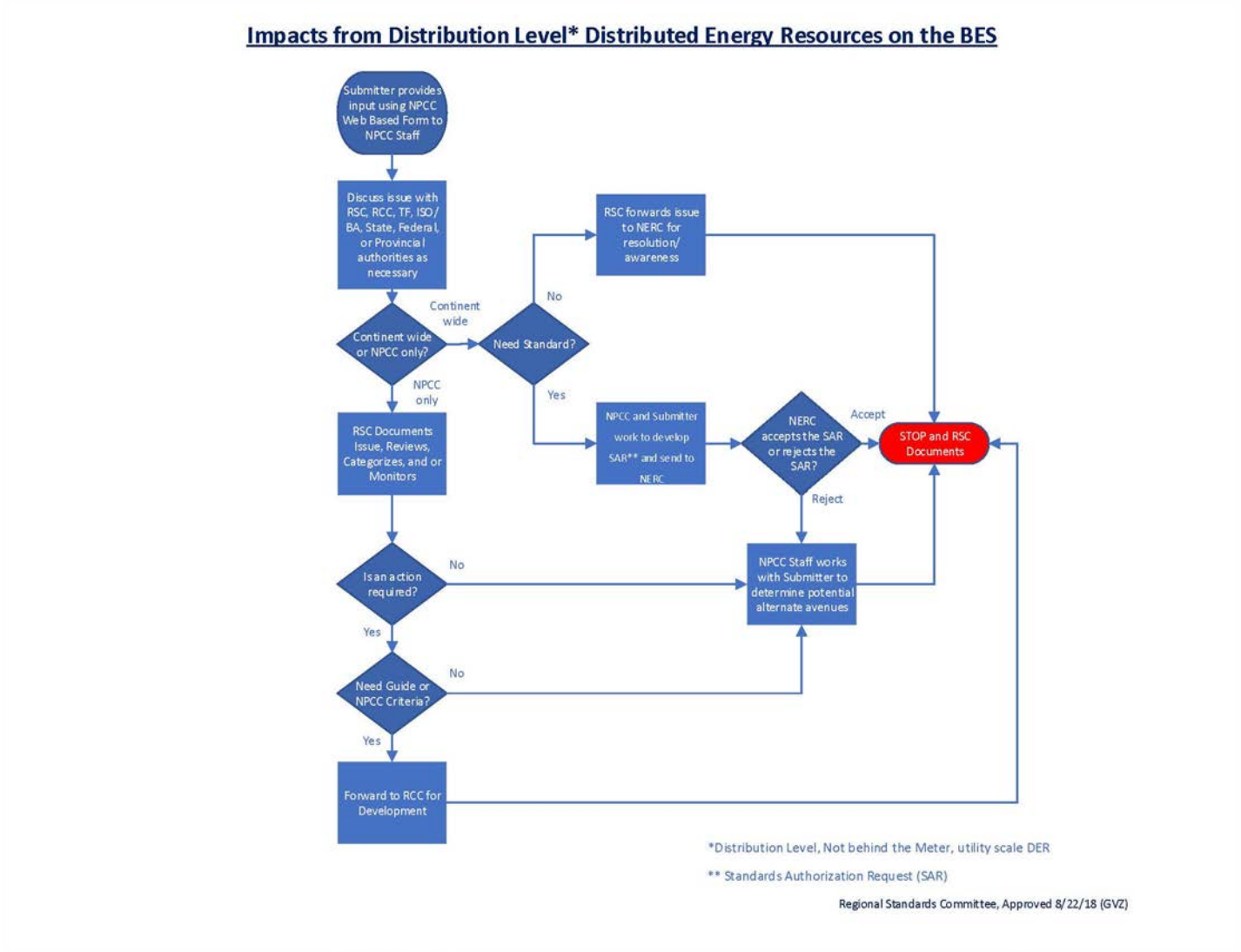
Figure 2.1

NPCC DER Impact Reporting

In order to ensure the reliability of the interconnected bulk power system in Northeastern North America as DER continues to proliferate throughout the distribution systems within the NPCC Region, it is important to have a centralized DER impact reporting mechanism. The NPCC Regional Standard Committee (RSC) created an impact reporting form and process that allows entities to report DER impacts and to seek guidance regarding emerging issues and reliability risks that affect or could affect the reliable performance of the Bulk Electric System (BES) see Appendix A. The Word version of the below form resides on the NPCC website at:

BES Impact Reporting Form

Impact reporting and associated process provide an orderly mechanism to review reliability impacts submitted to NPCC which is a collaborative review by the Reliability Coordinating Committee and Regional Standards Committee. The process is shown below.



DER BES Impact Considerations

NPCC's Regional Standards Committee and Task Force review of DER as it pertains to the NPCC Region's BES performance has identified a number of areas which, going forward, may warrant further and continual monitoring and analysis. NPCC has identified the following items that should be carefully tracked as DER levels (total MWs) increase.

- DER performance with respect to voltage and frequency ride through as well as the ability to provide regulation and reserves need to be consistent with the specifications of resources on the BES.
- DER availability and quality of forecasting to determine interoperability and day-ahead commitment.
- Observability: System operators must have sufficient situational awareness of DER to reliably operate the BES.

- Increasing penetration of DER will eventually affect Underfrequency Load Shed programs.
- Effect of Non-linear devices such as inverters producing harmonics on the power system.
- Impact of increasing DER on System Restoration and Black Start Plans.
- DER Markets: Encouraging Points of Common Coupling and injection to where it is best utilized and at appropriate levels.

NPCC Interconnection Guidance

The DER owner must be prepared to provide appropriate protection and control equipment, including a protective device and communications system that utilizes an automatic disconnecting device which will disconnect the generation under various conditions. For example in the event that the portion of the utility system that serves the generator is de-energized for any reason or for a fault in the generator-owner's system. There is also the possibility of over generation as has been demonstrated in CA, when the system operator runs out of load to absorb the available generation. Operating procedures for selecting which generation to curtail need to be in place. Some areas of the country are planning to use market mechanisms to address this issue. The DER owner's protection and control equipment also shall be capable of automatically disconnecting the generation from the system to which it is connected upon detection of a utility system fault.

The type and size of the generation facility or energy storage system is based on electrical generator or inverter AC nameplate rating.

The DER owner's protection and control scheme must be designed to ensure that the generation remains in operation when the frequency and voltage of the utility system is within the limits specified by the required operating ranges. Upon request from the utility, the DER owner shall provide documentation detailing compliance with the requirements set forth in this document.

The specific design of the protection, control, and grounding schemes will depend on the size and characteristics of the DER owner's generation, as well the DER owner's load level, in addition to the characteristics of the particular portion of the utility's system where the DER owner is interconnecting.

The DER owner should have, as a minimum, an automatic disconnect device(s) sized to meet all applicable local, state, and federal codes and operated by over and under voltage and over and under frequency protection. For three-phase installations, the over and under voltage function should be included for each phase and the over and under frequency protection on at least one phase. All phases of a generator or inverter interface shall disconnect for voltage or frequency trip conditions sensed by the protective devices. Voltage protection shall be wired phase to ground for single phase installations and for applications using wye grounded-wye grounded service transformers.

The settings below are listed for single-phase and three-phase applications using wye grounded- wye grounded service transformers or wye grounded-wye grounded isolation transformers. For applications using other transformer connections, a site-specific review will be performed by the utility and the revised settings identified in Step 6 of the Application Process.

The requirements set forth in this document are intended to be consistent with those contained in the most current version of IEEE Standard 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems. The requirements in IEEE 1547 above and beyond those contained in this document shall be followed and any other Standards included in or referenced to in IEEE Std. 1547 shall be adhered to.

Voltage Response

Operating range for the generators should be from 0.88 to 1.10 per unit of nominal voltage magnitude. In addition, the generator should not cause the system voltage at the Point of Common Coupling (PCC) to deviate from a range of 0.95 to 1.05 per unit of the utility system voltage. For excursions outside these limits the protective device should automatically initiate a disconnect sequence from the utility system as detailed in the most current version of IEEE Std. 1547. Clearing time is defined as the time the range is initially exceeded until the DER owner's equipment ceases to energize the PCC and includes detection and intentional time delay. Other static or dynamic voltage functionalities shall be permitted as agreed upon by the utility and DER owner.

Frequency Support

Frequency support is provided through the combined interactions of synchronous inertia and frequency response. Working in a coordinated way, these characteristics and services arrest the decline in frequency and eventually return the frequency to the desired level. As increased levels of DER are introduced to the system synchronous inertia will be displaced. Future work in the study of inertia on both an interconnection-wide and local basis will certainly be done in the future.

The operating range for the DER distribution connected resources should be similar to that of BES connected resources. The operating band for frequency of a DER resource's operating range should be at least from 59.3 Hz to 60.5 Hz as required by NPCC and NERC UFLS standards. If deemed necessary, due to abnormal system conditions, the utility may request that the generator operate at frequency ranges below 59.3 Hz in coordination with the current under frequency load shedding schemes of NPCC and the local utility system. For excursions outside these limits the protective device shall automatically initiate a disconnect sequence from the utility system as detailed in the most current version of IEEE 1547. Clearing time is defined as the time the range is initially exceeded until the DER owner's equipment ceases to energize the PCC and includes detection and intentional time delay. Other static or dynamic frequency functionalities shall be permitted as agreed upon by the utility and DER owner.

Reconnection to the Utility System

If the generation facility is disconnected as a result of the operation of a protective device, the DER owner's equipment shall remain disconnected until the utility's service voltage and frequency have recovered to acceptable voltage and frequency limits as defined in the most current version of IEEE Std. 1547 for a minimum of five (5) minutes. Systems greater than 25 kW that do not utilize inverter based interface equipment shall not have automatic recloser capability unless otherwise approved by the utility. If the utility determines that a facility must receive permission to reconnect, then any automatic reclosing functions must be disabled and verified to be disabled during verification testing.

Utilities in other parts of the Eastern Interconnection who have experienced increased levels of DER have determined that during system restoration, DER should not be allowed to return to service until the system has been reestablished and is in a stable operating state. As traditional resources on the BES are retired and the grid is will be increasingly reliant on grid edge DER on the distribution, Black Start and System Restoration plans will have to be adjusted accordingly.

Inverters

Direct current generation can only be installed in parallel with the utility's system using a synchronous inverter. The design shall be such as to disconnect the synchronous inverter upon a utility system event. Inverters intended to provide local grid support during system events that result in voltage and/or frequency excursions as described in this document and shall be provided with the required onboard functionality to allow for the equipment to remain online for the duration of the event.

All applicable inverter-based applications shall:

- be certified per the requirements of UL 1741 SA as a grid support utility interactive inverter
- have the voltage and frequency trip settings as specified by the interconnecting utility
- have the abnormal performance capabilities (ride-through)
- comply with other grid support utility interactive inverter functions statuses

It is recommended that equipment be selected from the Department of Public Service "Certified Interconnection Equipment list" maintained on the Commission's website. Interconnected DG systems utilizing equipment not found in such list must meet all functional requirements of the current version of IEEE Std 1547 and be protected by utility grade relays (as defined in these requirements) using settings approved by the utility and verified in the field. The field verification test must demonstrate that the equipment meets the voltage and frequency requirements detailed in this section.

Synchronization or re-synchronization of an inverter to the utility system shall not result in a voltage deviation that exceeds the requirements contained in Section II.E, Power Quality. Only inverters designed to operate in parallel with the utility system shall be utilized for that purpose.

Certification per UL 1741 SA as grid support utility interactive inverters

In the interim period while IEEE P1547.1 is not yet revised and published, certification of all inverter-based applications:

- Shall be compliant with only those parts of Clause 6 (Response to Area EPS abnormal conditions) of IEEE Std 1547-2018 (2nd ed.)1 that can be certified per the type test requirements of UL 1741 SA (September 2016). IEEE Std. 1547-2018 (2nd ed.) in combination with this document replaces other Source Requirements Documents (SRDs), as applicable;
- May be sufficiently achieved by certifying inverters as grid support utility interactive inverters per the requirements of UL 1741 SA (September 2016) with either CA Rule 21 or Hawaiian Rule 14H as the Source Requirement Document (SRD). Such inverters are deemed capable of meeting the requirements of this document.
- Applications should have the voltage and frequency trip points specified in Tables I and II below.

- Abnormal performance capability (ride-through) requirements for inverter based applications shall have the ride-through capability per abnormal performance category II of IEEE Std 1547-2018 (2nd ed.) as quoted in Tables III and IV.

The following additional performance requirements shall apply for all inverters:

- In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and
- In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode.

Table I: Inverters' Voltage Trip Settings (ISO-NE Tech Bulletin)

Shall Trip – IEEE Std 1547-2018 (2nd ed.) Category II					
Shall Trip Function	**Required Settings**		**Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category II**		
	Voltage (p.u. of nominal voltage)	**Clearing Time(s)**	**Voltage**	**Clearing Time(s)**	**Within ranges of allowable settings?**
OV2	1.20	0.16	Identical	Identical	Yes
OV1	1.10	2.0	Identical	Identical	Yes
UV1	0.88	2.0	Higher (default is 0.70 p.u.)	Much shorter (default is 10 s)	Yes
UV2	0.50	1.1	Slightly higher (default is 0.45 p.u.)	Much longer (default is 0.16 s)	Yes

Table II: Inverters' Frequency Trip Settings

Shall Trip Function	**Required Settings**		**Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category I, Category II, and Category III**		
	Frequency (Hz)	**Clearing Time(s)**	**Frequency**	**Clearing Time(s)**	**Within ranges of allowable settings?**
OF2	62.0	0.16	Identical	Identical	Yes
OF1	61.2	300.0	Identical	Identical	Yes
UF1	58.5	300.0	Identical	Identical	Yes
UF2	56.5	0.16	Identical	Identical	Yes

Table III: Inverters' Voltage Ride-through Capability and Operational Requirements

Voltage Range (p.u.)	Operating Mode/ Response	Minimum Ride-through Time(s) (design criteria)	Maximum Response Time(s) (design criteria)	Comparison to IEEE Std 1547-2018 (2nd ed.) for Category II
V > 1.20	Cease to Energize	N/A	0.16	Identical
1.175 < V ≤ 1.20	Permissive Operation	0.2	N/A	Identical
1.15 < V ≤ 1.175	Permissive Operation	0.5	N/A	Identical
1.10 < V ≤ 1.15	Permissive Operation	1	N/A	Identical
0.88 ≤ V ≤ 1.10	Continuous Operation	infinite	N/A	Identical
0.65 ≤ V < 0.88	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: $T_{VRT} = 3\text{ s} + \frac{8.7\text{ s}}{1\text{ p. u.}}(V - 0.65\text{ p.u.})$	N/A	Identical
0.45 ≤ V < 0.65	Permissive Operation [a,b]	0.32	N/A	See footnotes a & b
0.30 ≤ V < 0.45	Permissive Operation [b]	0.16	N/A	See footnote b
V < 0.30	Cease to Energize	N/A	0.16	Identical

The following additional operational requirements shall apply for all inverters:

a. In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and

b. In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode with a maximum response time of 0.083 seconds.

Table IV: Inverters' Frequency Ride-through Capability

Frequency Range (Hz)	Operating Mode	Minimum Time(s) (design criteria)	Comparison to IEEE Std 1547-2018 (2nd ed.) for Category II
f > 62.0	No ride-through requirements apply to this range		Identical
61.2 < f ≤ 61.8	Mandatory Operation	299	Identical
58.8 ≤ f ≤ 61.2	Continuous Operation	Infinite	Identical
57.0 ≤ f < 58.8	Mandatory Operation	299	Identical
f < 57.0	No ride-through requirements apply to this range		Identical

Table V: Grid Support Utility Interactive Inverter Functions Status

Function	Default Activation State
SPF, Specified Power Factor	OFF[2]
Q(V), Volt-Var Function with Watt or Var Priority	OFF Default value: 2% of maximum current output per second
SS, Soft-Start Ramp Rate	ON
FW, Freq-Watt Function OFF	OFF

Minimum Protective Functions

Protective system requirements for distributed generation facilities result from an assessment of many factors, including but not limited to:

• Type and size of the distributed generation facility

• Voltage level of the interconnection

• Location of the distributed generation facility on the circuit

Distribution transformer

• Distribution system configuration

• Available fault current

• Load that can remain connected to the distributed generation facility under isolated conditions

• Amount of existing distributed generation on the local distribution system.

It is not possible to standardize protection requirements according to any single criteria. Minimum protective function requirements shall be as detailed in the Table VI below. Function numbers, as detailed in the latest version of ANSI C37.2, are listed with each function. All voltage, frequency, and clearing time set points shall be field adjustable.

Table VI: Grid Support Minimum Protective Functions

Synchronous Generators	Induction Generators	Inverters
Over/Under Voltage (Function 27/59)	Over/Under Voltage (Function 27/59)	Over/Under Voltage (Function 27/59)
Over/Under Frequency (Function 81O/81U)	Over/Under Frequency (Function 81O/81U)	Over/Under Frequency (Function 81O/81U)
Anti-Islanding Protection	Anti-Islanding Protection	Anti-Islanding Protection
Overcurrent (Function 50P/50G/51P/51G)	Overcurrent (Function 50P/50G/51P/51G)	Overcurrent (Function 50P/50G/51P/51G)

For energy storage systems or distributed generation where net export is limited, Reverse Power (Function 32) should be required.

The need for additional protective functions will be determined by the utility on a case- by-case basis. If the utility determines a need for additional functions, it will notify the DER owner of the requirements.

The notice should include a description of the specific aspects of the utility system that necessitate the addition, and ideally, explicit justification for the necessity of the enhanced capability. The connecting utility will specify and provide settings for those functions that the utility designates as being required to satisfy their individual protection practices. Any protective equipment or setting specified by the utility must not be changed or modified at any time by the DER owner without consent from the utility.

The DER owner shall be responsible for ongoing compliance with all applicable local, state, and federal codes and standardized interconnection requirements as they pertain to the interconnection of the generating equipment. Protective devices shall utilize their own current transformers and potential transformers and not share electrical equipment associated with utility revenue metering.

A failure of the DER owner's protective devices, including loss of control power, shall open the automatic disconnect device, thus disconnecting the generation from the utility system. A DER owner's protection equipment shall utilize a non-volatile memory design such that a loss of internal or external control power, including batteries, will not cause a loss of interconnection protection functions or loss of protection set points.

All interface protection and control equipment shall operate as specified independent of the calendar date.

For monitoring and control of new DG projects, the most current version of the Monitoring and Control Criteria should be employed by the utilities to evaluate the need for such equipment in New York and considered in the NPCC region if no other local criteria are available. The New York Monitoring and Control Criteria document was developed and agreed to through a collaborative process as part of the Interconnection Technical Working Group (ITWG). This document can be found on the Department of Public Service website (www.dps.ny.gov) at the Distributed Generation/Interconnections tab under Interconnection Technical Working Group Information. The communications hardware, protocols, and data models must comply with local utility standards.

Also and fundamentally, existing over-current protections in distribution system are typically designed to clear line and ground faults occurring downstream from their location, as the source feeding the fault is only the transformer station. Connecting a DER provides another source supplying the fault, and the fault contribution from the facility might cause protection to operate non-selectively for reverse faults, out of the protected zone. If the maximum reverse fault current through a non-directional fault-interrupting device exceeds the setting of the device, the fault-interrupting device should be considered with a directional feature to prevent tripping for reverse fault current flow. For instance, phase protection could be replaced with an impedance relay (function 21) if required.

Metering

Metering requirements shall be determined by the configuration of the DER system. New metering or modifications to existing metering will be reviewed on a case-by-case basis and shall be consistent with metering requirements required by the local connecting utility and adopted by the local regulatory jurisdiction. Net Energy Metering should be installed when a DER has the capability or potential to

provide resources back into the Distribution System, however, the eligibility of a DER provider to receive net metering will be subject to the rules of the interconnecting utility.

A DER connected to the point of connection should be capable of providing monitoring connection status, real power output, reactive power output, and voltage either at the point of connection or aggregate connection, as required by the distribution utility. The monitoring equipment should be installed at time of interconnection. The distributor and the generator must mutually agree upon communication media options. The DER metering and monitoring communications will allow interoperability and the capability to provide system operators with situational awareness as deemed necessary by the interconnecting utility. As more DER is employed and base load generation is replaced with DER grid-edge resources, it will be important to be able to monitor the availability and production of energy from these resources.

Power Quality

The requirements for acceptable flicker levels shall be in accordance with the latest version of IEEE Std. 1453 Recommended Practice for the Analysis of Fluctuating Installations on Power Systems. Short and long-term perception of flicker shall be within the planning and compatibility levels delineated in this standard. Mitigation measures necessary to comply with these requirements shall at the DER owner's expense.

Power Factor

If the average power factor, as measured at the PCC, is less than 0.9 (leading or lagging), the method of power factor correction necessitated by the installation of the generator will be negotiated with the utility as a commercial item. If the average power factor of the generator is proven to be above the minimum of 0.9 (leading or lagging) by the customer and accepted by the utility, that power factor value shall be used for any further utility design calculations and requirements.

Induction power generators may be provided VAR capacity from the utility system at the DER owner's expense. The installation of VAR correction equipment by the generator- owner on the DER owner's side of the PCC must be reviewed and approved by the utility prior to installation.

Islanding

Systems must be designed and operated so that islanding is not sustained on utility distribution circuits or on substation bus and transmission systems. The requirements listed in this document are designed and intended to prevent islanding and subject to be superseded by local requirements. Special protection schemes and system modifications may be necessary based on the capacity of the proposed system and the configuration and existing loading on the subject circuit.

The need for zero sequence voltage and direct transfer trip protection schemes will be evaluated based on minimum loads on the associated feeder and substation bus, including certain fault conditions resulting from system installation to protect for an islanded condition.

Underfrequency Load Shedding Programs

Under frequency load shedding is implemented to restore power system frequency stability if system frequency drops below the operational set point during major disturbance such as a loss of generation or events in excess of design based contingencies. The importance of an effective automatic UFLS program cannot be overemphasized. UFLS is considered a "safety net" for the BES and a last resort of automatic control operations designed to stabilize BES islands of load and generation for a specific amount of imbalance, typically a 25% deficiency of generation. UFLS is primarily armed on distribution feeders, where DER is increasingly being deployed.

NERC has a set of requirements in their PRC-006 standard and NPCC has more stringent requirements in NPCC's Regional Standard, PRC-006-NPCC which outline expected performance. Approved and effective versions of these standards may both be found on the NERC website.

An NPCC Load Modeling Working Group, SS-38, has studied the UFLS performance of the Region and determined that no change, at this time, is necessary in the UFLS program. The SS-38 has also performed some sensitivity analysis and determined that increased levels of DER penetration in the short term will not result in any significant degradation in UFLS performance.

As DER penetrates in the longer term it may be necessary to adopt a more flexible approach to UFLS. There are utilities that are reviewing the feasibility of "Adaptive UFLS" which uses real time monitoring of distribution feeder loads and their DER to determine how much additional load may need to be tripped when DER has increased output. This increased automation is not necessary within NPCC at this time however our technical groups will continue to assess and affirm the NPCC UFLS program is effective in maintaining reliability.

Effective Grounding for DER

With the onset of high DER such as photovoltaic (PV) penetration, utilities should consider interconnection of PV plants similarly to how they would interconnect synchronous generators. Conventional generators are considered to be voltage sources as they provide constant AC voltages controlled by excitation systems. In contrast, an inverter-based PV plant is modeled as a current source and the DER terminal voltage is dependent on the feeder to which it is connected.

Solidly grounding a transformer neutral for a DER eliminates a possible phase overvoltage stemming from a single-line-to-ground fault. A potential problem with the solid grounding in the distribution line is that large fault currents can flow through the transformer neutral, which can desensitize the overcurrent protection coordination. In order to mitigate this issue, impedance grounding can limit the fault current and potential equipment damage, while allowing overvoltage to some limited magnitude. Some utilities protect their distribution from overvoltage by using overvoltage protection so Effective Grounding isn't a concern. Further investigation on the how specific installations are grounded is warranted and being pursued by the Interconnection Technical Working Group (ITWG) in New York.

Energy Storage Systems for DER

Li-ion batteries have been and continue to be deployed in a wide range of energy-storage applications, ranging from energy-type batteries of a few kilowatt-hours in residential systems with rooftop photovoltaic arrays to multi-megawatt containerized batteries for the provision of grid ancillary services. The Energy Storage Association (ESA) anticipates at least 35 GW of new energy storage in the United States by 2025 and that the amount of energy storage will double from 2018 levels during 2019.

The ESA in conjunction with over 25 vendors and utilities have formed a task force and made a commitment to optimize safety standards. Care should be used in placement of batteries. Suggested placements should avoid proximity to other facilities that may be critical the reliability of the BES.

DER BES Recommendations

As DER continues to penetrate the NPCC Region we suggest the following initial activities:

Process and Risk Management Recommendations

1) Continue with sensitivity analysis at the Transmission level for various levels of penetration of DER on distribution facilities to determine any adverse effects on UFLS performance.
2) Pursue further opportunities to coordinate distribution and transmission reporting requirements for generating resources and promote NPCC Regional consistency where possible.
3) Continue to review NPCC Area authorities having jurisdiction and utility interconnection requirements documents to identify dissimilarities which may negatively impact reliability.
4) Identify opportunities to share information regarding problems and problem solving.
5) Continue to solicit and address observable reliability issues of DER initiated BES impact through the use of NPCC's DER Impact Reporting Forms and its associated process.
6) Continue to discuss any changes required for System Restoration and Blackstart Plans, as a result of increased DER.
7) Continue to follow ESA ESS safety issues and associated recommendations and share the results with NPCC stakeholders.

Planning Related Recommendations Due to Changing Resource Mix

8) Obtain DER modeling and performance data to enable Operational Planning of the BES
9) Clearly identify DER in the NPCC Region's Area queues, where DER is being proposed for installation and the magnitudes relative to the existing resource base and load projections.
10) Obtain modeling data to enable modelling of the BES for the purposes of Long-Term Resource Planning with DER
11) Obtain modeling data to enable modelling of the BES for the purposes of Long-Term Transmission Planning
12) Address masking of load by DER at the distribution level to ascertain its impact on the assumptions that underpin UFLS programs

Analytics and simulation recommendations to deal with increase system complexity

13) Support interconnection wide inertia loss study efforts, to determine potential reliability impacts, as DER increasingly replaces conventional synchronous generation resources.
14) Obtain modelling data to be able to predict and examine system behavior and assess the interactions between the new resources and the existing reliability preserving systems and programs. Examples include:
    a. Under Frequency Load Shedding,
    b. Under Voltage Load Shedding,
    c. Frequency response sharing mechanisms (BAL standards).
    d. Analysis of system protection systems (both T and D) so that the parameters to set protection systems and other control systems are known so as to permit the most reliability benefits to be garnered from the new resources.

Appendix A NPCC DER Impact Reporting Form



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

Please Complete and email this form to; npccstandard@npcc.org

Distributed Energy Resource (DER), BES Impact Reporting Form

Name		**Date**	

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

Equipment Impacted

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

Description of Impact on BES- What Happened or was observed?

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

Root Cause or additional Analysis

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

NPCC Review of Issue and Recommendations (i.e. Refer to NERC, develop a Criteria, Guideline, Already Addressed or Identified, etc.)

NPCC Date of Resolution of Issue _____

Appendix B, NPCC Areas-Comparisons

Key Inverter based specification extracts

	ISO-NE Inverter Requirements	NG ESB 756 B, C, D	NY SIR	IESO F2 Technical Requirements
Inverter Certification	yes	yes	yes	yes
Voltage and frequency trip settings for inverter based applications	yes	yes	yes	yes
Voltage Response	yes	yes	yes	yes
Frequency Response	yes		yes	yes

Abnormal performance capability (ride-through) requirements for inverter based applications	yes	yes		
Other grid support utility interactive inverter functions statuses	yes			
Minimum protection functions		yes	yes	
Monitoring and Control		yes	yes	yes
Reconnection to the System		yes	yes	
Distribution Protection Coordination		yes		yes
Inverter Certification		yes	yes	
Power Quality			yes	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

SPIDER Working Group

Dan Kopin
Utility Services, Inc.
NPCC Regional Standards Committee
August 2019

RELIABILITY | ACCOUNTABILITY







Google

SPIDER Working Group

A. *Massachusetts*
B. *Texas*
C. *Louisiana*
D. *Ohio*
E. *California*



SPIDER Working Group

The SPIDER Working Group is a NERC stakeholder forum focusing on Distributed Energy Resources (DER) from transmission-level perspectives

DER is defined as…

"Any resource on the distribution system that **produces** electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System."

Presentation Overview

- ERO Enterprise Operating Plan – Goal 4 (2017)
- SPIDER Work Plan 2019 – Q2
  - Reliability Guidelines
  - Other Tasks
- Reliability Guideline
  - Recommended Approaches for Developing Underfrequency Load Shedding Programs with Increasing DER Penetration

Goal 4: Identification and Assessment of Emerging Reliability Risks

Key ERO Enterprise Contributing Activities

- Identify risk-based data needs, collection, analysis, and modeling technology to assess the impact of emerging risks, including distributed energy resources, on planning, operations, and restoration and recovery, incorporating the identification of data and information-sharing needs. (e.g., collecting phasor measurement unit data, benchmarking dynamic load models to improve software, and performing analysis of distributed energy resources/dynamic load contribution modeling).

Goal 4: Identification and Assessment of Emerging Reliability Risks

Key ERO Enterprise Contributing Activities

- Augment data collection and insights into distributed energy resources and their potential impact on the BPS. Identify the type and periodicity of information needed from distributed energy resources to improve load forecasting, generator modeling, and situation awareness. Address coordination requirements between BPS and distribution system planners and operators to account for the uncertainty introduced by integration of variable generation, including the impact of weather on these resources.

NERC Planning Committee Work Plan 2019 – Q2

Subgroup	Reliability Guidelines	Target Date
Modeling	• DER Data Collection for Modeling • DER_A Model Parameterization	• Q4 2019 • Q3 2019
Verification	• DER Performance and Model Verification • DER Forecasting Practices and Relationship to DER Modeling for Reliability Studies	• Q4 2019 • Q4 2020
Studies	• Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources • Recommended Approaches for Developing Underfrequency Load Shedding Programs with Increasing DER Penetration • Recommended Approaches for Developing Undervoltage Load Shedding Programs with Increasing DER Penetration	• Q2 2020 • Q4 2019 • Q4 2019
Coordination	• Communication and Coordination Strategies for Transmission Entities and Distribution Entities regarding Distributed Energy Resources	• Q4 2019

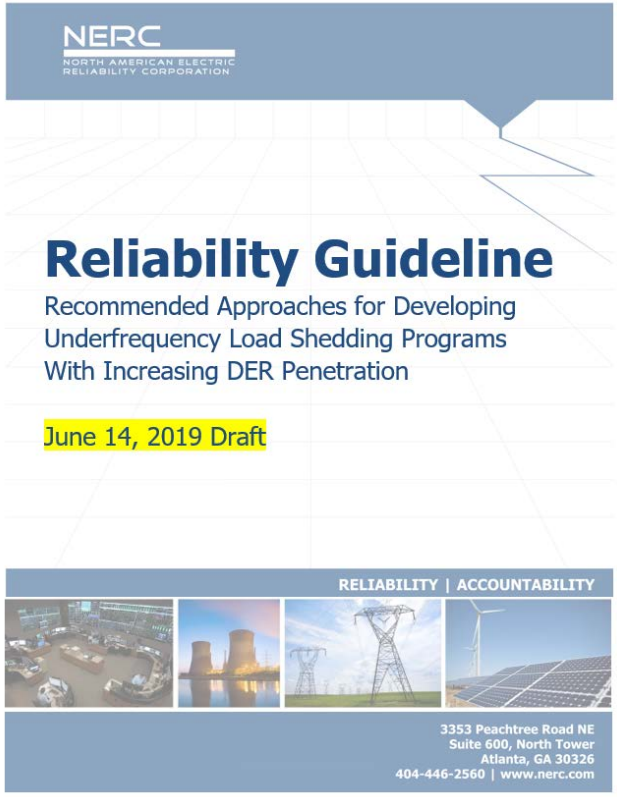
NERC Planning Committee Work Plan 2019 – Q2

Subgroup	Other Tasks…	Target Date
Modeling	• Review of **MOD-032-1** for DER Data Collection for Interconnection-wide Modeling – **SAR for Next PC Meeting** • Modeling Survey: DER Modeling Practices of SPIDER Members • Modeling Notification: Dispatching DER off Pmax in Case Creation	• Q2 2019 • Q3 2019 • Q3 2019
Verification		
Studies	• Review of **TPL-001-5** for Incorporation of DER • White Paper: Recommended Simulation Improvements and Techniques • White Paper: Beyond Positive Sequence RMS Simulations for High DER	• Q4 2019 • Q2 2020 • Q1 2020
Coordination	• White Paper: Review of IEEE Std. 1547-2018 for Impacts to BPS • Educational Material to Support Information Sharing between Industry Stakeholders • Coordination of DER Terminology • NERC Reliability Standards Review • Tracking and Reporting DER Growth	• Q3 2019 • Q3 2020 • Ongoing • Q3 2019 • Ongoing

Reliability Guideline: Recommended Approaches for Developing UFLS Programs with Increasing DER Penetration

Guidance on how to study UFLS programs and ensure their effectiveness with increasing penetration of DER represented.

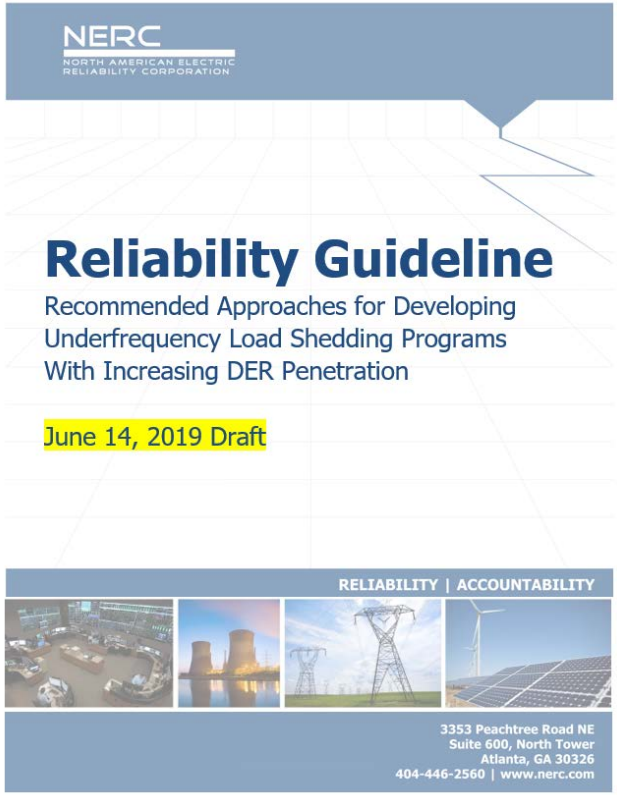
Premise: *If a higher percentage of load is served by DER, island-level frequency will be impacted. UFLS program design should follow from those impacts.*



Reliability Guideline: Recommended Approaches for Developing UFLS Programs with Increasing DER Penetration

Guidance on how to study UFLS programs and ensure their effectiveness with increasing penetration of DER represented.

- Background
- Impacts of DER on Island-Level Frequency
- Impacts of DER on UFLS Program Design
- Recommendations



SPIDER Working Group

Participating Organizations: March 2019 – June 2019
AESO
ComEd
ConEd
Entergy
ERCOT
FERC
Hydro One
Hydro Quebec
HydroOne
ISO New England
MISO
National Grid
NERC
NYISO
Oncor
PacifiCorp
PG&E
Sargent & Lundy
SPP
Utility Services

Background: UFLS Programs

"UFLS programs are inherently heterogeneous as programs are developed to balance electrical islands with different characteristics of generation and load."

"PRC-006-3 and its variances afford PCs flexibility to develop UFLS programs suited to their respective electrical islands."

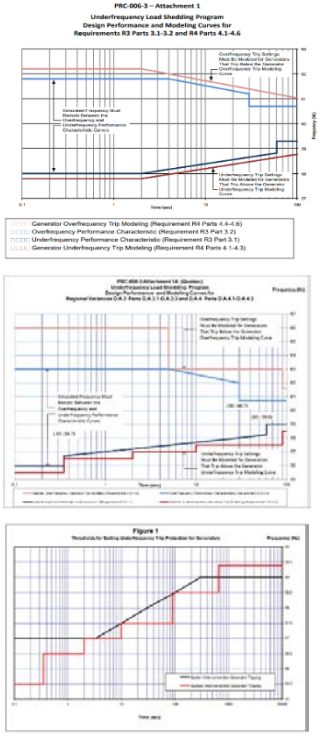


Table 1: Load Shedding Requirements in ERCOT, ISO New England, and PJM

Frequency Set Point (Hz)	ERCOT[1]	ISO New England[2]			PJM[3]			
	All DSPs	Peak ≥ 100	50 ≤ Peak < 100	25 ≤ Peak < 50	MACZ	WCZ	CECZ	SCZ
59.5		6.5-7.5%	14-25%	28-50%		5%		
59.3	5%	6.5-7.5%			10%	5%	10%	10%
59.1		6.5-7.5%	14-25%			5%		
59.0							10%	10%
58.9	10%	6.5-7.5%			10%	5%		
58.7						5%	10%	
58.5	10%				10%			10%
59.5 (10s)		2-3%						
Total % Shed	25%	29.5-31.5%	28-50%	28-50%	30%	25%	30%	30%

1. See ERCOT Nodal Operating Guides Section 2.6.1(1) for further information.
2. See PRC-006-NPCC-1 for further information. Please note that Peak values are in MW.
3. See PJM Manual 36: System Restoration Section 2.3.2 further information.

Background: FERC Order No. 763 (2012)

Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards

- PRC-006 "*does not limit the resources that can be modeled in the UFLS assessments*" and "*does not require all of the generation that is not directly connected to the bulk electric system to be included in the modeling*"

- "*Not requiring applicable entities to model **sufficient amounts** of qualifying generation **indirectly connected** to the bulk electric system [that **may serve load designed to be shed in a UFLS program**] could result in applicable entities not knowing how those resources react during underfrequency situations, which could cause excessive load shedding in an emergency and further contribute to system instability*."
  - Sufficient amounts? **20 MVA (DER)** and **75 MVA (DER Aggregation)**.

Background: NERC's "High Levels of DER" Standard is Consistent with Order No. 763

2011 Special Report: Potential Bulk System Reliability Impacts of Distributed Resources

*At **high levels of DER**, the effectiveness of existing underfrequency and under voltage load shed schemes may need to be reviewed…*

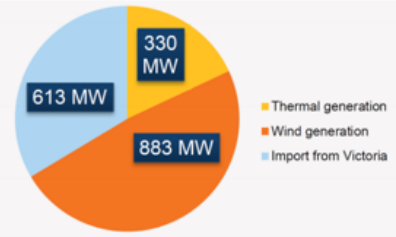
2017 Distributed Energy Resources Connection Modeling and Reliability Considerations

*DER are not coordinated with UFLS programs nor are they used to calculate the most severe single contingency and contingency reserve requirements. **High levels of DER** with inverters can also result in a decline in short circuit current, which can make it more difficult for protection devices to detect and clear system faults. Hence, the implications of DER as part of system protection must be taken into consideration while planning the BPS and distribution systems…*

Impact of DER on Island-Level Frequency: Rate of Change of Frequency

2017 Black System – South Australia – 28 September 2016 (AEMO)

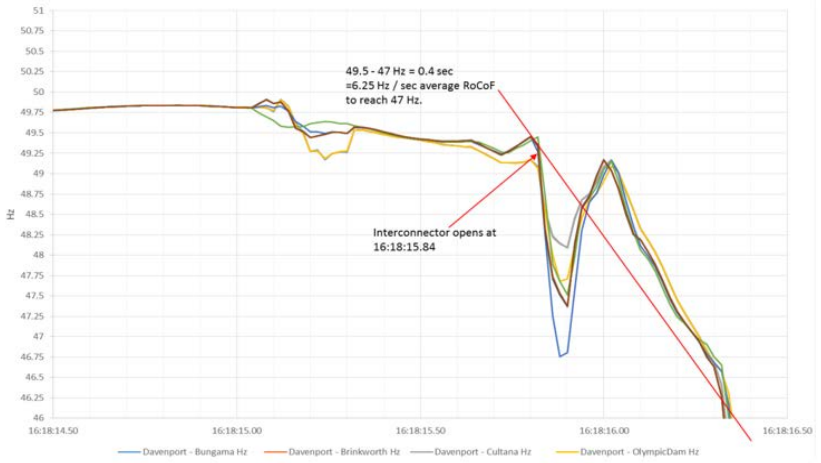
BPS-Connected Inverter-Based Resources Example: Displacement → Higher RoCoF



South Australia Generation Mix Pre-Event (AEMO, 2017)



Total Wind Farm Output – Sustained vs. Transient Power Reduction, September 28, 2016 (AEMO, 2017)



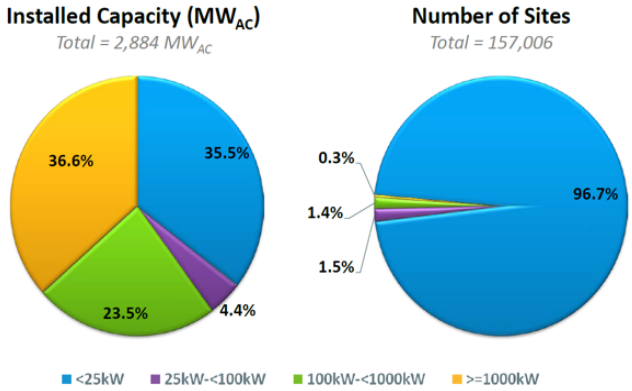
Frequency and ROCOF in Various SA Nodes Immediately Before the System Separation (AEMO, 2017)

The RoCoF following separation of the South Australian system was 6.25 Hz per second, "**too great for the UFLS scheme to operate effectively**".

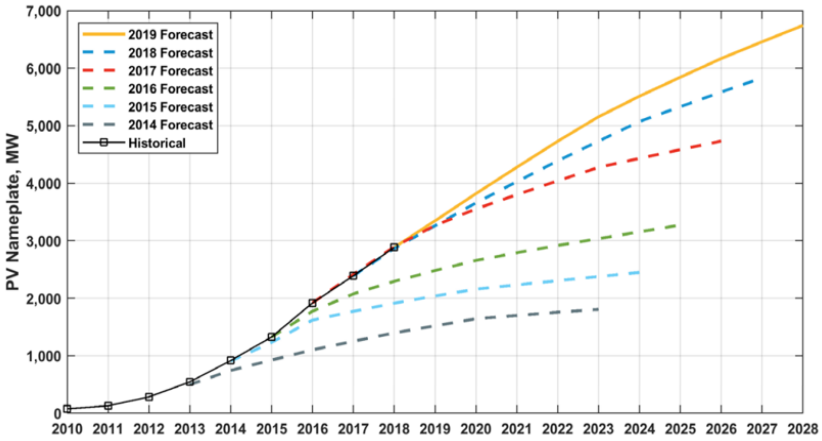
…NERC ERSTF (2015) also highlighted the importance of Synchronous Inertial Response and Rate of Change of Frequency (RoCoF).

Impact of DER on Island-Level Frequency: Available Load Shed

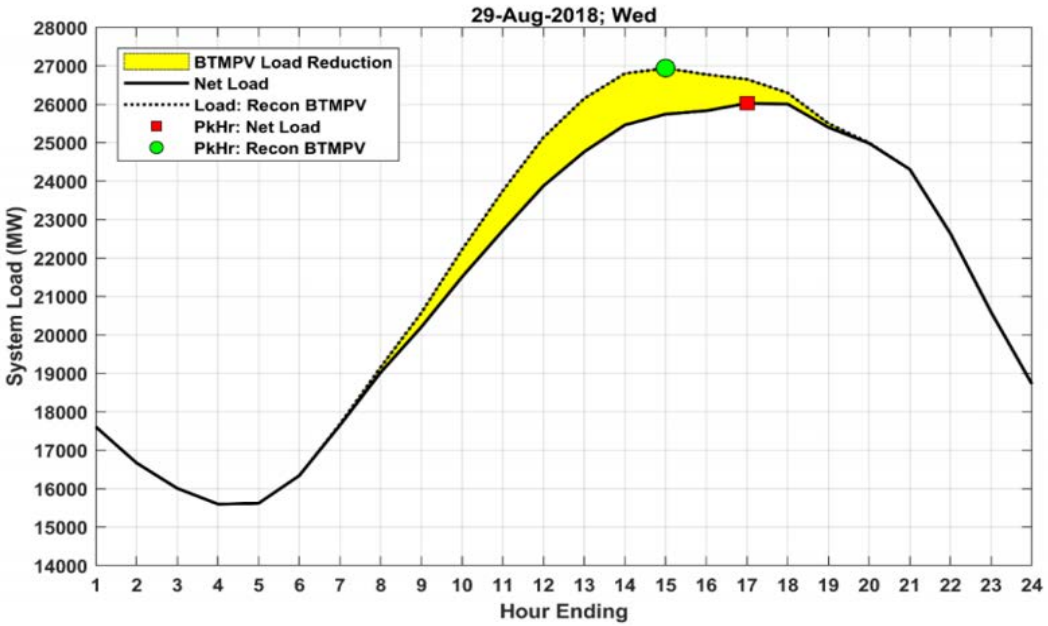
ISO New England's Islanding Study – Impact of DER



Installed PV Capacity as of December 2018 – ISO New England by Size Class



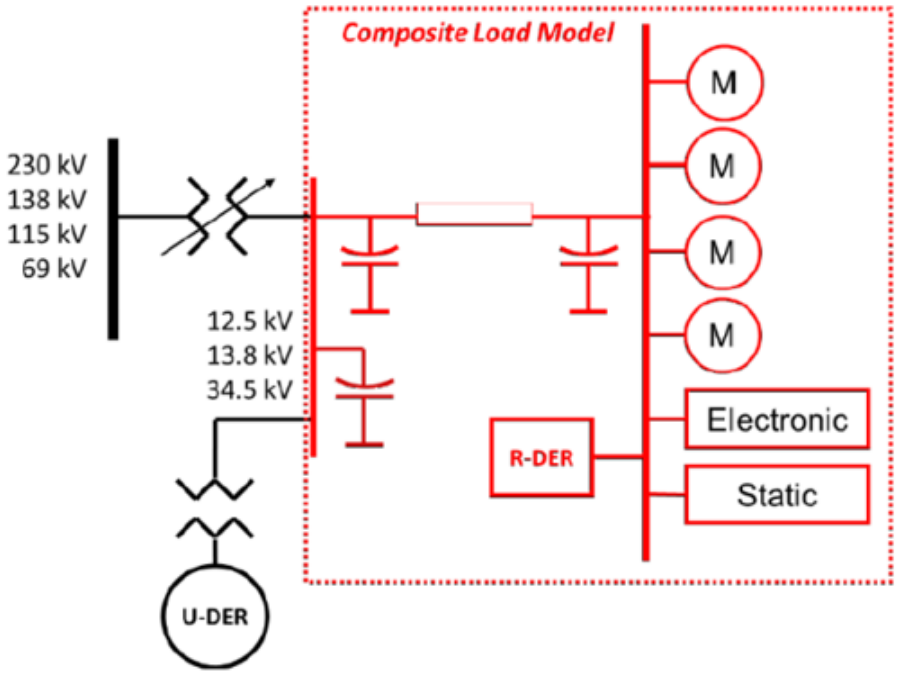
PV Growth: Reported Historical vs. Forecast



Example of BTM PV Impact on Summer Peak Day – August 29, 2018

Impact of DER on Electrical Island-Level Frequency: Available Load Shed

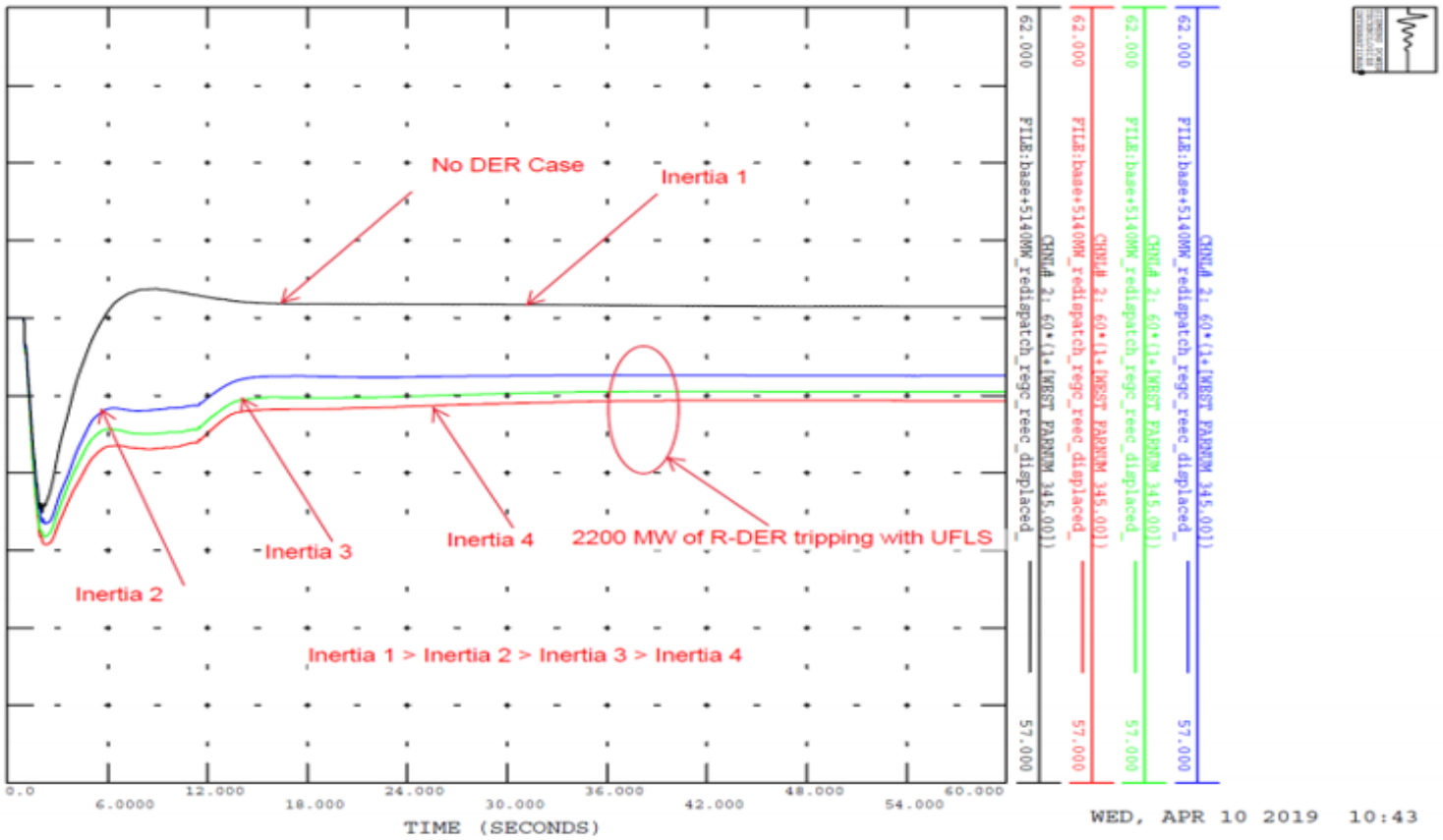
ISO New England's Islanding Study – Impact of DER



Dynamic Load Model with R-DER and U-DER Represented

Impact of DER on Electrical Island-Level Frequency: Available Load Shed

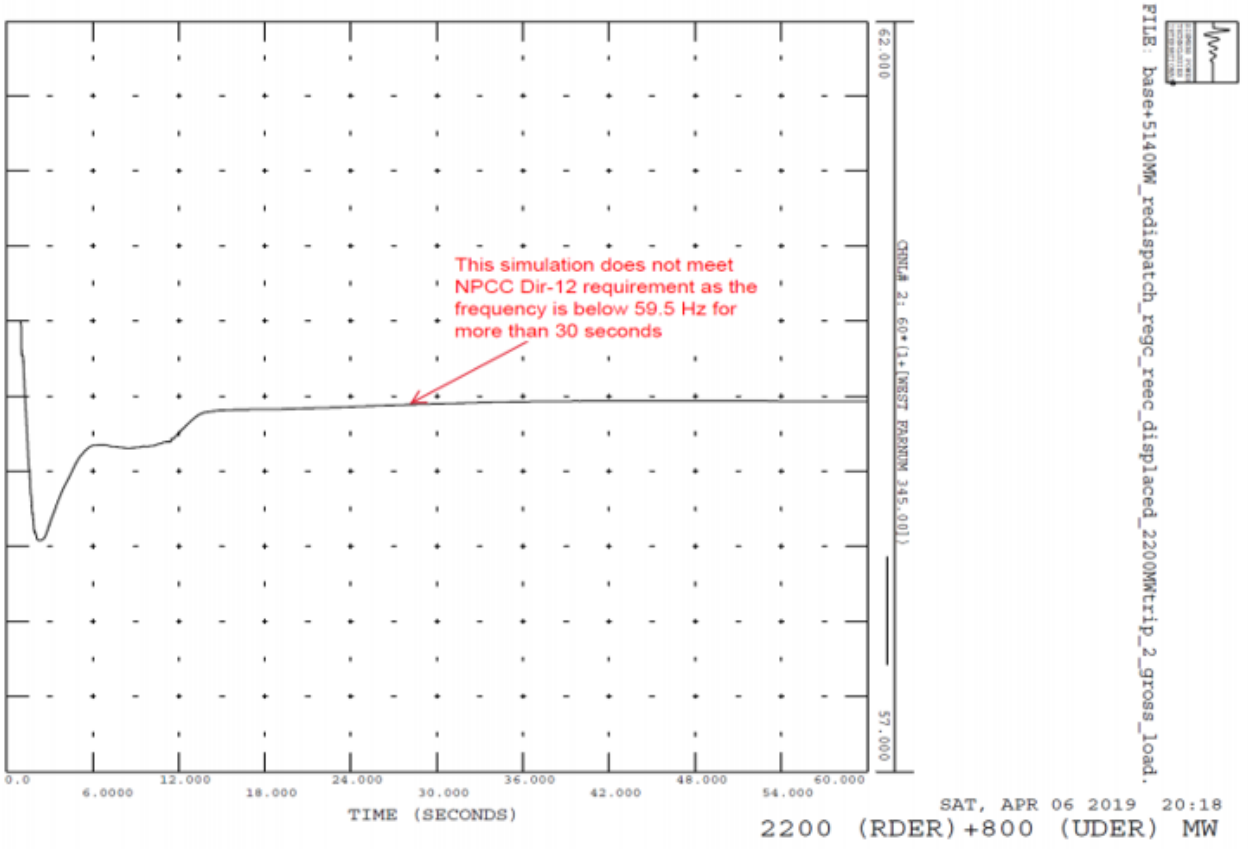
ISO New England's Islanding Study – Impact of DER



ISO New England Island Frequency Performance – 60 Seconds

Impact of DER on Electrical Island-Level Frequency: Available Load Shed

ISO New England's Islanding Study – Impact of DER



ISO New England Island Frequency Performance Relative to NPCC Directory #12

Impact of DER of UFLS Program Design:

Frequency Set Points

*Ensuring that RoCoF is not too high for the UFLS scheme to operate effectively **may require mechanisms to ensure sufficient frequency response…***

Load Selection

*Although UFLS entities typically implement UFLS programs by selecting specific feeders for UFLS, there is **no requirement under PRC-006-3 that requires tripping entire feeders…***

Adaptive UFLS Design

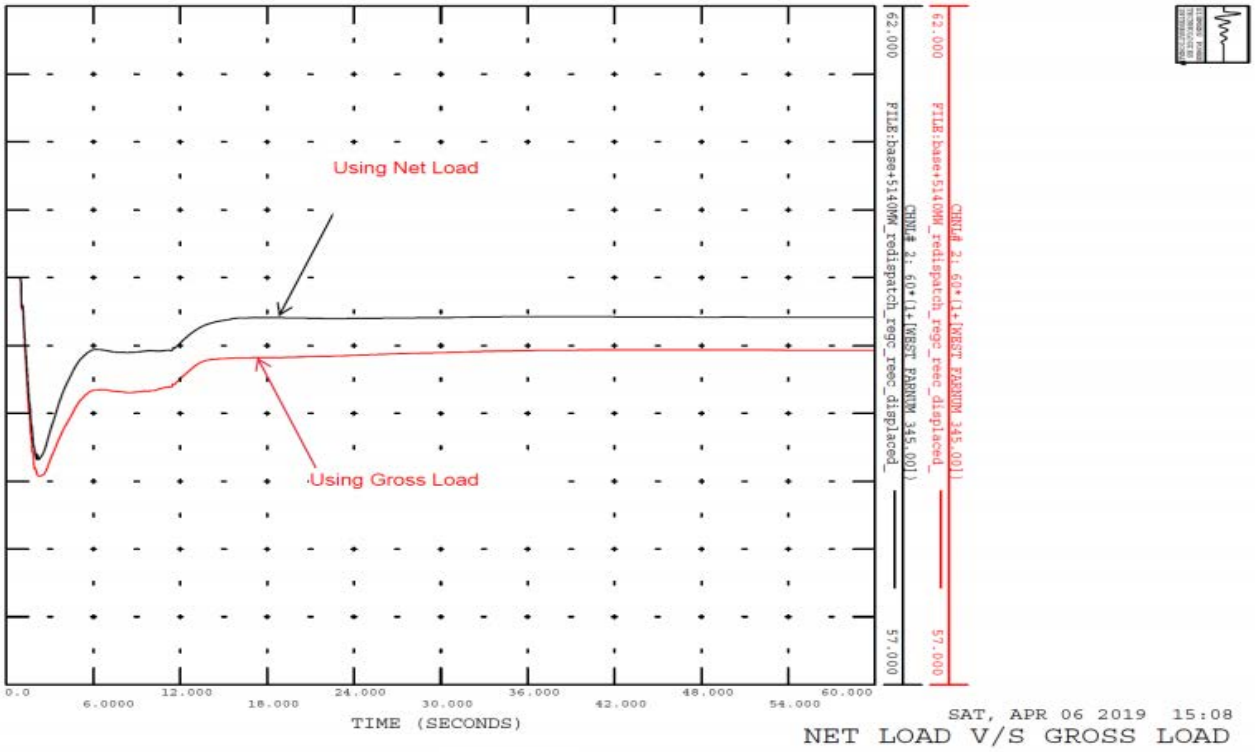
- Stage 1 and stage 2 should sum to 15% of the system net load
  - maximum allowed load shedding for N-1 unit trips.
- Stage 1 through stage 4 should sum to 40% of the system net load which is the maximum allowed load shedding for N-1-1 unit contingencies
- Adjust the stages of UFLS to reflect a percentage of net system load on each stage.
  - Df/dt – 15%, 0.5 Hz/sec, 9 cycle relay plus breaker time (not currently active)
  - Stage 1 – 5%, 59.1 Hz, 8 cycle relay plus breaker time
  - Stage 2 – 10%, 58.8 Hz, 8 cycle relay plus breaker time
  - Stage 3 – 10%, 58.5 Hz, 8 cycle relay plus breaker time
  - Stage 4 – 15%, 58.2 Hz, 8 cycle relay plus breaker time
  - Stage 5 – 10%, 57.9 Hz, 8 cycle relay plus breaker time
  - Stage 6 – 20%, 57.6 Hz, 8 cycle relay plus breaker time
- Retain most recent UFLS settings in the event of SCADA/EMS communication failure until communications are restored.

Case Study: Hawaii Electric Light

Recommendation: Model Island-level Gross Load > Island-level Net Load

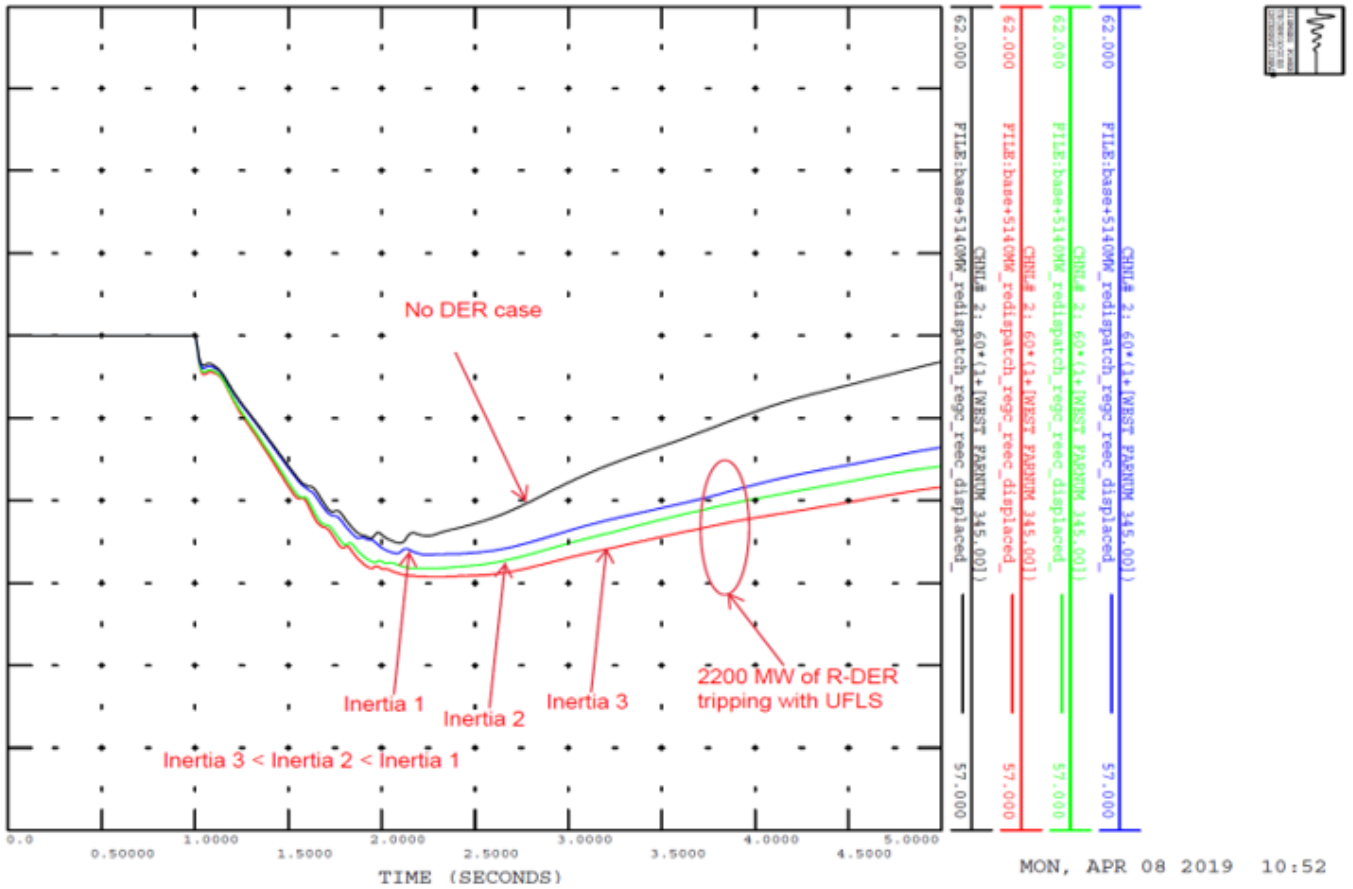
imbalance = [("net" load — actual generation output) / ("net" load)], of up to 25 percent within the identified island(s)

imbalance = [("gross" load — actual generation output) / ("gross" load)], of up to 25 percent within the identified island(s)



Recommendation: Model "Sufficient Amounts" of DER within UFLS Entity Footprints

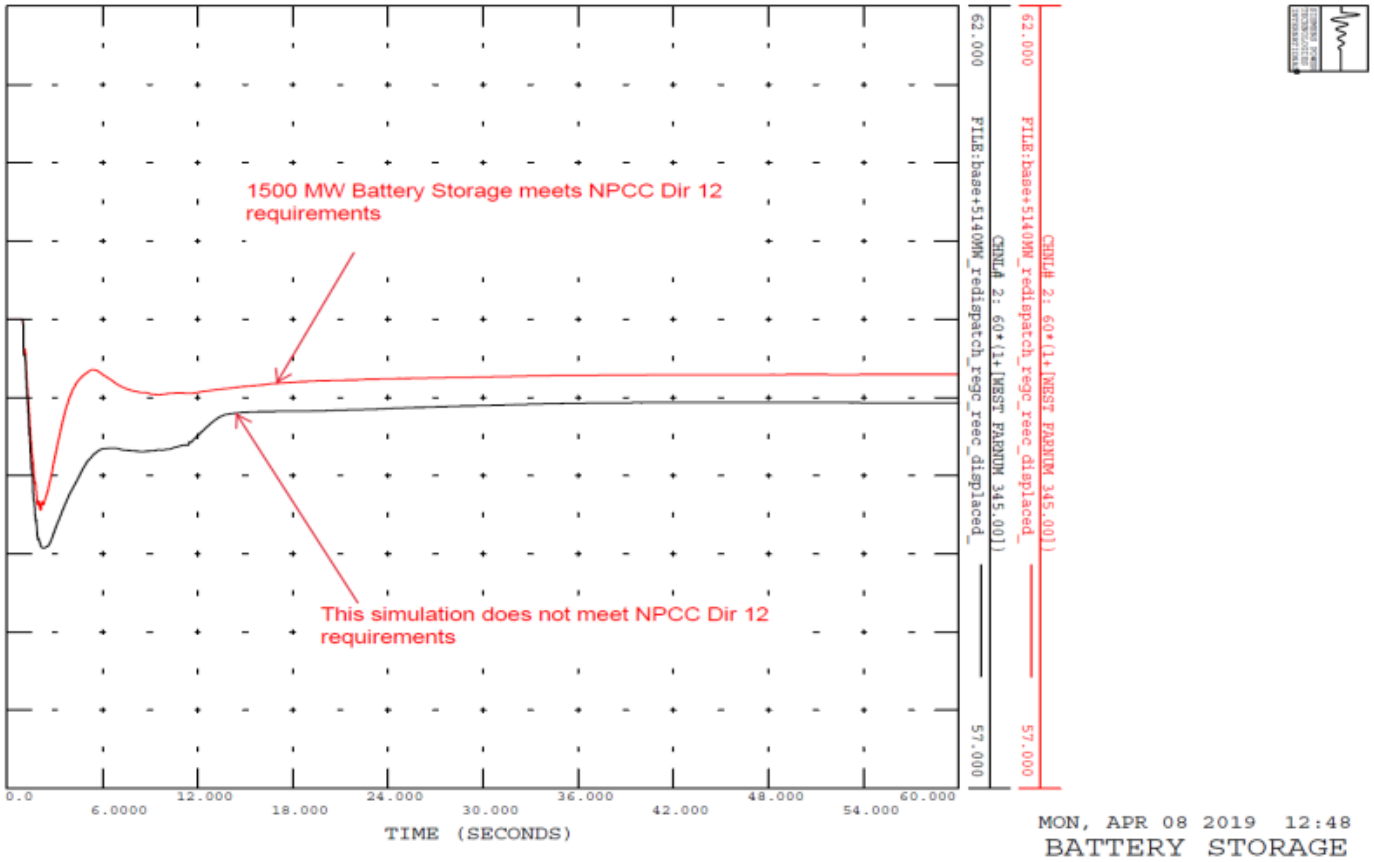
- 2,200 MW of Residential-scale DER displacing synchronous generation has a material impact on island-level frequency…



ISO New England Island Frequency Performance – 5 Seconds

Recommendation: New Technologies May Improve Island Performance…

- E.g. 1,500 MW of battery storage (6 MW at 250 buses) would improve island performance…





Questions and Answers

2019 OPERABILITY ASSESSMENT

Mohab Elnashar, PhD, P.Eng.

Senior Engineer – Performance Validation & Modeling

July 23, 2019

ieso
Connecting Today.
Powering Tomorrow.

What is an Operability Assessment?

An Operability Assessment is a study of the IESO's ability to **effectively** and **reliably** operate the power system **into the future** based on our real-time operating experiences.

Assessment Objective: Recommend changes to power system design or market mechanisms, processes and/or tools to address operability **concerns**

Why did we do this assessment?

- We wanted to answer the question:

  What is the impact upon bulk power system operations of increased penetrations of inverter-based Distributed Energy Resources (DERs), especially during light loading conditions?

DERs, or Distributed Energy Resources, are generators connected to distribution systems

Why did we do this assessment?

- We have already seen instances of reduced power system responses after a fault
  - Observed as part of our regular monitoring required by NERC balancing standards
- New knowledge from other system operators:
  - 2016 California Bluecut forest fire caused a transmission fault; triggered an unexpected 1200 MW solar generation loss
  - 2017 California Canyon forest fire caused two transmission faults; triggered an unexpected 900 MW solar generation loss

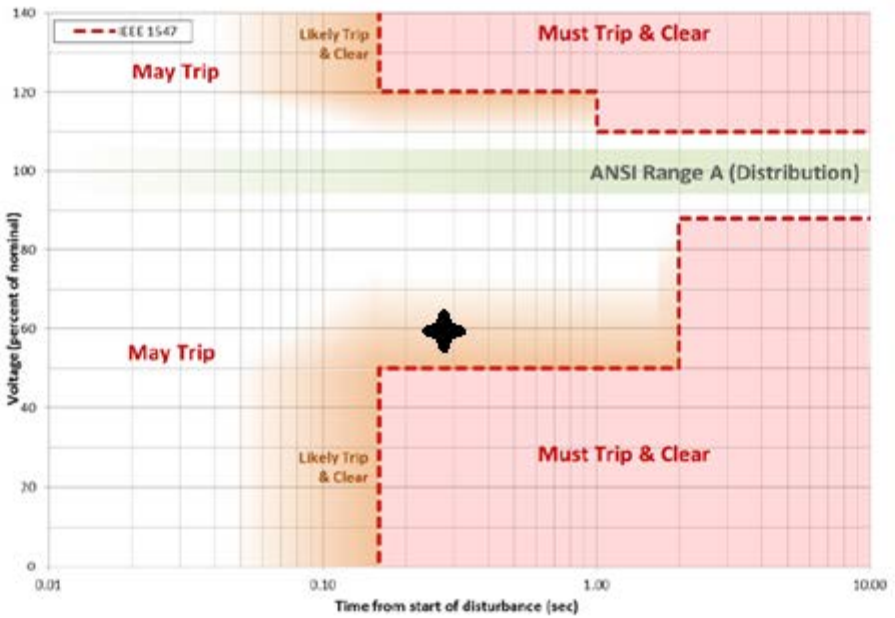
What major changes are expected in future?

- Increased penetrations of DERs
  - Reduce power system transfers and grid demand
  - Inverter-based DERs behave differently than traditional synchronous generators
- Long-term outages and retirement of nuclear generators
  - Reduce power system responses after a transmission fault

Distributed Energy Resources - Limitation

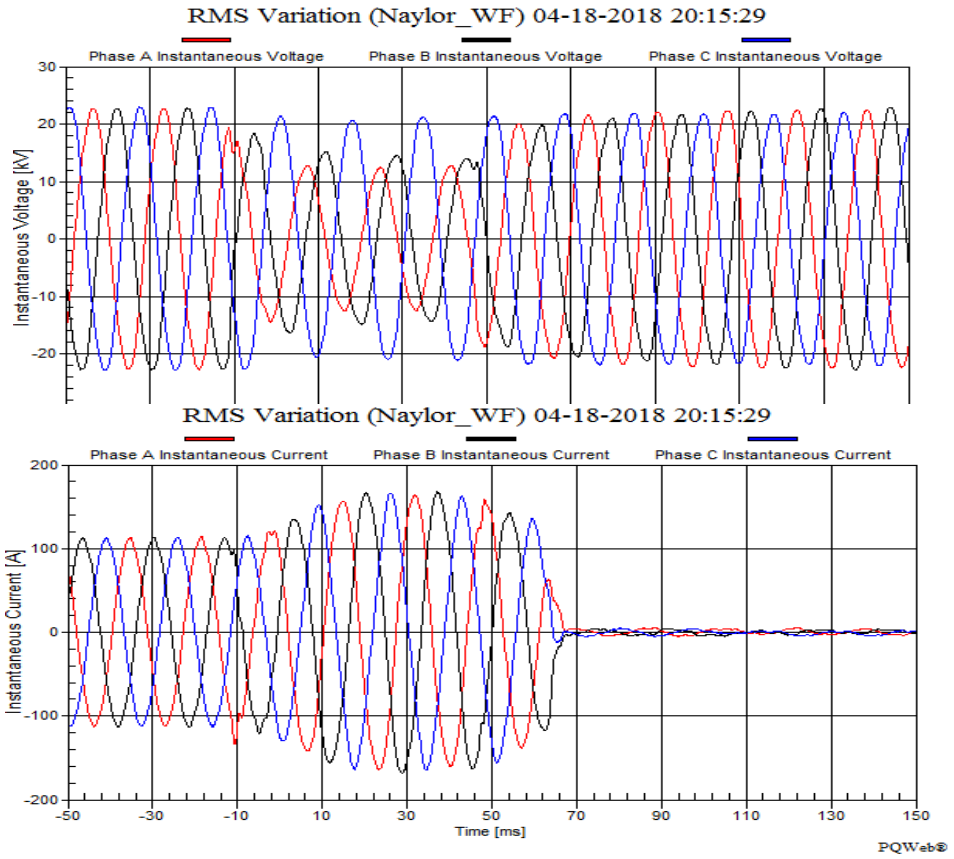
- Voltage Ride-Through Capabilities – Performance during and after a fault

Figure 1: IEEE Standard 1547 Voltage Sensitivity



Distributed Energy Resources - Limitation

- DER trip due to a fault



What did we study?

- Developed study conditions/scenarios that incorporated the following items:

	2025
DERs – IESO driven FIT and LRP projects	All inverter-based projects ≥ 100 KW in-service at high outputs
Pickering NGS	Retired
Bruce and Darlington NGSs	Up to 4 units will be out of service for long-term outages
Low grid demands	As low as 8500 MW

- Studied how the power system responds during and just after a transmission fault

What power system responses were assessed?

- **Single Largest Contingency** - A large number of DERs may trip following a transmission fault, resulting a new single largest contingency that needs to be respected

- **System Inertia** - High penetration of DERs will lower the system inertia of the IESO-controlled grid

- **Primary Frequency Response** - High penetration of DERs will lower frequency response provided by Ontario

What did we find?

- Under certain system conditions, ¾ of DER production in Ontario will trip due to the effects of a transmission fault
  - The sudden loss of a single Darlington unit is typically Ontario's 'Single Largest Contingency' (SLC) today
  - If the fault occurs at Darlington, a Darlington generator and DERs will trip, causing a new and very large SLC for Ontario

What did we find?

- We will have sufficient traditional synchronous generators (i.e., hydro-electric and/or nuclear) to support System Inertia and Primary Frequency Response after a transmission fault

What do we need to do?

1. Change voltage trip settings on inverter-based DERs:
   - Work with the Ontario Energy Board (OEB) to modify the Distribution System Code (DSC) by adopting the new Canadian Standards Association rules on DER performance
   - Engage local distribution companies and DER owners

DER size (MW)	Percentage of total installed capacity (%)	Number of DER facilities
≥ 10	50%	134
≥ 5.0	66%	192
≥ 1.0	67%	204
≥ 0.5	76%	721
≥ 0.1	100%	3721

What do we need to do?

2. Consider increasing occasionally Operating Reserve as an interim measure
   - Needed when loss of DERs is SLC for a transmission fault
3. Identify any cost-effective transmission reinforcements that could reduce the generation lost from DERs due to a single contingency.
4. Continue regular monitoring of how the system responds to transmission faults
   - Quarterly for primary frequency response
   - Annually for system inertia

2019 Operability Assessment – Next Steps

- Collaborate with OEB, LDCs and DER asset owners to change voltage trip settings
  - *What does this mean to DER asset owners?*
    - Likely to be an OEB implementation plan with direction from IESO and coordination from LDC
    - No reduction of output capability
    - No change in equipment
    - Less interruptions due to transmission and distribution faults
- Update the DSC based on CSA standard
- 2019 Operability Assessment report

Questions





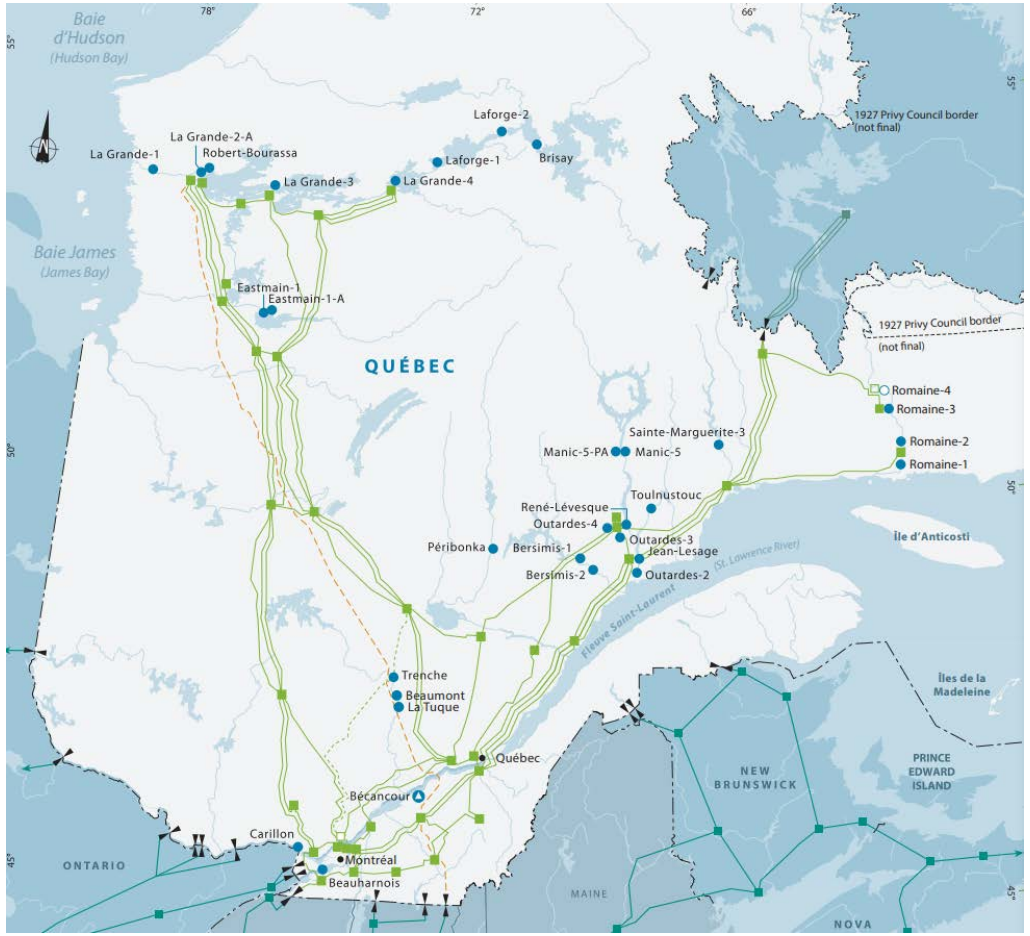
SYSTEM EVOLUTION WITH DER

Hydro-Québec TransÉnergie Progress Status

Nicolas Compas, P. Eng.

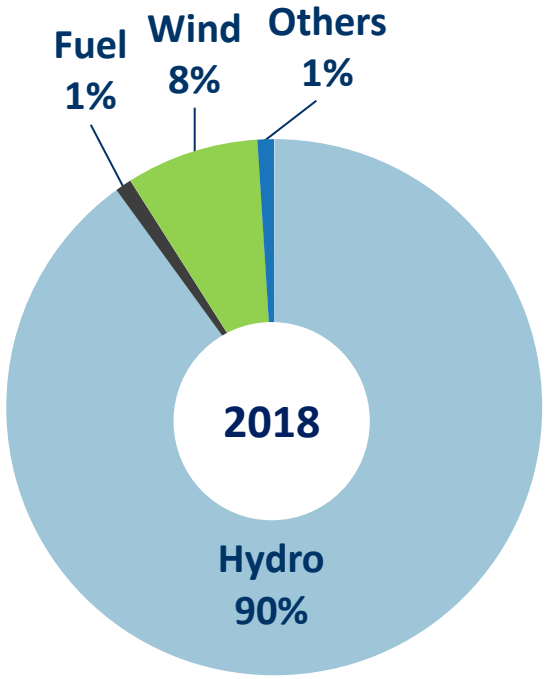
Hydro-Québec TransÉnergie | August 8th 2019

Hydro-Québec current situation



Overview

- 99% of our generation is already renewable : no decarbonization goal
- Production in the north, load in the south, very long lines in-between : rotor angle, voltage and frequency stability issues
- Peak demand is during winter (residential heating)
- Clean energy & low price:
  - Slower PV penetration
  - Faster EV penetration

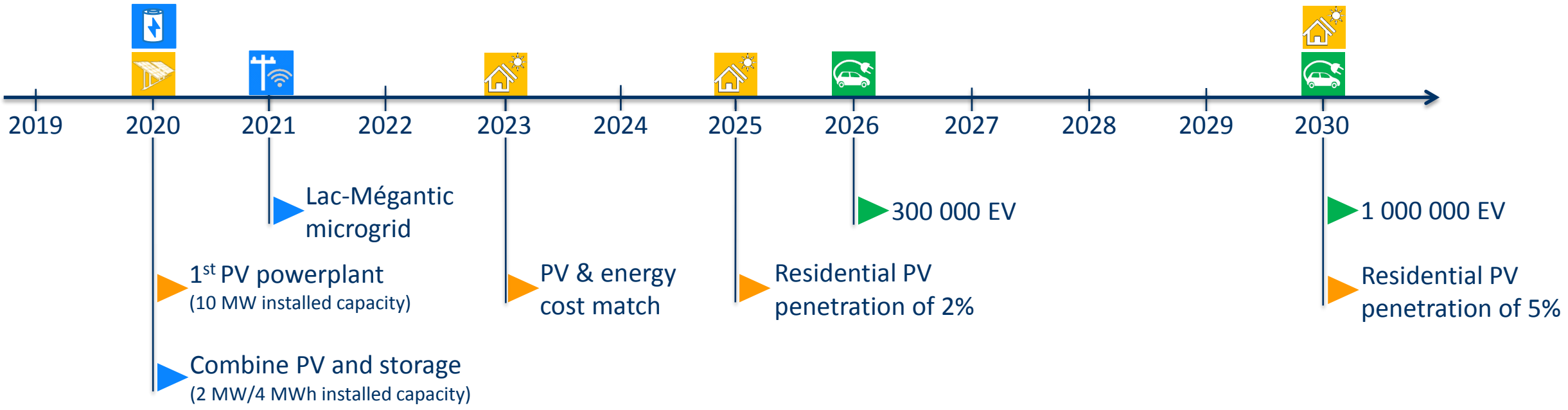


Timeline of DER events

HQ's DER vision:

DER is not only distributed solar energy
it is also:

EV – smart load – storage – wind – small hydro



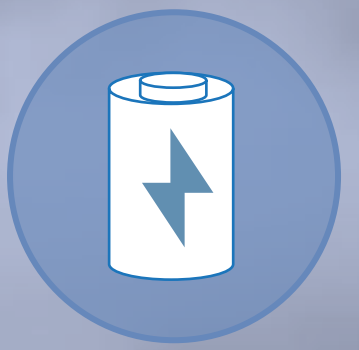
DER perspective on the network in 10 years



2030: 1 000 000 EV



2030: PV 5% penetration



Hydro-Quebec already has a large storage capacity: dams

- Peak demand and power ramping will rise
- Warm up in the morning and plug in the evening

- No contribution during peak demand (winter am & pm)
- Power ramping will rise
- Low inertia during summer

- Distributed storage might be a solution to more local needs

Two main strategies under development



Reactive: Business as usual

- Increase our knowledge of DER and their impacts on the system
- Update our technical requirements (grid code)
- Create a tool to have a bottom-up view of our system



Proactive: DER as part of the solution

- Researching values in non-wires solution
- Improve the bottom-up tool to optimize T&D solutions

Increase our knowledge (some examples)

Smart home testing field



- 2 identical houses with different technologies
- Field test for control (V2G, storage, heating) in QC conditions
- Residential storage is not meant to help utilities (ex: charging immediately after an outage)

PV converters test



- 8 residential converters tested
- Voltage and frequency performances analysed
- Default settings not meeting HQ technical requirements
- Settings are very difficult to change, when possible

Substation storage



- 2,4 MWh storage unit at Hemmingford substation
- Testing peak response strategies for local issues
- Will test voltage and frequency response in the near futur

Update our technical requirements (Grid Code)

Specific requirements for Inverter Based Resources

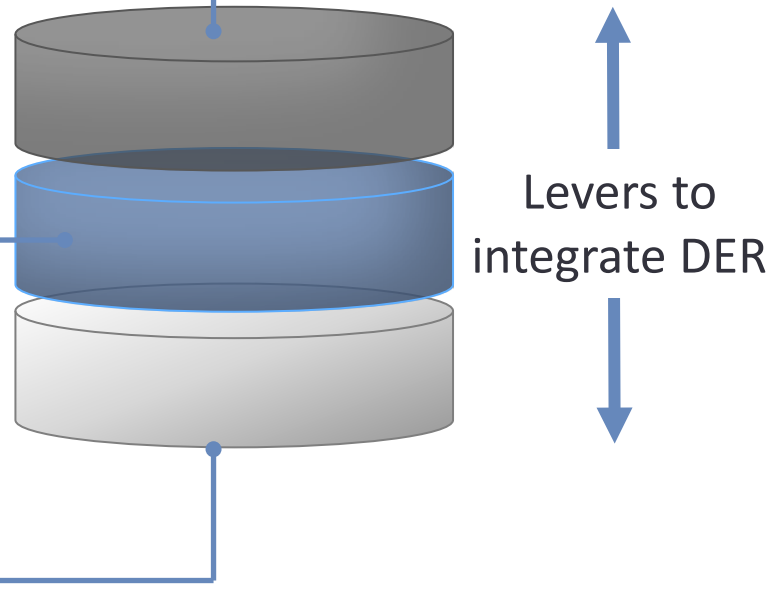
- Frequency response (low inertia issues)
- Participation in NERC groups IRPTF & SPIDERWG
- P-Q curve, ….

T&D technical requirements harmonization

- Islanding strategies
- Inverter performances
- Protection and shedding issues

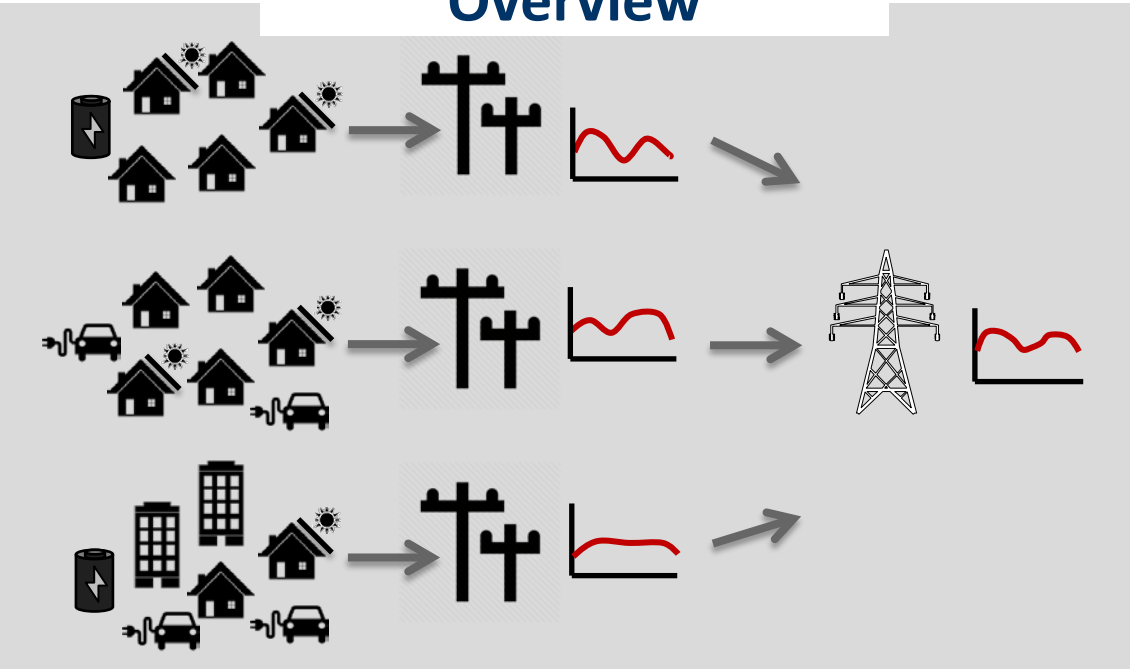
Keep standards update with HQ particularities

- PRC-024 (Quebec frequency and voltage curves)
- IEEE 1547 & P2800 (inverter performances)
- TPL, D1, MOD-032, …



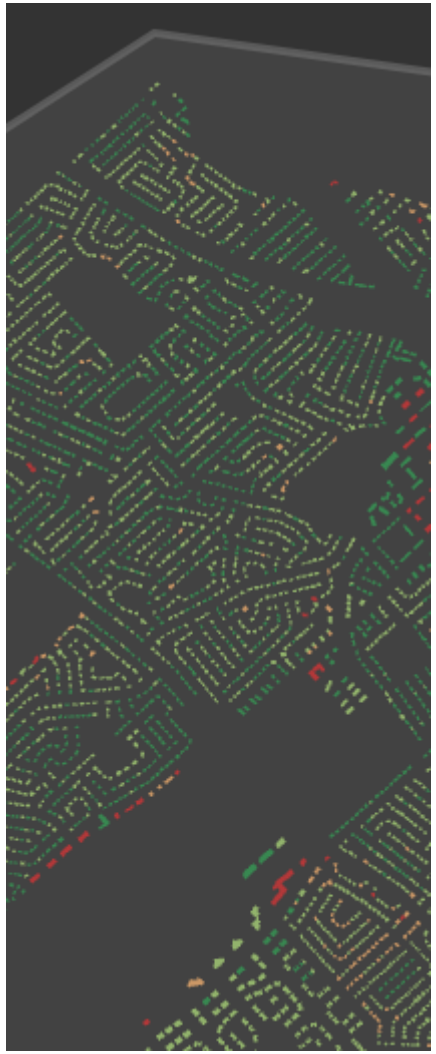
Bottom-up view of our system : SCENARIO projet

Overview

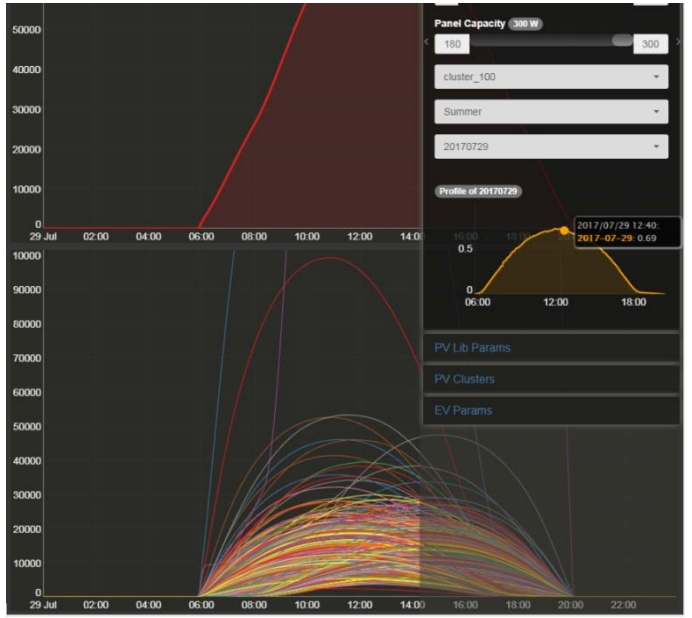


Technologies modeled









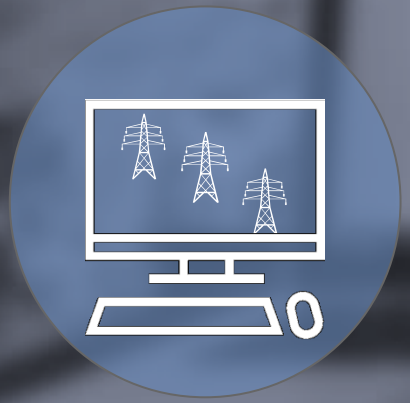
Non-wires solutions

Currently, from the transmission point of view, the uncertainty of DER (control, customers involvement, …) makes non-wires solutions financial viability difficult to assess compared to classical solutions (lines, transformers). But there's definitly value.



Studies realised so far

- Use of DER prior to UFLS and UVLS actions
- Massive storage deployment as a local grid reinforcement



SCENARIO project enhancement

The tool aimes to have T&D solutions optimization functions (2023+)

DER as a solution

- Lifetime of equipements: Traditional -vs- DER
- Minimal quantity required to obtain value
- To have an actual value:
  - Reliability
  - Control
  - Immutability
  - Security

Conclusion

- Our generation is 99% renewable : no decarbonization program
- DER are coming for sure but faster EV and slower PV adoption
- A lot of work is going on to learn and mitigate the impacts on the system (T&D)
- New bottom-up tools and new technical requirements will support planning in this new era
- Non-wires solutions is part of the global answer



Contact:
Nicolas Compas
(compas.nicolas@hydro.qc.ca)

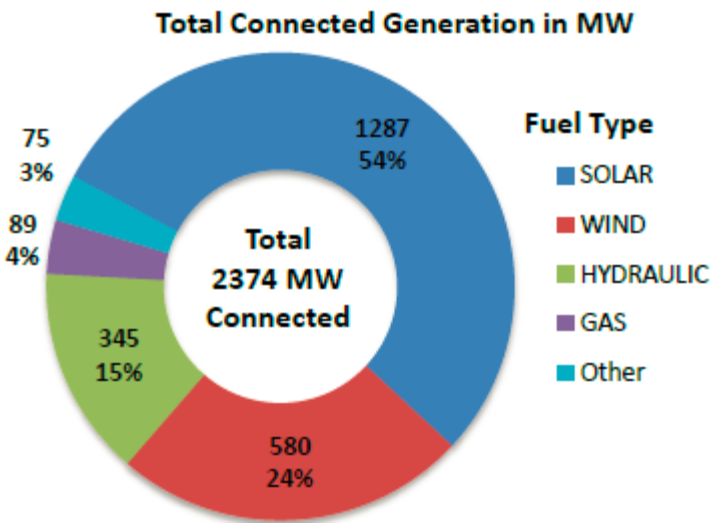
Hydro One Distributed Energy Resources Update

Adnan Akhtar, P.Eng.

Supervising Network Management Engineer

Distributed Energy Resources

- Hydro One's DER Connections
- RESOP and FIT (2008 to ~2018)
  - Wind farms
  - Solar farms
  - Biomass
  - Hydro-electric



- ~4,000 MW of total connected DER in Ontario

Distributed Energy Resources

- Post FIT (fall 2018)
  - Incentive is now to displace load and/or reduce peak demand
  - Combined Heat and Power (CHP)
  - Battery Energy Storage System (BESS)
  - Load Displacement Generation (LDG)
  - Non Parallel Load Displacement Generation (NPLDG)

DER Impact on the System

- Steady State
  - DER impacts power flows; whether it is exporting or not.
  - Power Quality - in-rush, flicker
  - Intermittent generation – voltage swings and impact on voltage regulation
  - Potential to cause (excessive) reverse flow
    - TS / DS / RS Transformer limits
    - Conductor thermal limits
    - Regulator controller upgrades for reverse flow
    - Metering upgrades for reverse flow
  - May not always be operating as we'd want them to;
    - On/Off during peak/min loading

DER Impact on the System

- Short Circuit
  - All DER connecting in parallel contribute SC current
  - May trigger upgrades to; Reclosers, Fuses
  - 27.6kV systems facing TSC constraints
  - Discussions with Tx AM, Special Studies, DER proponents
    - Reactor at TS transformer
    - Bus-tie reactors
    - Reactor at DER Facility
    - CLiP Fuses

DER Impact on the System

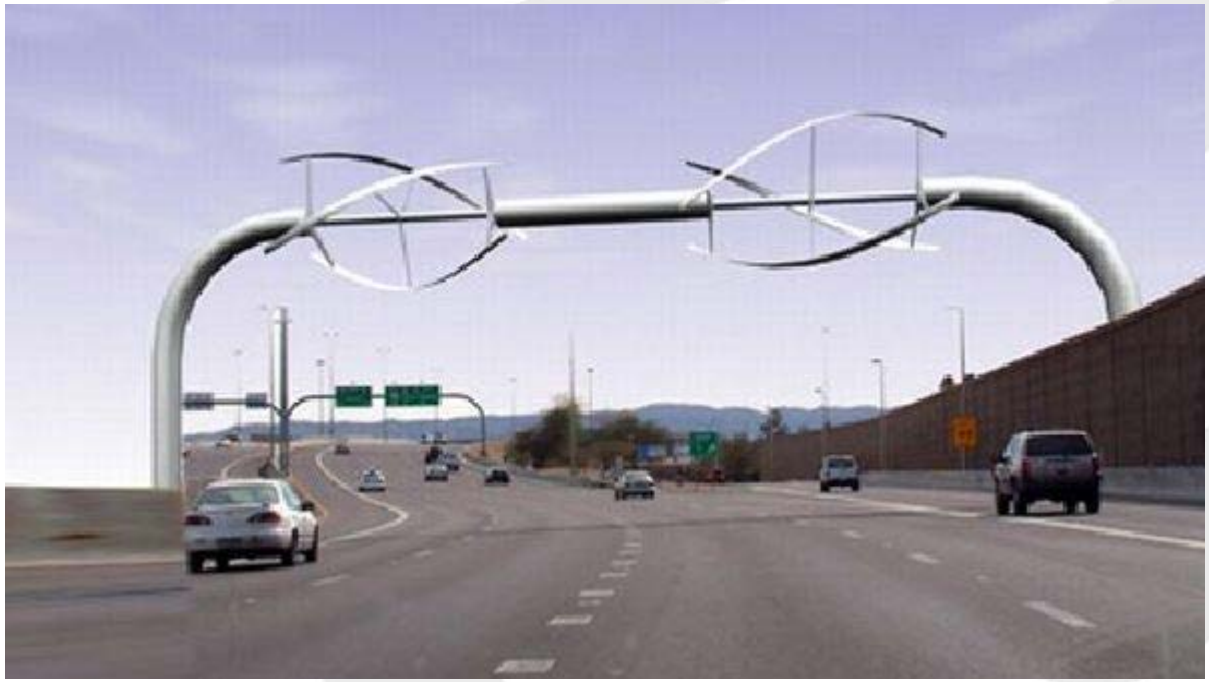
- Protections
  - DER protections must coordinate with HONI Dx system protections
  - Larger projects typically require Tele-protections – direct transfer t
  - Radially supplied Transmission Stations may need HVTT from Transmission Network
  - Can result in upgrades to relays and reclosers at HONI station or inline reclosers on the feeder

Table 10: Typical Interconnection Protections for Three Phase DG Facilities

Function Requirement	Protection Element function	Device # [14]	Synchronous	Induction	Inverter [15]	Section
Basic Anti-Islanding	Over-Voltage	59	Required	Required	Required	2.3.11, 2.3.12 iii)
	Under-Voltage	27	Required	Required	Required	
	Over-Frequency	81O	Required	Required	Required	2.3.10, 2.3.12 iii)
	Under-Frequency	81U	Required	Required	Required	
Tele-protections	Transfer Trip Receive	TTR	as per Section	as per Section	as per Section	2.3.13
	DGEO/LSBS	DGEO	as per Section	as per Section	as per Section	2.3.14
Other passive Anti-islanding (Application Specific)	Rate of Change of Frequency (ROCOF)	81R	≤ 500 kW	≤ 500 kW	Not required [16]	2.3.12 iv)
	Vector Surge	78	≤ 500 kW	≤ 500 kW	Not required [16]	
	Directional Reactive Power Relay [17]	32R	≤ 500 kW [17]	≤ 500 kW [17]	Not required [16]	
Phase Fault Protection	Phase Over-current	50	Required	Required	Required	2.3.7
	Phase Inverse Timed Over-current [18]	51	See Note [18]	See Note [18]	See Note [18]	
	Voltage Controlled Over-current [18, 19]	51V	See Notes [18, 19]	See Notes [18, 19]	See Notes [18, 19]	
	Directional Phase Over-current [20]	67	Required [20]	Required [20]	Required [20]	
	Phase Distance [19, 20]	21	See Notes [19, 20]	See Notes [19, 20]	See Notes [19, 20]	
	Under-Voltage [21]	27	See Note [21]	See Note [21]	See Note [21]	
Ground Fault Protection	Neutral Over-current	50N	Required	Required	Required	
	Neutral Inverse Timed Over-current [18]	51N	See Note [18]	See Note [18]	See Note [18]	
	Directional Neutral Over-current [20]	67N	Required [20]	Required [20]	Required [20]	
	Ground Distance [19, 20]	21N	See Notes [19, 20]	See Notes [19, 20]	See Notes [19, 20]	
	Under-Voltage [21]	27	See Note [21]	See Note [21]	See Note [21]	
	Ground Overvoltage [22]	59G	Required [22]	Required [22]	Required [22]	

- Monitoring
  - Any DG ≥250kW requires Full Monitoring data sent to NMS (DMS)

The Future of DER



- We continue to see demand for DER connections;
  - Load displacement and Peak Shaving
  - Future possibilities – anything that can store energy
  - Community Micro-Grids

DER Planning Challenges

- Allowable limits of DER is currently planned based on the few hours of the year that are worst case scenario.
  (Min Load, Max Generation)
- HONI assets are underutilized rest of the year
- DERMS could control DER output
  - Allow us to connect more DER and reduce output during the few critical hours of each year
- Increased DER penetration
  - Increases fault levels
  - Increases risk of post contingency voltage stability

Technical Interconnection Requirements (TIR) Update

- The TIR is our technical interconnection requriements document -available on Hydro One's public website (https://www.hydroone.com/business-services/generators/technical-requirements)
- We are currently revising the document to review the impact of:
  - Newer DER Voltage ride-through requirements
  - IEEE 1547-2018 & CSA 22.3 No. 9 -2019 – smart inverters
  - Reviewing transfer trip requirements
  - Requirements for load displacement and energy storage
  - Flexible hosting capacity & DERMS