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

NPCC REGIONAL STANDARDS COMMITTEE

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

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

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

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

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated January 31, 2018
NPCC Glossary of Terms, dated January 14, 2014

Introductions and Chair's Remarks

NPCC Antitrust Compliance Guidelines

Agenda Items:

1.0 Review of Agenda

2.0 RSC Meeting Minutes

3.0 Drafting Team Members and Executive Tracking Summary

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

4.0 Open Action Items

4.1 Open Action Items List

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin
5.2 Standards Efficiency Review
5.3 FERC Order No.743 Final Rule for Approving CIP-003-7
5.4 Project 2018-1 Canadian-specific Revisions to TPL-007-2
5.5 Project 2015-10 Single Points of Failure TPL-001
5.6 NPCC Goals – Approach and Process Development for DER Distribution Level Reliability Impacts

5.7 FERC Resilience Proceeding Comments

6.0 NERC Reliability Standards

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

6.1 Currently Posted Projects

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

6.2 Ballot History (Since last RSC Meeting)

6.3 Comment Form History (Since last RSC Meeting)

7.0 NERC Drafting Team Nominations

7.1 Currently Posted Drafting Team Vacancies

7.1.1 None at this time

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)

7.2.1 None at this time

7.3 Solicitation for Informal Development Teams

7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

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

8.1 Current Activities:

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

9.0 NPCC Non-Standards

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

9.1 Directories:

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

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

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

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

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

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

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

10.0 RSC Member Items of Interest

10.1 RSC Roster

11.0 Standards Activity Post NERC BOT Approval

(Since last RSC Meeting)

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

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

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

11.4 FERC Sunshine Act Meeting Notice

11.5 FERC Open Meeting Summaries

12.0 NERC Meetings

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

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

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

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

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

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

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

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

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

12.6 Reliability Issues Steering Committee (RISC)
http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

13.0 NERC Items of Interest (Since last RSC Meeting)

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

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

13.2 Alerts

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

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

14.0 Other Items of Interest

14.1 NPCC Board of Directors Meeting (BOD) 2018

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

14.2 CAMPUT (Canadian Association of Members of Public Utility Tribunals)

14.3 FERC Technical Conference

14.4 NPCC Draft 2019 Business Plan and Budget

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2018 Meeting Dates

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

15.2 RSC 2018 Conference Call Schedule (calls can be schedule as needed) all Calls are planned to start at 10:00 a.m. (call: 415-655-0003 (USA) / 416-915-6530 (Canada), Guest Code 28840965)

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

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

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

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

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

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

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

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NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #18-1
March 7, 2018 10:00 a.m. – 4:00 p.m. CST
March 8, 2018 8:30 a.m. – 12:00 p.m. CST
Entergy Service Inc.
Conference Room TMB-134, 1st Floor
2001 Timberloch Place
Woodlands, Texas
Attire: Business Casual

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

Day 1:
Guest Code: 643704798
Password: tBkXx5*6 (82599506 from phones)

Day 2:
Guest Code: 649569271
Password: yNEPc@84 (96372184 from phones)

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated October 6, 2017
NPCC Glossary of Terms, dated January 14, 2014

	Name	Organization	Sector (s)	Day(s)	Comment
1.	Guy Zito	Northeast Power Coordinating Council		1, 2	
2.	Gerry Dunbar	Northeast Power Coordinating Council		1, 2	
3.	Ruida Shu	Northeast Power Coordinating Council		1, 2	
4.	Juan Villar	FERC	Guest	1, 2	
5.	Mike Jones	National Grid	3	1, 2	
6.	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1, 2	Via Phone
7	Quintin Lee	Eversource Energy	1	1, 2	
8.	Joel Charlebois	AESI, Inc.	Guest	1, 2	
9.	Ron Falsetti	AESI, Inc.	Guest	1, 2	Via Phone
10.	Dan Grinkevich	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1, 2	Via Phone
11.	David Ramkalwan	Ontario Power Generation, Inc.	4	1, 2	

12.	Constantin Chitescu	Ontario Power Generation, Inc.	4	1, 2	
13.	Glen Smith	Entergy Services, ~~Inc~~Inc.	4	1, 2	
14.	Michael Godbout	Hydro-Québec TransÉnergie	2	1, 2	Via Phone
15.	Laura Mcleod	New Brunswick Power Corporation	1	1	Via Phone
16.	Payam Farahbakhsh	Hydro One Networks	1	1, 2	Via Phone
17.	Ben Wu	Orange & Rockland Utilities, Inc.	3	1	
18.	Brian Robinson	Utility Services, Inc.	5	1, 2	
19.	Sean Bodkin	Dominion Resources Services	4	1, 2	
20.	Helen Lainis	IESO	2	1, 2	Via Phone
21.	Scott Berry	IESO	2	1, 2	
22.	Salvatore Spagnolo	NYPA	4	1, 2	Via Phone
23.	Michele Tondalo	The United Illuminating Company	1	1, 2	Via Phone
24.	Jim Grant	NYISO	2	1, 2	
25.	Kathleen Goodman	ISO-NE	2	1, 2	Via Phone
26.	Josh Eason	ISO-NE	2	1, 2	Via Phone
27.	David Kiguel	Independent	7	1, 2	Via Phone
28.	Vijay Puran	New York State Department of Public Service	6	1, 2	Via Phone
29.	Sean Cavote	PSEG	4	1	
30.	Latrice Harkness	NERC	Guest	1, 2	

Introductions and Chair's Remarks
Guy Zito welcomed everyone to The Woodlands Texas and Glen Smith from Entergy provided ~~a brief~~a brief safety session.

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

Agenda Items:

1.0 Review of Agenda

Guy Zito replaced agenda item 9.1.4 with Directory#1 Status of NYSRC Clarification Request.

2.0 RSC Meeting Minutes

Approval of Minutes—no additional revisions were made to the draft RSC meeting minutes of 12-7-17.
Jim Grant made the motion for approval.
Glen Smith seconded the motion.
Brian Robinson abstained.
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 put several projects into the inactive section.

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

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

4.0 Open Action Items

4.1 Open Action Items List
Action Item #1 is completed and will be removed from the open action items list.
Herb Schrayshuen made the motion to approve the posting of a 45-day comment period for the Directory Development manual contingent upon TFCP approval to post.
Sean Bodkin seconded the motion.
The motion was approved.

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 FERC Resilience Order

Guy Zito gave a presentation on Resilience.

Depending on the location and topography of the ISO, resilience needs to be considered differently.

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

Guy Zito requested all RSC members to provide their inputs on the DER by March 16, 2018.

Action Item:

Ruida Shu needs to send out a reminder email to the RSC members in regards to the DER inputs.

5.4 FERC NOPR on Supply Chain Risk Management Reliability Standards

The RSC members reviewed the FERC NOPR on Supply Chain Risk Management in Reliability Standards.

5.5 Policy on Guidelines and Technical Basis/Technical Rationale

The contents of these documents are used to show the thoughts of the drafting team.

These documents are not intended to be used for Compliance purposes.

NERC is trying to identify all G&TB documents so the stakeholder teams will be able to review if any compliance language is present.

5.6 FERC NOPR on Cyber Security Incident Reporting Reliability Standards

FERC received 25 comments from the industry and they are in the process of reviewing them.

There are concerns from the industry in regards to the amount of reporting that is required per the NOPR. (Compromise or attempt to Compromise)

5.7 Geomagnetic Disturbance (GMD) Data Request

The RSC members reviewed and discussed the GMD data request.

5.8 Standards Efficiency Review

Guy Zito provided a presentation to the RSC group on the Standards Efficiency Review.

Scott Berry from IESO also provided background for the Standards Efficiency Review.

5.9 Strategic Review of NPCC Criteria

Gerry Dunbar updated the RSC on the Strategic Review of the NPCC criteria.

The NPCC BOD has requested a strategic, high level review of the reliability need and benefit of~~for~~ the NPCC's more stringent criteria.

A draft Action Plan and a draft Scope of Work have been presented to the RCC for RCC review and comment.

The review will consider the reliability benefit of the criteria arranged by focus area (e.g. Operations, Planning, and System Protection) rather than a Directory specific or requirement-by-requirement assessment.

Subsequent to Task Force review a draft report will be developed and posted for a 30-day comment period for the RCC and RSC.

A final report for the NPCC Board will be developed and submitted to the RCC and the RSC for their consideration.

6.0 NERC Reliability Standards

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

6.1 Currently Posted Projects

Project	Comment Period End Date	Ballot Period End Date	Standards Developer

Project 2016-04 Modifications to PRC-025-1	12/13/17 (F)	12/13/17 (A)	Scott Barfield-McGinnis
Project 2015-10 Single Points of Failure TPL-001	4/9/18 (F)	4/9/18 (A)	Latrice Harkness
Revisions to the NERC Standard Processes Manual	5/3/17 (F)	5/3/17 (I)	Chris Larson
Project 2017-01 Modifications to BAL-003-1.1	12/1/17 (F)		Laura Anderson
Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards	3/7/18 (F)		Darrel Richardson
Project 2017-06 Modifications to BAL-002-2	8/9/17 (I)		Darrel Richardson
Project 2015-09 Establish and Communicate System Operating Limits	11/13/17 (F)	11/13/17 (I)	Katherine Street
Project 2017-05 NUC-001-3 Periodic Review	1/29/18 (F)		Mat Bunch
Project 2016-02 Modifications to CIP Standards CIP-012-1	12/11/17 (F)	12/11/17 (A)	Jordan Mallory Mat Bunch
Project 2017-03 FAC-008-3 Periodic Review	12/13/17 (F)		Al McMeekin
Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards	2/23/18 (F)		Laura Anderson
Project 2017-07 Standards Alignment with Registration	3/2/18 (F)		Laura Anderson
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final			

Project 2016-04 Modifications to PRC-025-1:
The standard has been approved by the BOT and it will be filed after the March SC meeting.

All current and pending periodic review projects will not go to BOT for approval until the Standard Efficiency Review team finishes their review since there may be opportunities to retire standards during the Standard Efficiency Review.

Project 2015-10 Single Points of Failure TPL-001:
The project is posted for an additional comment period and ballot through April 9th.
Industry Webinar scheduled for March 22, 2018.
SDT will meet in May to address comments.

Revisions to the NERC Standard Process:
Nothing to report.

Project 2017-01 Modifications to BAL-003-1.1:
Two separate SARS were submitted.
The drafting team is looking to merge them.
The goal is to present final SAR to SC in April.
Looking to solicit ~~for~~ additional generator representatives.

Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards:

Ballot closes March 7.
The plan is to present the standard to the BOT in May.
Making small modification based on Periodic Review which include a clarified footnote to the PER standard.

Project 2017-06 Modifications to BAL-002-2:
Very straight forward; 2 directives to address concerning time error corrections; possibly could go to BOT in August. Going to the SC in March for posting.

Project 2015-09:
There are multiple ~~different~~ viewpoints on how to handle revisions to the SOL definition.
The SDT is looking to post the new redline in April 2018 for comments.
Ready to post revised FAC standards in April including a revised SOL definition. ~~which~~ FERC ~~'s~~ has been supportive of the SDTs direction~~s~~.
The drafting team is not moving forward with SOL exceedance definition.

Project 2017-05 NUC-001-3 Periodic Review:
NUC is coming to a close as far as finalizing recommendations (look for it on the April or May SC Agenda) Note on Periodic Reviews: Not~~hing is~~ going to the BOT for final approval~~affirmations and recommendation~~ until the SER project is finished.

Project 2016-02 Modifications to CIP Standards CIP-012-1:
CIP-002-6, Definition of Control Center and CIP-012-1 will be posted after the March 14th, 2018 Standards Committee Meeting.~~The standard is up for ballot after the SC meeting CIP 2, 12, and new Control Center Definition approval.~~.

Formatted: Superscript

Project 2017-03 FAC-008-3 Periodic Review:
Project is posted on the March SC agenda, but it will not go the BOT until Standard Efficiency Review is completed.

Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards:
Just met to review comments. Planning~~Looking~~ to present ~~take~~ to the SC in April for approval.

Project 2017-07 Standards Alignment with Registration:
SAR just closed on Mar 2. Currently planning to present to the SC for approval in April.

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

7.0 NERC Drafting Team Nominations

7.1 Currently Posted Drafting Team Vacancies
7.1.1 None at this time
7.2 Closed Drafting Team Nominations (Since last RSC Meeting)

7.2.1 None at this time

7.3 Solicitation for Informal Development Teams

7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

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

8.1 Current Activities:

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

The drafting team convened on October 25-26. 2017 and held two conference calls to review and answer all comments submitted by the industry.

All responses to the industry comments ~~are~~ were posted onto the NPCC website on January 30, 2018.

9.0 NPCC Non-Standards

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

Gerry Dunbar updated the RSC on Criteria Services activities.

9.1 Directories:

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

RAS Implementation/Transition
TFSS has requested development of a NPCC Glossary term that will capture a protection system that does not conform to the definition of a RAS, yet there is potential to impact outside the Area and the control system should therefore be subject to the regional review process in D#7.
TFCP has expressed concern over a protection system that meets one of the exclusions in the RAS definition but still provides broader system performance benefits.
TFCP and NPCC Staff drafting a definition for a NPCC SPS that will satisfy both of these concerns.

9.1.2 A-10 *Classification of BPS Elements* (status of TFCP/CP-11review).

A revised Phase 2 Action Plan was approved by the RCC on Feb. 28.
The Action Plan was revised to incorporate comments received at the December RCC meeting and now has a milestone to achieve RCC endorsement of a preferred methodology by December 2018.
Development of Test Plans for proposed Methodologies #1, #2 and #3.
CP-11 has agreed on testing assumptions including 1) identification of Major Interfaces (inter and intra) 2) level of stress on Major Interfaces 3) performance requirements.
CP-11 is currently finalizing base cases in order to begin testing during March, April and May.
CP-11 is meeting twice a week via WEBEX to address testing issues and to further develop other concepts.

There is an Interim Deliverable in the Action Plan to present the TFCP and the TFSS with the 1st iteration of the~~our~~ testing results for Task Force review by June 30.
The TFCP is developing Selection Criteria for the method selection for review and approval by the RCC. The criteria ~~which~~ will be utilized by the RCC in evaluating a recommended methodology.

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

An Open Process posting of D#2 has recently concluded and TFCO anticipates addressing all comments and presenting a revised D#2 to the RCC in May for approval.
Directory #2 criteria ~~has~~have been reformatted into NERC style requirements.
TFCO Working Group CO-1 continues its reformatting and updating of the criteria in Directory #5.

9.1.4 Directory#1 Status of NYRC Clarification Request.

The TFCP has developed a draft response to the NYSRC for Clarification. The Request pertains to language in the planning table of D#1 (Table 1). Since the TFCO shares jurisdiction over D#1 the TFCO has also reviewed and indicated concurrence with the draft TFCP response.
TFCP anticipates approving an Open Process posting of the draft response to the NYSRC Request for Clarification at its meeting on 3/19.

9.1.5 Directory Manual --- Periodic Review and Incorporate A-01
The RSC approved a draft revised Directory Manual for Open Process posting pending concurrence by the TFCP. The revised Manual now contains relevant sections of NPCC document A-01 in advance of formally retiring the A-01.
Subsequent to comment consideration the revised Directory Manual will be presented to the RSC for approval and a retirement recommendation will be presented to the RCC for the A-01.
Gerry Dunbar thanked Michael Jones, Quintin Lee and Herb Schrayshuen for their assistance developing the revised Directory Manual.

10.0 RSC Member Items of Interest

10.1 RSC Roster

11.0 Standards Activity Post NERC BOT Approval

(Since last RSC Meeting)

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

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

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

11.4 FERC Sunshine Act Meeting Notice
11.5 FERC Open Meeting Summaries

12.0 NERC Meetings

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

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

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

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

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

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

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

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

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

12.6 Reliability Issues Steering Committee (RISC)
http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

13.0 NERC Items of Interest (Since last RSC Meeting)

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

13.1.1 There has been one 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 Compliance Committee (CC) Schedule

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

14.2 NPCC Board of Directors Meeting (BOD) 2018

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

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2018 Meeting Dates

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

15.2 RSC 2018 Conference Call Schedule (calls can be schedule as needed) all Calls are planned to start at 10:00 a.m. (call: 415-655-0003 (USA) / 416-915-6530 (Canada), Guest Code 28840965)

January 19	February 2	February 16
March 23	April 6	April 20
May 4	May 18	June 22
July 13	July 27	August 11
September 14	September 28	October 26
November 9	November 23	December 21

The meeting is adjourned at 10:30 AM on March 8, 2018.

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
2013-03	Geomagnetic Disturbance Mitigation	Standard	Per-Anders Lof Rui Sun Louis Gibson	National Grid Dominion Hydro Quebec	781-907-5581	per-anders.lof@nationalgrid.com
2015-03	Periodic Review of System Operating Limit Standards	Standard	Dean Laforest Sam Jager	ISO-NE IESO		
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.		
2016-03	Cyber Security Supply Chain Management	Standard	Norm Dang David Bryan Gayle	IESO Dominion Resource Services, Inc.		
2016-04	Modifications to PRC-025-1	Standard	Juan Alvarez	Utility Services		
2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	Standard	Tim Kucey	PSEG Fossil, LLC		
2017-01	Modifications to BAL-003-1.1	Standard				
2017-02	Modifications to Personnel Performance, Training, and Qualifications Standards - PER-003, PER-004	Standard				
2017-06	Modifications to BAL-002-2	Standard				
2017-07	Standards Alignment with Registration	Standard	Jill Loewer	Utility Services		
2018-01	Canadian-specific Revisions to TPL-007-2	Standard				

Source = NERC Standard Drafting Team Rosters - July 2017

NPCC Directory Executive Tracking Summary

Revised: **5/12/2018** Further details regarding the individual documents may be found at: https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

Line No.	Type	Document	Description	Latest Revision	Comments	Status
1	Regional Standard	PRC -006-NPCC-1	Automatic UFLS	Feb-12	Previous Comment Period Concluded 10/16.	PRC -006-NPCC -1 Posted for 45 Day Comment April 16 2018 to May 31 2018.
2	Directory	Directory Manual	Emergency Operation	Jun-09	Directory Manual Updated to Include A-01	NPCC Directory Development and Revision Manual Posted for 45 Day Comment April 25 to June 9.
3	Procedure	C-46	Procedure for Operations Planning Model Data Exchange	New	TFCO Proposing New C-46	C-46 Posted for 45 Day Comment April 23 2018 to June 7.

NPCC Directory Executive Tracking Summary

Revised: 5/12/2018 Further details regarding the individual documents may be found at:

	Document	Developed From	Title of Directory	Responsible Task Force	Latest Version	Comments	Status
1	Directory #1	Criteria A-2	Design and Operation of the Bulk Power System	TFCP	Oct-15		
2	Directory #2	Criteria A-3	Emergency Operations	TFCO	Jun-09	D#2 Criteria Reformatted into NERC Style Requirements.	Pending RCC and Full Member Ballot Approval.
3	Directory #3	Criteria A-4	Maintenance Criteria for Bulk Power System Protection	TFSP	Jun-09		Directory#3 retired effective April 1st, 2015 coinciding with the enforcement date of PRC -005-2.
4	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	TFSP	Oct-15		Currently Under TFSP Review.
5	Directory #5	Criteria A-6	Reserve	TFCO	Oct-12		TFCO Working Group CO-1 Currently Reviewing Reformatted Draft of Directory#5.
6	Directory #6		Regional Reserve Sharing		Apr-12		
7	Directory #7	Criteria A-11	Special Protection Systems	TFSP	Jul-13	TFSP Reviewing D#7 Criteria; TFCP Coordinating Review of D#7 Attachment B.	Currently Under TFCP and TFSP Review.
8	Directory #8	Criteria A-12	System Restoration	TFCO	Oct-17	Pending TFCO/TFSP Review Task Forces Proposing Further Criteria Revisions.	TFCO revisions approved on October 6, 2017.
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	TFCO	Dec-11		NPCC Full Members approved retirement of D#9 and D#10 pending full enforcement of MOD-25-2. (July 2019).
10	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	TFCO	Dec-11		See D#9.
11	Directory#11	Criteria A-15	Disturbance Monitoring	TFSP	Oct-16		D#11 Approved October 2016.
12	Directory#12	N/A	UFLS	TFSS	Oct-12		
13	A-10 Criteria	N/A	Classification of BPS Elements	TFCP	Dec-09	RCC Approved CP-11 Proposed Methodolgies for Testing in Phase 2.	Testing of Proposed Methodologies Underway.
14	A-01 Criteria	N/A	Criteria for Review and Approval of Documents	TFCP	Oct-17	Proposed for Retirement	Posted for Comment -A01Incorporated in Directory Manua
15	C-46 Procedur	N/A	Procedure for Operations Planning Model Data Exchange	TFCO	New	TFCO Proposing New Document	Posted for Comment

NPCC Directory Criteria Clarifications

Revised: 5/12/2018 Further details regarding the individual documents may be found at: https://www.npcc.org/Standards/Directory%20Interpretations/Forms/Public%20List.aspx

Line No.	Document	Title of Directory	Date Final	Task Force Review	Posted Open Process?	RCC Approval	Comments	Status
1	Directory #8 Interpretation	System Restoration	6/18/2012	TFCO	N/A	N/A	Interpretation on behalf of the NYSRC	Complete
2	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	8/28/2012	TFSP	N/A	N/A	Interpretation on behalf of Bangor Hydro	Complete
3	Directory #3 Interpretation	Maintenance Criteria for Bulk Power System Protection	12/14/2012	TFSP	N/A	N/A	Interpretation on behalf of Con Ed	Complete
4	Directory #3 Interpretation	Maintenance Criteria for Bulk Power System Protection	2/15/2013	TFSP	N/A	N/A	Response Clarified - Interpretation on behalf of Acumen Engineered Solutions	Complete
5	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	10/25/2013	TFSP	N/A	N/A	Interpretation on behalf of Hydro One Networks	Complete
6	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	3/4/2015	TFSP	Yes	Yes	Interpretation on behalf of IESO-MACD	Complete.
7	Directory#8 Clarification	System Restoration	12/1/2015	TFCO	Yes	Yes	Clarification on Behalf of OPG.	Complete.
8	Directory#5 Clarification	Reserve	9/7/2016	TFCO	Yes	Yes	Clarification on Behalf of the NYISO.	Complete
9	Directory#1 Clarification	Design and Operation of the BPS	9/7/2016	TFCP	Yes	Yes	Clarification on Behalf of New Brunswick	Complete
10	Directory#4 Clarification	System Protection Criteria	12/2/2016	TFSP	Yes	Yes	Clarification on Behalf of Eversource	Complete
11	Directory #4 Clarification	System Protection Criteria	12/5/2017	TFSP	Yes	Yes	Clarification on Behalf of Eversource.	Complete
12	Directory#1 Clarification	Design and Operation of the BPS	N/A	TFCP/TFCO	Yes	Pending	Clarification on Behalf of NYSRC	Pending RCC Approval

5/12/2018

Filing Period	Filing Due	Filing Submitted	Comments
October 1 to December 31, 2012	3/1/2013	3/1/2013	This filing is NPCC's initial quarterly filing covering the October 1 to December 31, 2012 period and covers the changes to the NPCC Criteria as a result of voting by the Full Members of NPCC.
January 1 to March 31, 2013	6/1/2013	N/A	No changes were made during the refeenced period which required filing.
April 1 to June 30, 2013	9/1/2013	N/A	No changes were made during the referenced period which required filing.
July 1 to September 30, 2013	12/1/2013	11/25/2013	Revisions to D#7 and D#12 approved by the Full Members on 7/9/2013.
October 1 to December 31, 2013	3/1/2014	N/A	No changes were made during the referenced period which required filing.
January 1 to March 31, 2014	6/1/2014	N/A	No changes were made during the referenced period which required filing.
April 1 to June 30, 2014	9/1/2014	N/A	No changes were made during the referenced period which required filing.
July 1 to September 30, 2014	12/1/2014	N/A	No changes were made during the referenced period which required filing.
October 1 to December 31, 2014	3/1/2015	2/23/2015	(1) 10/15/14 NPCC Full Members approved retirement of D#3 effective 4/01/15 coinciding with enforcement date of PRC -005-2
	3/1/2015	N/A	(2) 10/6/14 the RSC approved revisions to the Directory Manual which incorporated cost considerations into the Manual.
January 1st to March 31st 2015	6/1/2015	N/A	No changes were made during the referenced period which required filing.
April 1st to June 30th 2015	9/1/2015	N/A	No changes were made during the referenced period which required filing.
July 1 to September 30, 2015	12/1/2015	11/25/2015	Revisions to D#1 and D#4 approved by the Full Members on 9/30/2015.
October 1 to December 31, 2015	3/1/2016	N/A	No changes were made during the referenced period which required filing.
January 1st to March 31st, 2016	6/1/2016	N/A	No changes were made during the referenced period which required filing.
April 1 to June 30, 2016	9/1/2016	N/A	No changes were made during the referenced period which required filing.
July 1 to September 30, 2016	12/1/2016	N/A	No changes were made during the referenced period which required filing.
October 1 to December 31, 2016	3/1/2017	2/28/2017	Directory#11 approved by Full Members October 2016.
January 1st to March 31st 2017	6/1/2017	N/A	No changes were made during the referenced period which required filing.
April 1 to June 30, 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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

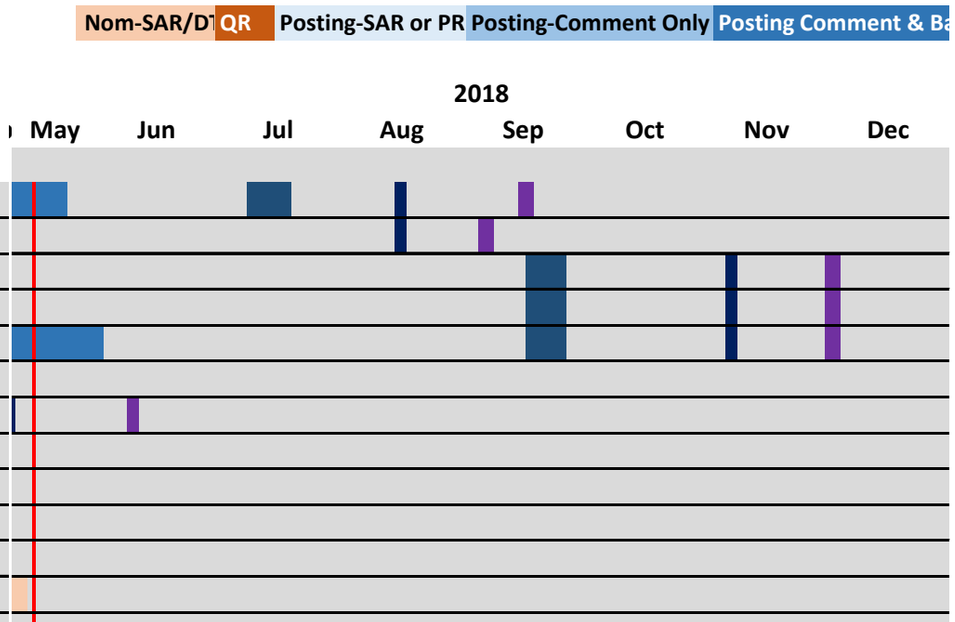
SUMMARY
Tutorial Video (11 min)
Click here to report errors or issues

Updated: 5/16/2018

Nom-SAR/DT | QR | Posting-SAR or PR | Posting-Comment Only | Posting Comment & Ba

HOME

U	Project (Filter)	DO NOT SORT (Filtering Ok) Deliverables (Filter)	Early/(Late) Days (Filter)	Baseline/ Current (Filter)
R	2015-09 - Establish and Communicate System O	FAC-010-3, FAC-011-3, and FAC-014-2	(98)	Current
Ye	2015-10 - Single Points of Failure TPL-001	TPL-001-5	(113)	Current
R	2016-02 - Modifications to CIP Standards	Directives, Control Center Comm Nets	(335)	Current
R	2016-02 - Modifications to CIP Standards	Address TO Control Centers Performin	(335)	Current
R	2016-02 - Modifications to CIP Standards	Address all remaining V5TAG issues: C	No schedule	N/A
R	2017-01 - Modifications to BAL-003-1	BAL-003-2		Proposed
Ye	2017-02 - Modifications to Personnel Performan	PER-003-2, retire PER-004-2	24	Proposed
R	2017-03 - Periodic Review of FAC-008-3 Standar	Periodic Review Recommendations		N/A
R	2017-04 - Periodic Review of Interchange Sched	Periodic Review Recommendations		N/A
R	2017-05 - Project 2017-05 NUC-001-3 Periodic R	Periodic Review of NUC-001-3 Standar		N/A
R	2017-06 - Project 2017-06 Modifications to BAL-	BAL-002-3		Proposed
Ye	2017-07 - Stds Alignment with Registration	Standards with PSE, IA, or LSE		Proposed
Ye	2018-01 - Canadian-specific Revisions to TPL-00	TPL-007-3		Proposed



Project	Project Name	Status	Comments	Deliverable	Deadline	Priority in RSDP, click to see applicable	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	A meeting is scheduled for May 7-9, 2018 in Atlanta. The team has been working on finalizing FAC-011 Mapping and Rationale documentation as well as VRF/VSL justifications for FAC-011, 014, and 015. There are	FAC-010-3, FAC-011-3, and FAC-014-2	N/A	Footnote 7, Medium	N/A	N/A	N/A	N/A	Darrel Richardson	Ken Lanehome	FAC-010-3, FAC-011-3, and FAC-014-2	4/25/2018
2015-10	Single Points of Failure TPL-001	Responding to Comment	The second comment period with ballot that failed ended on April 23, 2018. The team meets May 8-10, 2018 to respond to comments. Consensus is to remove the P8 category from the standard.	TPL-001-5	N/A	Footnote 8, High	N/A	2 directives at P40 & P89 (Click this link for FERC Order)	N/A	N/A	Latrice Harkness	Mark Pratt	TPL-001-4	5/16/2018
2016-02	Modifications to CIP Standards	Working to Comment Posting	Nominations for additional team members is open through May 23, 2018 concerning virtualization.	Address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Mat Bunch & Jordan Mallory	Ken Lanehome, Ash Mayfield, and Kirk	CIP Stds. - Unknown	4/25/2018
2016-02	Modifications to CIP Standards	Posted	CIP-012 and the proposed control center definition are out for comments and separate ballots until April 30. The team meets in Austin, TX on May 8-11, 2018 to address comments.	Directives, Control Center Comm Nets (CIP-012-1)/ Control Center definition	N/A	Footnote 8, High	N/A	2	N/A	N/A	Mat Bunch & Jordan Mallory	Ken Lanehome and Ash Mayfield	CIP-012-1	4/25/2018
2016-02	Modifications to CIP Standards	Posted	CIP-002 and the proposed control center definition are out for comments and separate ballots until April 30. The team meets in Austin, TX on May 7-11, 2018 to address comments.	Address TO Control Centers Performing Transmission Operator (TOP) Obligations.	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Mat Bunch & Jordan Mallory	Ken Lanehome and Ash Mayfield	CIP-002-5.1a	4/25/2018
2017-01	Modifications to BAL-003-1	SDT Development	At the last Standards Committee (SC) meeting, the SC approved additional Standard Drafting Team members to represent the generation segment to cover the potential extended applicability to generators. The SC also accepted a Standard Authorization Request (SAR) that consolidates two	BAL-003-2	N/A	Footnote 8, Medium	N/A	N/A	N/A	N/A	Darrel Richardson	Amy Casuscelli & Linda Lynch	BAL-003-1	4/25/2018
2017-02	Modifications to Personnel Performance, Training, and Qualifications Standards	Pending Regulatory F	Retirement of PER-004 and modification of PER-003 were approved by the Board May 2018.	PER-003-2, retire PER-00	N/A	Footnote 8, Medium	N/A	N/A	N/A	N/A	Darrel Richardson	Mike Brytowski	PER-003-1 & PER-004-2	5/16/2018
2017-03	Periodic Review of FAC-008-3 Standard	On Hold	The periodic review team delivered their review recommendation to the SC in March 2018. The recommendation is to reaffirm with an action to revise, but at a later time. No action will be taken or archiving of the PTS	Periodic Review Recomn	N/A	Footnote 9, Low (was Medium previously)	N/A	N/A	N/A	N/A	Al McMeekin	Mark Pratt	FAC-008-3	4/24/2018
2017-04	Periodic Review of Interchange Scheduling and Coordination Standards	On Hold	The response to comments are complete. Comments were in favor of the recommendations being made by the team which is to retire one standard and drop terms which are unclear in the standards. Periodic Review of subset INT Standards will provide the Standards Efficiency Review Team (SER) (Gary Nolan is the contact person) with the initial recommendations of the INT periodic review team, as well as all associated documents this week. No future meetings or postings expected for now. Project 2017-04 will then be placed on hold pending SER team recommendations/findings. No recommendations have been made to the Standards Committee.	Periodic Review Recomn	N/A	Footnote 9, Low (was Medium previously)	N/A	N/A	N/A	N/A	Laura Anderson	Charles Yeung	INT-004, INT-006, INT-009, and INT-010	4/25/2018
2017-05	Project 2017-05 NUC-001-3 Periodic Review	Standing Review Tear	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 anticipate delivering the recommendation to the SC at their May 2018 meeting.	Periodic Review of NUC-1	N/A	Footnote 9, Low (was Medium previously)	N/A	N/A	N/A	N/A	Mat Bunch	Amy Casuscelli and Colby Bellville	NUC-001-3	4/25/2018
2017-06	Project 2017-06 Modifications to BAL-002-2	Posted	The initial ballot is open until May 7, 2018. Currently there are no issues submitted by industry. The project doesn't have a baseline yet due to the drafting team believing there is a simple fix that is already complete and pending the approval processes. The team will setup the next meeting once the initial ballot completes.	BAL-002-3	N/A	Footnote 8, Medium	N/A	N/A	N/A	N/A	Darrel Richardson	Ken Lanehome	BAL-002-2	4/25/2018
2017-07	Stds Alignment with Registration	Responding to Comm	Project 2017-07 Standards with Alignment will ask the SC to accept the project SAR at the April 2018 SC meeting. A standards development project will commence once SC approves SAR and the drafting team is	Standards with PSE, IA, o		N/A					Laura Anderson	Mike Brytowski		5/16/2018
N/A	N/A	N/A	N/A	Mat Bunch	N/A	N/A	N/A	N/A	N/A	N/A	Mat Bunch	TBD	TPL-007-2	5/16/2018

Project	**2015-09**
Project Name	Establish and Communicate System Operating Limits
Status	Working to Additional Ballot
Comments	A meeting is scheduled for May 7-9, 2018 in Atlanta. The team has been working on finalizing FAC-011 Mapping and Rationale documentation as well as VRF/VSL justifications for FAC-011, 014, and 015. There are questions about the retirement of FAC-010 because there are existing standards that reference the Planning Horizon SOLs/IROLs that would be going away with the proposed retirement.
Deliverable	FAC-010-3, FAC-011-3, and FAC-014-2
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 7, Medium
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Darrel Richardson
PMOS Liaison	Ken Lanehome
Affected Standards	FAC-010-3, FAC-011-3, and FAC-014-2
Last Updated	4/25/2018

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review			4/4/2016	4/14/2016		Not needed	
SP1 - SAR/PR/WP Posting 1	8/20/2015	9/21/2015	8/20/2015	9/21/2015			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	7/14/2016	8/12/2016	7/8/2016	8/7/2016	(6)		
CP2 - Comment Period 2							

CIB - Com/Ballot 1 (Initial)	9/29/2017	11/13/2017	9/22/2017	11/5/2017	(7)		Posting date changed see notes 8/10 and 8/25.
CAB - Com/Add Ballot 2	4/9/2018	5/24/2018	1/17/2018	3/2/2018	(82)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	7/9/2018	7/19/2018	4/2/2018	4/12/2018	(98)		
PTB - Present to BOT	8/15/2018	8/17/2018	5/1/2018	5/3/2018	(106)		
Filing - Filing with Regulators	9/15/2018	9/18/2018	6/1/2018	6/4/2018	(106)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Explain delay	5/1/2016	The apparent delay in the project is due to missing an earlier update to the PMOS Annual Project Calendar. Baseline Schedule has not been adjusted.
Developer change	1/13/2017	Transition from Lacey Ourso to Darrel Richardson.
Developer change	4/1/2017	Added Al McMeekin to the project.

Project	**2015-09**	**Home**
Project Name	Establish and Communicate System Operating Limits	
Status	Other	
Comments	The IROL portion of the project has been placed on hold pending additional information.	
Deliverable	IROL Stds.	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Al McMeekin	
PMOS Liaison	Ken Lanehome	
Affected Standards	TBD - On Hold	
Last Updated	9/5/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

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

Project	**2015-10**
Project Name	Single Points of Failure TPL-001
Status	Responding to Comment
Comments	The second comment period with ballot that failed ended on April 23, 2018. The team meets May 8-10, 2018 to respond to comments. Consensus is to remove the P8 category from the standard.
Deliverable	TPL-001-5
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	2 directives at P40 & P89 (Click this link for FERC Order)
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Latrice Harkness
PMOS Liaison	Mark Pratt
Affected Standards	TPL-001-4
Last Updated	5/16/2018

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	11/12/2015	12/1/2015	1/18/2016	2/1/2016	67		
Nominations - DT	7/22/2016	8/5/2016	7/25/2016	8/8/2016	3		
QR - Quality Review			5/30/2016	6/9/2016			
SP1 - SAR/PR/WP Posting 1	11/12/2015	12/17/2015	11/12/2015	12/17/2015			
SP2 - SAR/PR/WP Posting 2	5/26/2016	6/24/2016	6/15/2016	7/15/2016	20	Expanded Scope	
CP1 - Comment Period 1	4/25/2017	5/24/2017	4/25/2017	5/24/2017		Other	Team added informal comment period

CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/8/2017	10/23/2017	7/5/2017	8/18/2017	(65)		Held at 9/7 to stagger 2013-03 and 2015-09.
CAB - Com/Add Ballot 2	2/23/2018	4/23/2018	10/18/2017	12/1/2017	(128)		Period extended from 4/9 to 4/23 due to changes
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	5/1/2018	5/10/2018	1/8/2018	1/17/2018	(113)		
PTB - Present to BOT	8/15/2018	8/17/2018	2/1/2018	2/3/2018	(195)		
Filing - Filing with Regulators	9/5/2018	9/8/2018	3/1/2018	3/4/2018	(188)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Expansion of Scope	6/14/2016	FERC directives added (P40 & P89) additional scoping in addition to industry comments following the second SAR posting. The MOD references are being updated due to some retiring
Developer change	1/13/2017	Transition from Lacey Ourso to Soo Jin Kim until a new developer is assigned.
Accept Schedule	4/27/2017	Accepted by PMOS.
Schedule deviation	6/13/2017	Baseline initial ballot of 7/5/2017 moved to 9/7/2017 due addressing comments and scope of SAR. Schedule accounts for SC not meeting in August.
Schedule Adjustment	8/10/2017	No adjustment required 2013-03, 2015-09, and 2016-02 were staggered to spread postings out.

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Posted
Comments	CIP-012 and the proposed control center definition are out for comments and separate ballots until April 30. The team meets in Austin, TX on May 8-11, 2018 to address comments.
Deliverable	Directives, Control Center Comm Nets (CIP-012-1)/ Control Center definition
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	2
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mat Bunch & Jordan Mallory
PMOS Liaison	Ken Lanehome and Ash Mayfield
Affected Standards	CIP-012-1
Last Updated	4/25/2018

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	2/10/2017	3/13/2017					
CP2 - Comment Period 2	8/14/2017	9/12/2017	12/2/2016	1/16/2017	(255)		Informal for definition
CIB - Com/Ballot 1 (Initial)	7/27/2017	9/11/2017	3/31/2017	5/15/2017	(118)		

CAB - Com/Add Ballot 2	10/27/2017	12/11/2017	8/15/2017	9/29/2017	(73)		Does not include the informal 21 day comment on Implementation Guidance ending on 12/11/2017
CAB - Com/Add Ballot 3	3/16/2018	4/30/2018			(43175)		
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	9/17/2018	9/26/2018	10/17/2017	10/27/2017	(335)		
PTB - Present to BOT	11/6/2018	11/8/2018	11/7/2017	11/9/2017	(364)		
Filing - Filing with Regulators	12/1/2018	12/4/2018	12/28/2017	12/31/2017	(338)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Archived comments	6/10/2016	Order 822 was issued on January 21, 2016. The SC authorized posting the SAR and to request nominations for additional team members at March 9, 2016 meeting. The SAR posting ended April 21, 2016 and the SDT is reviewing the comments received. A CIP Technical Conference was held on April 19, 2016 in Atlanta. Seven additional members were appointed to the SDT at the April 20, 2016 SC meeting. Initial SDT meeting May 24-26, 2016 in Atlanta.
Added CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison.
Liaison Change	3/15/2017	Updated B. Murpy and A. Gallow to K. Lanehome and A. Mayfield
Developer Change	4/1/2017	Replaced Al McMeekin with Mat Bunch and Katherine Street.
Change in Approach	6/27/2017	Team decided to create CIP-012-1 and not modiifying CIP-006 for Communcation Networks.
Developer Change	2/14/2018	Replaced Katherine Street with Jordan Mallory

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Posted
Comments	CIP-002 and the proposed control center definition are out for comments and separate ballots until April 30. The team meets in Austin, TX on May 7-11, 2018 to address comments.
Deliverable	Address TO Control Centers Performing Transmission Operator (TOP) Obligations.
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mat Bunch & Jordan Mallory
PMOS Liaison	Ken Lanehome and Ash Mayfield
Affected Standards	CIP-002-5.1a
Last Updated	4/25/2018

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							

CP1 - Comment Period 1	3/14/2017	4/11/2017					Added to schedule, reduced period - SDT needed feedback
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/14/2017	10/30/2017	12/2/2016	1/15/2017	(286)		See notes for 8/10 and 8/25.
CAB - Com/Add Ballot 2	12/5/2017	1/18/2018	3/31/2017	5/14/2017	(249)		
CAB - Com/Add Ballot 3	3/16/2018	4/30/2018	8/15/2017	9/28/2017	(213)		
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	9/17/2018	9/26/2018	10/17/2017	10/27/2017	(335)		
PTB - Present to BOT	11/6/2018	11/8/2018	11/7/2017	11/9/2017	(364)		
Filing - Filing with Regulators	12/1/2018	12/4/2018	12/28/2017	12/31/2017	(338)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Archived comments	6/10/2016	Order 822 was issued on January 21, 2016. The SC authorized posting the SAR and to request nominations for additional team members at March 9, 2016 meeting. The SAR posting ended April 21, 2016 and the SDT is reviewing the comments received. A CIP Technical Conference was held on April 19, 2016 in Atlanta. Seven additional members were appointed to the SDT at the April 20, 2016 SC meeting. Initial SDT meeting May 24-26, 2016 in Atlanta.
Added CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison.
Liaison Change	3/15/2017	Updated B. Murpy and A. Gallow to K. Lanehome and A. Mayfield
Developer Change	4/1/2017	Replaced Al McMeekin with Mat Bunch and Katherine Street.
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

Project	**2016-02**	**Home**
Project Name	Modifications to CIP Standards	
Status	Working to Comment Posting	
Comments	Nominations for additional team members is open through May 23, 2018 concerning virtualization.	
Deliverable	Address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP Exceptional Circumstances.	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, High	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mat Bunch & Jordan Mallory	
PMOS Liaison	Ken Lanehome, Ash Mayfield, and Kirk Rosener	
Affected Standards	CIP Stds. - Unknown	
Last Updated	4/25/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	3/14/2017	4/11/2017	3/14/2017	4/11/2017			
CP2 - Comment Period 2	10/6/2017	11/2/2017					Unplanned
CIB - Com/Ballot 1 (Initial)	4/19/2018	6/2/2018					
CAB - Com/Add Ballot 2							

CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	9/17/2018	9/26/2018					
PTB - Present to BOT	11/6/2018	11/8/2018					
Filing - Filing with Regulators	12/1/2018	12/4/2018					
PT - Post Approval Training							

PTS Change Control

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

Project	**2017-01**	**Home**
Project Name	Modifications to BAL-003-1	
Status	SDT Development	
Comments	At the last Standards Committee (SC) meeting, the SC approved additional Standard Drafting Team members to represent the generation segment to cover the potential extended applicability to generators. The SC also accepted a Standard Authorization Request (SAR) that consolidates two previous SARs and incorporates industry comments previously received. The drafting team met the week of April 19 and developed small groups to address the Phase 1 items identified in the SAR. The next drafting team meeting is tentatively scheduled for the first week in June. A baseline schedule is being drafted by the standards developer.	
Deliverable	BAL-003-2	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Darrel Richardson	
PMOS Liaison	Amy Casuscelli & Linda Lynch	
Affected Standards	BAL-003-1	
Last Updated	4/25/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	6/19/2017	7/3/2017	6/19/2017	7/3/2017			
Nominations - DT	7/27/2017	8/9/2017	7/27/2017	8/9/2017			Supplemental Nominations
QR - Quality Review							

SP1 - SAR/PR/WP Posting 1	6/19/2017	7/18/2017	6/19/2017	7/18/2017			By NERC RS
SP2 - SAR/PR/WP Posting 2	11/2/2017	12/1/2017	11/2/2017	12/1/2017			By NWPP FRSG
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
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	Add Linda Lynch to support Amy Casuscelli.
Accept baseline		PMOS accepted baseline project schedule.

Project	**2017-02**	**Home**
Project Name	Modifications to Personnel Performance, Training, and Qualifications Standards	
Status	Pending Regulatory Filing	
Comments	Retirement of PER-004 and modification of PER-003 were approved by the Board May 2018.	
Deliverable	PER-003-2, retire PER-004-2	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Darrel Richardson	
PMOS Liaison	Mike Brytowski	
Affected Standards	PER-003-1 & PER-004-2	
Last Updated	5/16/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							EPR SDT appointed as SDT
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/21/2017	7/24/2017	6/21/2017	7/24/2017			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	1/22/2018	3/7/2018	1/22/2018	3/7/2018			97.50%
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							

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

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Mike Brytowski accepted appointment as PMOS liaison.
Accept Baseline	1/31/2018	PMOS accepted baseline.

Project	**2017-03**	**Home**
Project Name	Periodic Review of FAC-008-3 Standard	
Status	On Hold	
Comments	The periodic review team delivered their review recommendation to the SC in March 2018. The recommendation is to reaffirm with an action to revise, but at a later time. No action will be taken or archiving of the PTS item until the Standards Efficiency Reviews are complete.	
Deliverable	Periodic Review Recommendations	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Al McMeekin	
PMOS Liaison	Mark Pratt	
Affected Standards	FAC-008-3	
Last Updated	4/24/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	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 SER team recommendations/findings. No recommendations have been made to the Standards Committee.	
Deliverable	Periodic Review Recommendations	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Laura Anderson	
PMOS Liaison	Charles Yeung	
Affected Standards	INT-004, INT-006, INT-009, and INT-010	
Last Updated	4/25/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	5/2/2017	5/15/2017	5/2/2017	5/15/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							

CP1 - Comment Period 1	1/10/2018	2/23/2018					
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Charles Yeung accepted appointment as PMOS liaison.

Project	**2017-05**	**Home**
Project Name	Project 2017-05 NUC-001-3 Periodic Review	
Status	Standing Review Team	
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 anticipate delivering the recommendation to the SC at their May 2018 meeting.	
Deliverable	Periodic Review of NUC-001-3 Standard	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mat Bunch	
PMOS Liaison	Amy Casuscelli and Colby Bellville	
Affected Standards	NUC-001-3	
Last Updated	4/25/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	5/10/2017	5/23/2017	5/10/2017	5/23/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	12/15/2017	1/29/2018	12/4/2017	1/17/2018	(11)		
CP2 - Comment Period 2							

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

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Amy Casuscelli accepted appointment as PMOS liaison.
Assign PMOS Liaison	10/12/2017	Assigned Colby Bellville to support Amy Casuscelli (new SC vice chair)

Project	**2017-06**	**Home**
Project Name	Project 2017-06 Modifications to BAL-002-2	
Status	Posted	
Comments	The initial ballot is open until May 7, 2018. Currently there are no issues submitted by industry. The project doesn't have a baseline yet due to the drafting team believing there is a simple fix that is already complete and pending the approval processes. The team will setup the next meeting once the initial ballot completes.	
Deliverable	BAL-002-3	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Darrel Richardson	
PMOS Liaison	Ken Lanehome	
Affected Standards	BAL-002-2	
Last Updated	4/25/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	6/20/2017	7/3/2017	6/20/2017	7/3/2017			
Nominations - DT	7/27/2017	8/9/2017	7/27/2017	8/9/2017			Supplemental Nominations
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/20/2017	7/20/2017	6/20/2017	7/20/2017			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	3/22/2018	5/7/2018					

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	5/30/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Ken Lanehome accepted appointment as PMOS liaison.
SAR	2/14/2018	SC accepts the final SAR.
Accept Baseline		PMOS accepted project schedule baseline.

Project	**2017-07**	**Home**
Project Name	Stds Alignment with Registration	
Status	Responding to Comment	
Comments	Project 2017-07 Standards with Alignment will ask the SC to accept the project SAR at the April 2018 SC meeting. A standards development project will commence once SC approves SAR and the drafting team is appointed by the SC. Nominations were open through May 14, 2018	
Deliverable	Standards with PSE, IA, or LSE	
Deadline		
Priority in RSDP, click to see applicable Footnote	N/A	
P81 Req (2013)		
Number of Directives		
No. of Guidances (see Note 2)		
Directionally consistent with IERP findings (See Note 5)		
Developer	Laura Anderson	
PMOS Liaison	Mike Brytowski	
Affected Standards		
Last Updated	5/16/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	8/1/2017	8/14/2017	8/1/2017	8/14/2017			
Nominations - DT	5/1/2018	5/14/2018					
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	8/1/2017	8/30/2017	8/1/2017	8/30/2017			
SP2 - SAR/PR/WP Posting 2	12/11/2017	1/9/2018	12/7/2017	1/6/2018	(4)		
CP1 - Comment Period 1	2/1/2018	3/2/2018	2/1/2018	3/2/2018			
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
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
Assign PMOS Liaison	7/27/2017	Mike Brytowski accepted appointment as PMOS liaison.

Project	**2018-01**	**Home**
Project Name	Canadian-specific Revisions to TPL-007-2	
Status	Nominations & SAR	
Comments	The SC authorized the SAR for posting on March 15 and the soliticitation of SAR drafting team members. The SAR was posted through April 30, 2018. Currently seeking to appoint SAR team members.	
Deliverable	TPL-007-3	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	N/A	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mat Bunch	
PMOS Liaison	TBD	
Affected Standards	TPL-007-2	
Last Updated	5/16/2018	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	3/30/2018	4/19/2018					
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	3/30/2018	4/30/2018					
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
Assign PMOS Liaison	4/25/2018	C. Yeung acccept to follow project.
Accept baseline schedule	TBD 6/13/2018	

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

Note 7	**2016-2018 RSDP** The following projects are planned to continue from 2015 along with any 2015 projects that are planned to be completed in that year but need additional time. As in the 2015–2017 RSDP, the approach to prioritizing Reliability Standards projects in this RSDP addressed how Reliability Standard family priorities are applied to individual projects and outstanding work. Specific elements included: (1) RISC Category Rankings; (2) regulatory directives; (3) regulatory deadlines; (4) Reliability Standard requirement candidates for retirement; (5) the IERP content and quality assessments; and (6) additional considerations (fill-in-the-blank status and five-year assessment commitments). The prioritization gave primary consideration to RISC category rankings, regulatory directives, and regulatory deadlines. Based on the application of these elements, this section prioritizes each Reliability Standard project as high, medium, low, or pending technical committee input.
Note 8	**2017-2019 RSDP** The approach to prioritizing Reliability Standards projects in this RSDP is consistent with previous RSDPs. Specific elements include: (1) RISC Category Rankings; (2) regulatory directives and deadlines; (3) Reliability Standard requirements recommended for retirement; (4) the IERP content and quality assessments; and (5) additional considerations (fill-in-the-blank status and five-year assessment commitments). The prioritization considers RISC category rankings, regulatory directives, and regulatory deadlines. Based on the application of these elements, this section prioritizes each Reliability Standard project as high, medium, low, or pending technical committee input.
Note 9	2018-2020 RSDP (DRAFT)
Note 10	

RSC Meeting #18-2, Agenda Item 4.0 Open Action Items

Item	Description	Owner	Due	Status
4.1	Michael Jones, Herb Schrayshuen and Quintin Lee volunteered to assist Gerry Dunbar on reviewing the Directory Manual to include A-01 (Five Year Periodic Review).	Gerry Dunbar	12/7/17	Completed
4.2	RSC members to have until March 16, 2018 to send any concerns or issues to Guy Zito in regards to the NPCC 2018 Spring Workshop	Guy Zito	3/16/18	Pending

DRAFT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards, Compliance, and Enforcement Bulletin

June 4–10, 2018

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

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2016-02 – Modifications to CIP Standards | CIP-012-1	Additional Ballot and Non-binding Poll	06/22/18	07/02/18
Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
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Posted for Comment			
Project	**Action**	**Start Date**	**End Date**
2018 Periodic Review Standing Review Team - Standards Grading	Comment Period	05/14/18	06/28/18
Project 2016-02 – Modifications to CIP Standards | CIP-012-1	Comment Period	05/18/18	07/02/18

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
Comment Period Open for System Operator Certification Program Survey: The Personnel Certification Governance Committee (PCGC) is in the process of reviewing the NERC System Operator Certification (SOC) program. Industry input from stakeholders related to the SOC program for potential future program development and/or improvement are being petitioned. All program participants including certified System Operators, program candidates, Continuing Education providers, and entity trainers, are encouraged to participate in the survey. An unofficial word version of the survey is available on the System Operator Certification page and the Continuing Education page of the NERC website. Please reference the word version of the survey on the website for Table 3. The PCGC will review all responses submitted by industry stakeholders.	Please submit comments using the electronic form.	04/03/18	06/15/18
Comment Period Open for Inverter-Based Resource Performance Draft Reliability Guideline: The Inverter-Based Resource Performance Task Force (IRPTF), a joint task force of the NERC Operating Committee (OC) and Planning Committee (PC), developed the draft Reliability Guideline: Inverter-Based Resource Performance. This Reliability Guideline supports recommendations in the ERO Risk Priorities Report to address potential reliability impacts of the changing resource mix by developing guidance and recommended practices for the performance of inverter-based	Submit comments via email using the comment form.	05/04/18	06/29/18

resources when connected to the bulk power system. The guideline specifies recommended steady-state and dynamic performance for inverter-based resources, and also covers a wide range of related aspects from protective functions to monitoring capability. The material presented throughout the guideline is based on extensive discussions with industry experts and members of the IRPTF. The OC and PC reviewed the initial draft of the guideline and approved it to be posted for industry comment.			
Comment Period Open for First Draft of NERC's 2019 Business Plan and Budget: The first draft of NERC's 2019 business plan and budget and the first drafts of the 2019 Regional Entities' business plans and budgets are now available on NERC's website. A presentation providing a summary of the NERC budget and ERO consolidated business plans and budgets and assessments is 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 Scott Jones, Senior Vice President, Chief Financial and Administrative Officer, and Treasurer • 2019 NERC Business Plan and Budget Overview • 2019 Combined ERO Enterprise Budgets and Assessments Overview • First Draft of NERC's 2018 Business Plan and Budget	Please direct all comments and/or questions to Erika Chanzes.	05/19/18	06/29/18

STANDARDS NEWS

NEW Registered Ballot Body Self-Select Attestation Process Begins

Appendix 3D Registered Ballot Body Criteria of the NERC Rules of Procedure states:

'Each participant, when initially registering to join the Registered Ballot Body (RBB), and annually thereafter, shall self-select to belong to one of the Segments…'

Therefore, NERC Standards staff has initiated the **2018 Annual RBB Self-select Process**.

- **June 1, 2018** – Each RBB voting member will receive a notification sent via SBS/RBB email with a link to the Standards Balloting and Commenting System (SBS) attestation page to confirm there have been no material changes in the last 12 months that affect the entity's current Segment selection(s), thus the entity continues to meet the Segment qualifications (as outlined in the qualifications in Appendix 3D: *RBB Criteria* referenced above). Each RBB member will need to log into the system first, then click the link provided to open the attestation page.
- **July 16, 2018** – Deadline for all RBB members to self-select their segment via the SBS.

For more information or assistance, contact Wendy Muller.

Quick Links

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

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

There is no additional Compliance or 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

OTHER NEWS

NEW Summer Assessment Highlights Texas Generation Shortfall, California Natural Gas Storage Constraint

NERC's *2018 Summer Reliability Assessment* finds that Texas has a generation shortfall due in part to 5,000 MW of generation retirements since last summer and that California is facing a limit on natural gas output due to Aliso Canyon storage facility constraints. NERC conducts this assessment each season to provide a high-level view of resource adequacy and to identify issues that have the potential to impact bulk power system planning, development and system analysis over the summer months. For more information, see the full announcement.

STANDARDS SUBJECT TO FUTURE ENFORCEMENT

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

U.S. Effective Date	Standard(s)
July 1, 2018	CIP-009-6 – Cyber Security — Recovery Plans for BES Cyber Systems (Requirement 2.3); CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirements 3.2, 3.2.1, 3.2.2);
	MOD-026-1 – Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions (Requirements 2, 2.1–2.1.6);

	MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions (Requirements 2, 2.1–2.1.5);
	PRC-025-2 – Generator Relay Loadability
	TOP-001-4 – Transmission Operations
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 2)
September 1, 2018	--
January 1, 2019	BAL-005-1 – Balancing Authority Control
	FAC-001-3 – Facility Interconnection Requirements
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 5, 5.1–5.2)
April 1, 2019	EOP-004-4 – Event Reporting EOP-005-3 – System Restoration from Blackstart Resources EOP-006-3 – System Restoration Coordination EOP-008-2 – Loss of Control Center Functionality
January 1, 2020	CIP-003-7 – Cyber Security — Security Management Controls
	PRC-026-1 – Relay Performance During Stable Power Swings (Requirements 2–4)
July 1, 2020	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (50% compliance for Requirements 2–4, 6–11)
January 1, 2021	PRC-012-2 – Remedial Action Schemes
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements 6, 6.1–6.4)
January 1, 2022	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements 3,4,7)
July 1, 2022	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (100% compliance for Requirements 2–4, 6–11)

BOARD OF TRUSTEES AND FERC ACTION

NEW Opportunity to Suggest Canadian Candidates for NERC Board of Trustees

The Nominating Committee for the NERC Board of Trustees is providing an opportunity for stakeholders to suggest Canadian candidates to serve as an independent member of the NERC Board.

A summary memo from Fred Gorbet, Chair of the Nominating Committee, outlining the role of the Committee and the process for the nomination and election of independent members of the NERC Board is available. Included with the memo is a position specification prepared by the Committee and Odgers Berndtson. Odgers Berndtson has been retained by the Nominating Committee to assist in the search for and screening of candidates. Please submit all suggestions for candidates to Trevor Smith of Odgers Berndtson. **All suggestions for candidates must be received by June 30, 2018.**

NEW NERC Filings

On May 30, 2018, NERC filed with FERC an errata filing to the Implementation Plan for the revised definition of "Remedial Action Scheme" approved in FERC Order No. 818. This errata filing incorporates certain necessary implementation provisions from the Implementation Plan associated with Reliability Standard PRC-023-3 that were inadvertently omitted from the RAS Implementation Plan and previous errata to that Implementation Plan filed on September 15, 2017.

On May 31, 2018, NERC and WECC filed with FERC a joint petition for approval of proposed regional Reliability Standard BAL-004-WECC-3 – Automatic Time Error Correction.

NERC's 2018 filings to FERC are available here.

NEW FERC Issuances

On May 30, 2018, FERC issued a delegated letter order approving NERC and WECC's March joint petition for approval of proposed regional Reliability Standard FAC-501-WECC-2 – Transmission Maintenance.

On May 31, 2018, FERC issued a letter order accepting NERC's February 12, 2018 filing of proposed revisions to the SERC Reliability Corporation regional Reliability Standards Development Procedure (RSDP). FERC's 2018 issuances are available here.

UPCOMING EVENTS

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

Workshops and Conferences

- 2018 Power System Modeling Conference – June 20–21, 2018, New Albany, Ohio | Register for Reception | Register for Conference | Register for Hotel
- 2018 NERC Standards and Compliance Workshop – July 24–25, 2018, Columbus, Ohio | In-person Registration | Webinar Workshop Registration | Hotel Registration | Agenda
- GridSecCon 2018 – October 15–19, 2018, Las Vegas, Nevada | **Registration Information Coming Soon**

Webinars

- **NEW** 2018 Periodic Review Standing Review Team Standards Grading Webinar – Noon–1:30 p.m. Eastern, June 7, 2018 | Register
- Composite Resource Adequacy and Transmission Reliability Planning Webinar – 1:00–4:00 p.m. Eastern, June 12, 2018 | Register
- Inverter-Based Resource Webinar Series: Recommended Performance for Inverter-Based Resources Connected to the Bulk Power System – NERC Reliability Guideline – 2:00–4:00 p.m. Eastern, June 13, 2018 | Register

Standing Committee Meetings and Conference Calls

- Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee Meetings – June 5–6, 2018 | New Orleans, LA | Register for OC | Register for PC | Register for CIPC | Register for Hotel
- Standards Committee Meeting – 10:00 a.m.–3:00 p.m. Eastern, June 13, 2018 | Atlanta, GA | 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 – June 6–7, 2018, New Orleans, LA | Register
- Project 2016-02 – Modifications to CIP Standards Drafting Team Meeting – June 19–21, 2018, Atlanta, GA | Register

ABOUT THE STANDARDS, COMPLIANCE, AND ENFORCEMENT BULLETIN

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

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

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

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

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

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

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

Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
The observations of the Standards Efficiency Review (SER) Team related to each of the requirements above are listed below as a rationale for retirement. The SER Project divided into three teams; Real-time Operations (RT), Long-term Planning (LT), Operations Planning (OP) **BAL-005-1. R4, R6 (RT)** This reliability objective is duplicated in TOP-010-1(i) R2: *Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include:* *2.1. Criteria for evaluating the quality of Real-time data;* *2.2. Provisions to indicate the quality of Real-time data to the System Operator; and* *2.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions.* The BA is already required by TOP-010-1(i) R2 to have an Operating Process/Procedure to address quality of Real-time data (which would include Reporting ACE) which includes criteria to evaluate the data, provisions to indicate the quality of the data to the System Operator, and actions to address data quality issues with other entities. The same logic applies for R6 since TOP-010-1(i) R2 requires an Operating Process/Procedure to include criteria to evaluate the data, provisions to indicate the quality of the data to the System Operator, and actions to address data quality issues with other entities **COM-002-4 R2 (RT)** The related compliance activities are duplicative of the activities covered by the Systematic Approach to Training within the PER-005-2 Standard. **EOP-005-3 R8 (OP)** The requirement should be retired because the related compliance activities are duplicative of the activities covered by the Systematic Approach to Training within the PER Standards. The team also agrees that the requirement to provide at least two-hours of training is arbitrary. The training objective should be to assure thorough training such that System Operators are certified and competent to perform restoration activities. At minimum, as noted in the SER Operations Planning team comments on EOP-005-3 R8, we agree that EOP-006-3 R7 requirement can be retired and the

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

> *Each Reliability Coordinator shall monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

> *Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.*

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

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

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

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

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

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

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

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

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

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

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	yes

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

For Use by NERC Only

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

Version History

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

163 FERC ¶ 61,032
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM17-11-000; Order No. 843]

Revised Critical Infrastructure Protection Reliability Standard CIP-003-7 – Cyber Security – Security Management Controls

(Issued April 19, 2018)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) approves Critical Infrastructure Protection (CIP) Reliability Standard CIP-003-7 (Cyber Security – Security Management Controls), submitted by the North American Electric Reliability Corporation (NERC). Reliability Standard CIP-003-7 clarifies the obligations pertaining to electronic access control for low impact BES Cyber Systems; requires mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems; and requires responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems. In addition, the Commission directs NERC to develop modifications to the CIP Reliability Standards to mitigate the risk of malicious code that could result from third-party transient electronic devices.

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

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SUPPLEMENTARY INFORMATION:

163 FERC ¶ 61,032
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Revised Critical Infrastructure Protection Reliability Standard CIP-003-7 – Cyber Security – Security Management Controls	Docket No. RM17-11-000

ORDER NO. 843

FINAL RULE

(Issued April 19, 2018)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission approves Reliability Standard CIP-003-7 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. Reliability Standard CIP-003-7 addresses the Commission's directives from Order No. 822 and is an improvement over the current Commission-approved CIP Reliability Standards.[2] Specifically, Reliability Standard CIP-003-7 improves upon the existing Reliability Standards by: (1) clarifying the obligations pertaining to electronic access control for low impact BES Cyber Systems;[3]

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

[2] *Revised Critical Infrastructure Protection Reliability Standards*, Order No. 822, 154 FERC ¶ 61,037, *reh'g denied,* Order No. 822-A, 156 FERC ¶ 61,052 (2016).

[3] BES Cyber System is defined by NERC as "[o]ne or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a

(2) adopting mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems; and (3) requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems. We also approve NERC's proposed implementation plan and violation risk factor and violation severity level assignments. Finally, we approve NERC's proposed revised definitions for inclusion in the NERC Glossary.

2. In the NOPR, the Commission proposed to direct that NERC modify Reliability Standard CIP-003-7 to: (1) provide clear, objective criteria for electronic access controls for low impact BES Cyber Systems; and (2) address the need to mitigate the risk of malicious code that could result from third-party transient electronic devices.[4] The Commission adopts the NOPR proposal regarding third-party transient electronic devices but does not adopt the proposal regarding criteria for electronic access controls for low impact BES Cyber Systems.

functional entity." Glossary of Terms Used in NERC Reliability Standards (NERC Glossary). The acronym BES refers to the bulk electric system. Reliability Standard CIP-002-5.1a (Cyber Security System Categorization) provides a "tiered" approach to cybersecurity requirements, based on classifications of high, medium and low impact BES Cyber Systems.

[4] *Revised Critical Infrastructure Protection Reliability Standard CIP-003-7 – Cyber Security – Security Management Controls*, Notice of Proposed Rulemaking, 82 FR 49541 (Oct. 26, 2017), 161 FERC ¶ 61,047 (2017) (NOPR).

3. As discussed below, in view of the comments from NERC and others, we are persuaded that Reliability Standard CIP-003-7 provides a clear security objective that establishes compliance expectations. Accordingly, we do not adopt the proposed directive relating to electronic access controls for low impact BES Cyber Systems. Instead, as suggested in the comments, we direct NERC to conduct a study to assess the implementation of Reliability Standard CIP-003-7 to determine whether the electronic access controls adopted by responsible entities provide adequate security. NERC must submit the directed study within eighteen months of the effective date of Reliability Standard CIP-003-7.

4. With regard to the second issue discussed in the NOPR, we remain concerned that the proposed Reliability Standard lacks a clear requirement to mitigate the risk of malicious code that could result from third-party transient electronic devices. Accordingly, we direct NERC to develop a modification to the Reliability Standard to provide the needed clarity. Such modification will better ensure that registered entities clearly understand their mitigation obligations and, thus, improve individual entity mitigation plans and collectively improve the cybersecurity posture of the electric grid.

I. Background

A. Section 215 and Mandatory Reliability Standards

5. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Reliability Standards may be enforced by the ERO,

subject to Commission oversight, or by the Commission independently.[5] Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[6] and subsequently certified NERC.[7]

B. Order No. 822

6. The Commission approved the "Version 1" CIP Reliability Standards in January 2008, and subsequently acted on revised versions of the CIP Reliability Standards.[8] On January 21, 2016, in Order No. 822, the Commission approved seven CIP Reliability Standards: CIP-003-6 (Security Management Controls), CIP-004-6 (Personnel and Training), CIP-006-6 (Physical Security of BES Cyber Systems), CIP-007-6 (Systems Security Management), CIP-009-6 (Recovery Plans for BES Cyber Systems), CIP-010-2 (Configuration Change Management and Vulnerability Assessments), and CIP-011-2 (Information Protection). The Commission determined that the Reliability Standards

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

[6] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

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

[8] *Mandatory Reliability Standards for Critical Infrastructure Protection*, Order No. 706, 122 FERC ¶ 61,040, *order on reh'g*, Order No. 706-A, 123 FERC ¶ 61,174 (2008), *order on clarification*, Order No. 706-B, 126 FERC ¶ 61,229 (2009), *order on clarification*, Order No. 706-C, 127 FERC ¶ 61,273 (2009); *Version 5 Critical Infrastructure Protection Reliability Standards*, Order No. 791, 145 FERC ¶ 61,160 (2013), *order on clarification and reh'g*, Order No. 791-A, 146 FERC ¶ 61,188 (2014).

under consideration at that time were an improvement over the prior iteration of the CIP Reliability Standards and addressed the directives in Order No. 791 by, among other things, addressing in an equally effective and efficient manner the need for a NERC Glossary definition for the term "communication networks" and providing controls to address the risks posed by transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at high and medium impact BES Cyber Systems.[9]

7. In addition, in Order No. 822, pursuant to section 215(d)(5) of the FPA, the Commission directed NERC, *inter alia*, to: (1) develop modifications to the Low Impact External Routable Connectivity (LERC) definition to eliminate ambiguity surrounding the term "direct" as it is used in the LERC definition; and (2) develop modifications to the CIP Reliability Standards to provide mandatory protection for transient electronic devices used at low impact BES Cyber Systems.[10]

C. NERC Petition

8. On March 3, 2017, NERC submitted a petition seeking approval of Reliability Standard CIP-003-7 and the associated violation risk factors and violation severity levels, implementation plan and effective date. NERC states that Reliability Standard CIP-003-7 satisfies the criteria set forth in Order No. 672 that the Commission applies when

[9] Order No. 822, 154 FERC ¶ 61,037 at P 17.

[10] *Id.* P 18.

reviewing a proposed Reliability Standard.[11] NERC also sought approval of revisions to NERC Glossary definitions for the terms Removable Media and Transient Cyber Asset, as well as the retirement of the NERC Glossary definitions of LERC and Low Impact BES Cyber System Access Point (LEAP). In addition, NERC proposed the retirement of Commission-approved Reliability Standard CIP-003-6.[12]

9. NERC states that Reliability Standard CIP-003-7 improves upon the existing protections that apply to low impact BES Cyber Systems. NERC avers that the proposed modifications address the Commission's directives from Order No. 822 by: (1) clarifying electronic access control requirements applicable to low impact BES Cyber Systems; and (2) adding requirements for the protection of transient electronic devices used for low impact BES Cyber Systems. In addition, while not required by Order No. 822, NERC proposes a CIP Exceptional Circumstances policy for low impact BES Cyber Systems.

10. In response to the Commission's directive to develop modifications to eliminate ambiguity surrounding the term "direct" as it is used in the LERC definition, NERC proposes to: (1) retire the terms LERC and LEAP from the NERC Glossary; and (2) modify Section 3 of Attachment 1 to Reliability Standard CIP-003-7 "to more clearly

[11] *See* NERC Petition at 2 (citing Order No. 672, FERC Stats. & Regs. ¶ 31,204 at PP 262, 321-337); *id.*, Exhibit D (Order No. 672 Criteria).

[12] Reliability Standard CIP-003-7 is not attached to this Final Rule. The Reliability Standard is available on the Commission's eLibrary document retrieval system in Docket No. RM17-11-000 and is posted on the NERC website, http://www.nerc.com.

delineate the circumstances under which Responsible Entities must establish access controls for low impact BES Cyber Systems."[13] NERC states that the proposed revisions are designed to simplify the electronic access control requirements associated with low impact BES Cyber Systems to avoid ambiguities associated with the term "direct." NERC explains that it recognized the "added layer of unnecessary complexity" introduced by distinguishing between "direct" and "indirect" access within the LERC definition and asserts that the proposed revisions will "help ensure that Responsible Entities implement the required security controls effectively."[14]

11. With regard to the Commission's directive that NERC develop modifications to the CIP Reliability Standards to provide mandatory protection for transient electronic devices used at low impact BES Cyber Systems, NERC proposes to add a new section to Attachment 1 of Reliability Standard CIP-003-7 that requires responsible entities to include controls in their cyber security plans to mitigate the risk of the introduction of malicious code to low impact BES Cyber Systems that could result from the use of "Transient Cyber Assets or Removable Media." Specifically, proposed Section 5 of Attachment 1 lists controls to be applied to Transient Cyber Assets and Removable Media that NERC contends "will provide enhanced protections against the propagation of malware from transient devices."[15]

[13] NERC Petition at 16.

[14] *Id.* at 16.

[15] *Id.* at 26-27.

12. NERC also proposes a modification that was not directed by the Commission in Order No. 822. Namely, NERC proposes revisions in Requirement R1 of Reliability Standard CIP-003-7 to require responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems.[16] NERC states that a number of requirements in the existing CIP Reliability Standards specify that responsible entities do not have to implement or continue implementing these requirements to avoid hindering the entities' ability to timely and effectively respond to the CIP Exceptional Circumstance. NERC proposes to add a requirement for responsible entities to have a CIP Exceptional Circumstances policy that applies to low impact BES Cyber Systems since the proposed requirements relating to transient electronic devices used at low impact BES Cyber Systems include an exception for CIP Exceptional Circumstances.[17]

13. NERC requests that Reliability Standard CIP-003-7 and the revised definitions of Transient Cyber Asset and Removable Media become effective the first day of the first calendar quarter that is eighteen months after the effective date of the Commission's order approving the Reliability Standard.

[16] A CIP Exceptional Circumstance is defined in the NERC Glossary as a situation that involves or threatens to involve one or more of the following, or similar, conditions that impact safety or bulk electric system reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a Cyber Security Incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability.

[17] NERC Petition at 31-32.

D. Notice of Proposed Rulemaking

14. On October 19, 2017, the Commission issued a NOPR that proposed to approve Reliability Standard CIP-003-7. The NOPR proposed to determine that Reliability Standard CIP-003-7 is just, reasonable, not unduly discriminatory or preferential, and in the public interest and addresses the directives in Order No. 822 by: (1) clarifying the obligations pertaining to electronic access control for low impact BES Cyber Systems; and (2) adopting mandatory security controls for transient electronic devices used at low impact BES Cyber Systems. In addition, the NOPR observed that, by requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances for low impact BES Cyber Systems, Reliability Standard CIP-003-7 would align the treatment of low impact BES Cyber Systems with that of high and medium impact BES Cyber Systems, which currently include a requirement for declaring and responding to CIP Exceptional Circumstances. Therefore, the Commission proposed to approve Reliability Standard CIP-003-7 because the proposed modifications improve the base-line cybersecurity posture of responsible entities compared to the current Commission-approved CIP Reliability Standards.

15. In addition, the Commission proposed to direct that NERC develop modifications to Reliability Standard CIP-003-7 to addressed two issues: (1) provide clear, objective criteria for electronic access controls for low impact BES Cyber Systems; and (2) address the need to mitigate the risk of malicious code that could result from third-party transient electronic devices. The Commission explained that modifications directed at these two

concerns will address potential gaps and improve the cyber security posture of responsible entities that must comply with the CIP Reliability Standards.

16. The Commission received comments in response to the NOPR from Jonathan Appelbaum (Appelbaum), Electric Consumers Resource Council (ELCON), North American Electric Reliability Corporation (NERC), Transmission Access Policy Study Group (TAPS), and Trade Associations.[18] We address below the issues raised in the NOPR and comments.

II. Discussion

17. Pursuant to section 215(d)(2) of the FPA, we approve Reliability Standard CIP-003-7 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. Reliability Standard CIP-003-7 addresses the directives in Order No. 822 and is an improvement over the currently-effective, Commission-approved CIP Reliability Standards. Specifically, Reliability Standard CIP-003-7 improves upon the existing CIP Reliability Standards by: (1) clarifying the obligations pertaining to electronic access control for low impact BES Cyber Systems; (2) adopting mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems; and (3) requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems. We also approve NERC's proposed implementation plan and violation risk factor and

[18] Trade Associations represent American Public Power Association, Edison Electric Institute, and National Rural Electric Cooperative Association.

violation severity level assignments. Finally, we approve NERC's proposed revised definitions for inclusion in the NERC Glossary.

18. In addition, as discussed below, pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop modifications to the CIP Reliability Standards to mitigate the risk of malicious code that could result from third-party transient electronic devices. However, for the reasons discussed below, we determine not to adopt the NOPR proposal to direct NERC to develop criteria for electronic access controls for low impact BES Cyber Systems at this time.

19. Below, we discuss the following matters: (A) criteria for electronic access controls for low impact BES Cyber Systems; (B) mitigation of the risk of malicious code associated with third-party transient electronic devices; and (C) implementation plan and effective date.

A. Criteria for Electronic Access Controls for Low Impact BES Cyber Systems

1. NOPR

20. In the NOPR, the Commission proposed to direct NERC to develop modifications to Section 3 of Attachment 1 to Reliability Standard CIP-003-7 to provide clear, objective criteria for electronic access controls for low impact BES Cyber Systems.[19] Specifically, the proposed directive addressed the concern that Reliability Standard CIP-003-7 may not provide adequate electronic access controls for low impact BES Cyber Systems because Reliability Standard CIP-003-7 does not provide clear, objective criteria or measures to

[19] NOPR, 161 FERC ¶ 61,047 at P 32.

assess compliance by independently confirming that the access control strategy adopted by a responsible entity would reasonably meet the security objective of permitting only "necessary inbound and outbound electronic access" to its low impact BES Cyber Systems.[20] The Commission stated that, in order to ensure an objective and consistently-applied requirement, the electronic access control plan required in Attachment 1 should require the responsible entity to articulate its access control strategy for a particular set of low impact BES Cyber Systems and provide a technical rationale rooted in security principles explaining how that strategy will reasonably restrict electronic access. In addition, the Commission stated that Attachment 1 should outline basic security principles in order to provide clear, objective criteria or measures to assist in assessing compliance.[21]

21. The Commission observed that without clear, objective criteria or measures, auditors will not necessarily have adequate information to assess the reasonableness of the responsible entity's decision with respect to how the responsible entity identified necessary communications or restricted electronic access to specific low impact BES Cyber Systems. The Commission posited that absent such information, it is possible that an auditor could assess a violation where an entity adequately protected its low impact

[20] *Id.* P 28.

[21] *Id.* P 29.

BES Cyber Systems or fail to recognize a situation where additional protections are necessary to meet the security objective of the Reliability Standard.[22]

2. Comments

22. NERC acknowledges the NOPR concerns but comments that a directive "may not be necessary."[23] Specifically, NERC asserts that "Responsible Entities must provide auditors sufficient information to allow the auditors to properly assess compliance with section 3.1" of Reliability Standard CIP-003-7.[24] NERC contends that Section 3.1 "articulates a clear security objective: permit only necessary inbound and outbound access to low impact BES Cyber Systems."[25] NERC explains that Section 3.1 is not prescriptive due to the wide array of low impact BES Cyber Systems and their lower risk to bulk electric system reliability, but, while Section 3.1 grants responsible entities flexibility, "a Responsible Entity must demonstrate that its electronic access permissions and controls are consistent with the security objective."[26] Specifically, NERC maintains that a responsible entity "must document the necessity of its inbound and outbound electronic access permissions and provide justification of the need for such access."[27]

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[22] *Id.*

[23] NERC Comments at 3.

[24] *Id.* (citing NERC Petition at 21-24).

[25] *Id.*

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

[27] *Id.* at 4 (citing NERC Petition at 22).

NERC states further that "[i]f a Responsible Entity fails to articulate a reasonable business or operational need for the electronic access permission, the ERO Enterprise would find that the Responsible Entity did not comply with Section 3.1."[28] NERC continues that "[c]onsistent with the intent of the Commission's proposed directive, the Responsible Entity would have to articulate its access control strategy for the low impact BES Cyber System and provide a technical rationale rooted in security principles, explaining how that strategy will reasonably restrict electronic access."[29] NERC states that if a responsible entity "fails to demonstrate that its chosen electronic access controls are properly designed and implemented to meet the security objective, the ERO Enterprise would find that the Responsible Entity did not comply with Section 3.1" of Reliability Standard CIP-003-7.[30]

23. NERC concludes that while the Commission's proposed directive may not be necessary and could potentially be an inefficient use of NERC and industry resources, "[a]rticulating objective criteria for electronic access controls for low impact BES Cyber Systems may improve clarity and auditability, and help ensure that entities implement effective electronic access controls."[31]

24. Trade Associations, TAPS and ELCON do not support the proposed directive, claiming that the proposal would impose additional burdens on registered entities without

[28] *Id.*

[29] *Id.*

[30] *Id.*

[31] *Id.* at 5.

a corresponding reliability benefit. Trade Associations and TAPS contend that Section 3 of Attachment 1 to Reliability Standard CIP-003-7 gives responsible entities needed flexibility to develop and implement effective electronic access controls for low impact BES Cyber Systems. TAPS adds that Reliability Standard CIP-003-7 reflects what NERC, through the standard development process, "determined was a technically appropriate tailoring of electronic access controls requirements to low impact BES cyber systems."[32] Trade Associations recommend, as an alternative to the proposed directive, that the Commission approve the proposed Reliability Standard without modification and monitor its concerns, for example, by directing NERC to conduct a study to assess the implementation by responsible entities of Reliability StandardCIP-003-7 electronic access controls to determine whether there are in fact inadequate controls. According to Trade Associations, a fact-driven assessment would help to inform and demonstrate a reliability and security need for future Commission actions related to the CIP Reliability Standards.[33]

25. Further, Trade Associations assert that a risk-based approach is essential to allow responsible entities to focus their resources on assets that have a higher impact on bulk electric system reliability. ELCON adds that while it "appreciates the value establishing more tangible criteria for adequate Low-Impact BES Cyber System controls, … the

[32] TAPS Comments at 7 (*citing* 16 U.S.C. 824o(d)).

[33] Trade Associations Comments at 9.

additional requirements that the Commission proposes would do nothing to harden a Low-Impact facility against the rapid evolution in cyber warfare."[34]

26. Appelbaum supports the proposed directive regarding Section 3 of Attachment 1 to Reliability Standard CIP-003-7. Appelbaum notes that Reliability Standard CIP-003-7 "leaves the choice of controls to the [responsible entity] and leaves an Auditor with no requirement basis to perform an audit."[35] Appelbaum states that under "NERC's proposal that each entity establishes their own security plan and only needs to demonstrate compliance and adherence to its plan then … the implementation of security controls will be implemented to various levels of security and differentiated … across the NERC Regions."[36] Appelbaum states further that Reliability Standard CIP-003-7 "will result in different auditor conclusions for similarly situated entities implementing similar protections."[37] Appelbaum concludes that "[c]lear requirements are needed to establish a common understanding of the necessary security to be achieved."[38]

3. Commission Determination

27. We do not to adopt the proposed directive, but rather adopt the Trade Associations' recommendation for a study and report to be filed with the Commission. We are satisfied with the explanation of NERC and other commenters that Section 3 of

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[34] ELCON Comments at 4.

[35] Applebaum Comments at 5.

[36] *Id.* at 6.

[37] *Id.* at 7.

[38] *Id.*

Attachment 1 to Reliability Standard CIP-003-7 provides a clear security objective that establishes compliance expectations. Specifically, we are persuaded by commenters that Section 3 of Attachment 1 requires responsible entities to adopt security controls to permit only necessary inbound and outbound electronic access to Cyber Assets connected using a routable protocol to low impact BES Cyber Systems.

28. The concern raised in the NOPR focused on the lack of clear, objective criteria or measures to assess compliance with Reliability Standard CIP-003-7. As noted above, however, NERC states in its comments that responsible entities will be required to demonstrate that electronic access permissions and controls associated with low impact BES Cyber Systems are consistent with the stated security objective. NERC also clarifies that responsible entities will be required to "document the [business or operational] necessity of its inbound and outbound electronic access permissions and provide justification of the need for such access."[39] Given NERC's statements, we believe that there will be adequate measures to assess compliance with Reliability Standard CIP-003-7. We expect responsible entities to be able to provide a technically sound explanation as to how their electronic access controls meet the security objective.

29. In response to Appelbaum's comment that auditors will not have a common understanding on which to judge compliance across the ERO enterprise, in view of NERC's comments, we believe that NERC and the Regional Entities will have the ability

[39] NERC Comments at 4.

to assess the effectiveness of a responsible entity's electronic access control plan as well as a responsible entity's adherence to its electronic access control plan.

30. Moreover, to ensure that the security controls are implemented and that Section 3 accomplishes its intended purpose, we adopt Trade Associations' proposal and direct NERC to conduct a study to assess the implementation of Reliability Standard CIP-003-7.[40] The study should address what electronic access controls entities choose to implement and under what circumstances, and whether the electronic access controls adopted by responsible entities provide adequate security, as well as other relevant information found by NERC as a result of the study. NERC must file the study within eighteen months of the effective date of Reliability Standard CIP-003-7. We may revisit the need for modifications to Section 3 of Attachment 1 to Reliability Standard CIP-003-7 if warranted by the study determination, or the results of audits or other compliance procedures.

B. Mitigation of the Risk of Malicious Code Associated with Third-Party Transient Electronic Devices

1. NOPR

31. In the NOPR, the Commission proposed to direct NERC to develop modifications to proposed Section 5 of Attachment 1 to Reliability Standard CIP-003-7 to mitigate the risk of malicious code that could result from third-party transient electronic devices.[41] Specifically, the Commission raised a concern that Reliability Standard CIP-003-7 does

[40] Trade Associations Comments at 9.

[41] *Id.* P 41.

not explicitly require mitigation of the introduction of malicious code from third-party managed transient electronic devices, even if the responsible entity determines that the third-party's policies and procedures are inadequate. The Commission noted NERC's statement in its petition that a responsible entity's failure to mitigate this risk "may not constitute compliance."[42] The Commission stated that NERC's explanation suggests that, with regard to low impact BES Cyber Systems, the requirement lacks an obligation for a responsible entity to correct any deficiencies that are discovered during a review of third-party transient electronic device management practices.

32. The Commission expressed concern that Reliability Standard CIP-003-7 may contain a reliability gap where a responsible entity contracts with a third-party but fails to mitigate potential deficiencies discovered in the third-party's malicious code detection and prevention practices prior to a transient electronic device being connected to a low impact BES Cyber System. The Commission explained that the reliability gap would result from the fact that Reliability Standard CIP-003-7 does not contain: (1) a requirement for the responsible entity to mitigate any malicious code found during the third-party review(s); or (2) a requirement that the responsible entity take reasonable steps to mitigate the risks of third party malicious code on its systems, if an arrangement cannot be made for the third-party to do so. The Commission observed that without such

[42] *Id.* P 39 (*citing* NERC Petition at 30).

obligations responsible entities could, without compliance consequences, simply accept the risk of deficient third-party transient electronic device management practices.[43]

33. Therefore, pursuant to section 215(d)(5) of the FPA, the Commission proposed to direct NERC to modify Reliability Standard CIP-003-7 to require responsible entities to implement controls to address the need to mitigate the risk of malicious code that could result from third-party transient electronic devices.

2. Comments

34. NERC states that it "agrees with the Commission that, should a Responsible Entity find that a third party's processes and practices for protecting its transient electronic devices inadequate, the Responsible Entity must be required to take mitigating action prior to connecting third-party transient electronic devices to a low impact BES Cyber System."[44] According to NERC, "failure to take mitigating action in this circumstance[] could result in a finding of noncompliance with Section 5 of Attachment 1."[45] NERC, therefore, asserts that "the proposed directive may not be necessary and may be an inefficient use of NERC and industry resources."[46] NERC observes, however, that

[43] *Id.* P 40 (*citing* Order No. 706, 122 FERC ¶ 61,040 at P 150 (rejecting the concept of acceptance of risk in the CIP Reliability Standards)).

[44] NERC Comments at 6 (citing NERC Petition at 29).

[45] *Id.*

[46] *Id.*

"[m]odifying proposed Section 5 to explicitly include a mitigation requirement for third-part[y] devices may remove any doubt about compliance expectations."[47]

35. Trade Associations and ELCON do not support the proposed directive. Trade Associations contend that "[a]lthough Section 5.2 [of Attachment 1 to CIP-003-7] does not explicitly require the responsible entity to mitigate the introduction of malicious code, risk mitigation is an explicit obligation under Section 5."[48] Trade Associations state that if a responsible entity's plan does not "achieve the objective of mitigating the risk of the introduction of malicious code to low impact BES Cyber Systems through the use of Transient Cyber Assets … then the plan will not comply with Section 5."[49] Trade Associations maintains that the "intent of the requirement is made clear in the Supplemental Material for Section 5 and 5.2, which both require the responsible entities to document how they will mitigate the introduction of malicious code."[50] Trade Associations note in a footnote that:

> Although the Supplemental Material does not create binding obligations on responsible entities, the text of the Supplemental Material in the Proposed Standard further clarifies and reinforces that the binding requirements found in CIP-003-7, Attachment 1, Section 5 include the obligation to take additional steps if a third-party's practices do not meet the security objective.[51]

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[47] *Id.*

[48] Trade Associations Comments at 10.

[49] *Id.* at 11.

[50] *Id.*

[51] *Id.*

Trade Associations conclude that the Commission should approve Reliability Standard CIP-003-7 without modification.

36. ELCON states that "the requirement for a Low-Impact BES Cyber System owner or operator to actively mitigate deficiencies in third party's anti-virus security programs does exist in [Section 5 of Attachment 1 to Reliability Standard CIP-003-7]."[52] ELCON states that the opening paragraph of Section 5, which requires responsible entities to implement one or more plans to "achieve the objective of mitigating the risk of the introduction of malicious code to low impact BES Cyber Systems through the use of Transient Cyber Assets or Removable Media," establishes an obligation to mitigate any identified deficiencies. ELCON contends that the objective of mitigating the risk "cannot be reached if the Responsible Entity allows a third party to connect an insufficiently evaluated [Transient Cyber Asset] to a Low-Impact BES Cyber System."[53] ELCON argues that the "positioning of the requirement in the opening paragraph of Section 5 assures that mitigating actions must be taken to address deficiencies detected" with responsible entity-owned Transient Cyber Assets, vendor-owned Transient Cyber Assets, and Removable Media.[54]

[52] ELCON Comments at 4 (emphasis in original).

[53] *Id.* at 4-5.

[54] *Id.* at 5.

3. Commission Determination

37. We adopt the NOPR proposal and, pursuant to section 215(d)(5) of the FPA, direct that NERC develop modifications to Reliability Standard CIP-003-7 to address our concern and ensure that responsible entities implement controls to mitigate the risk of malicious code that could result from third-party transient electronic devices. NERC could satisfactorily address the identified concern, for example, by modifying Section 5 of Attachment 1 to CIP-003-7 to clarify that responsible entities must implement controls to mitigate the risk of malicious code that could result from the use of third-party transient electronic devices.

38. The directed modification will improve the security posture of responsible entities by clarifying compliance expectations. While commenters claim that the provision is sufficiently clear and ask the Commission not to adopt the proposal, all commenters agree that there is not an explicit requirement to mitigate the threat of malicious code that could result from third-party transient electronic devices. While Trade Associations state that Section 5.2 of Attachment 1 does not explicitly require the mitigation of malicious code, Trade Associations and ELCON suggest that Section 5 generally requires risk mitigation. While commenters agree that, at least implicitly, the mitigation of malicious code is an obligation, the lack of a clear requirement could lead to confusion in both the development of a compliance plan and in the implementation of a compliance plan. In addition, although NERC contends that the proposed directive may not be necessary, NERC agrees that modifying Reliability Standard CIP-003-7 to address the mitigation of malicious code explicitly could clarify compliance obligations.

39. Therefore, pursuant to FPA section 215(d)(5), we direct NERC to develop and submit modifications to Reliability Standard CIP-003-7 to include an explicit requirement that responsible entities implement controls to mitigate the risk of malicious code that could result from third-party transient electronic devices.

C. Implementation Plan and Effective Date

NERC Petition

40. In its petition, NERC requests an effective date for Reliability Standard CIP-003-7 and the revised definitions of Transient Cyber Asset and Removable Media on the first day of the first calendar quarter that is eighteen months after the effective date of the Commission's order approving the Reliability Standard. NERC explains that the implementation plan does not alter the previously-approved compliance dates for Reliability Standard CIP-003-6 other than the compliance date for Reliability Standard CIP-003-6, Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003-7. NERC also proposes that the retirement of Reliability Standard CIP-003-6 and the associated definitions become effective on the effective date of Reliability Standard CIP-003-7.[55]

41. The NOPR proposed to approve NERC's implementation plan and effective date for Reliability Standard CIP-003-7. The Commission did not receive any comments regarding this aspect of the NOPR. Accordingly, we approve NERC's proposed implementation plan and effective date.

[55] *Id.*, Exhibit C (Implementation Plan).

III. Information Collection Statement

42. The FERC-725B information collection requirements contained in this Final Rule are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[56] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[57] 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.

43. The Commission bases its paperwork burden estimates on the changes in paperwork burden presented by the proposed revision to CIP Reliability Standard CIP-003-7 as compared to the current Commission-approved Reliability Standard CIP-003-6. The Commission has already addressed the burden of implementing Reliability Standard CIP-003-6.[58] As discussed above, the immediate rulemaking addresses three areas of modification to the CIP Reliability Standards: (1) clarifying the

[56] 44 U.S.C. 3507(d) (2012).

[57] 5 CFR 1320.11 (2017).

[58] *See* Order No. 822, 154 FERC ¶ 61,037 at PP 84-88.

obligations pertaining to electronic access control for low impact BES Cyber Systems; (2) adopting mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems; and (3) requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems.

44. The NERC Compliance Registry, as of September 2017, identifies approximately 1,320 U.S. entities that are subject to mandatory compliance with Reliability Standards. Of this total, we estimate that 1,100 entities will face an increased paperwork burden under Reliability Standard CIP 003-7, estimating that a majority of these entities will have one or more low impact BES Cyber Systems. Based on these assumptions, we estimate the following reporting burden:

RM17-11-000 Final Rule (Mandatory Reliability Standards for Critical Infrastructure Protection Reliability Standards)						
	Number of Respondents (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response[59] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**

[59] The loaded hourly wage figure (includes benefits) is based on the average of three occupational categories for 2016 found on the Bureau of Labor Statistics website (http://www.bls.gov/oes/current/naics2_22.htm):

Legal (Occupation Code: 23-0000): $143.68

Electrical Engineer (Occupation Code: 17-2071): $68.12

Office and Administrative Support (Occupation Code: 43-0000): $40.89

Create low impact TCA assets plan (one-time)[60]	1,100	1	1,100	20 hrs.; $1,680	6,875 hrs.; $1,848,000	$1,680
Updates and reviews of low impact TCA assets (ongoing)[61]	1,100	300[62]	330,000	1.5 hrs.[63]; $126	495,000 hrs.; $41,580,000	$37,800
Update/modify documentation to remove LERC and LEAP (one-time)[60]	1,100	1	1,100	20 hrs.; $1,680	6,875 hrs.; $1,848,000	$1,680
Update paperwork for access control implementation in Section 2[64] and Section 3[65] (ongoing)[61]	1,100	1	1,100	20 hrs.; $1,680	6,875 hrs.; $1,848,000	$1,680
TOTAL (one-time)[60]			**2,200**		**13,750 hrs.; $3,696,000**	
TOTAL (ongoing)[61]			**331,100**		**501,875 hrs.; $43,428,000**	

45. The following shows the annual cost burden for each group, based on the burden hours in the table above:

($143.68 + $68.12 + $40.89) ÷ 3 = $84.23. The figure is rounded to $84.00 for use in calculating wage figures in this NOPR.

[60] This one-time burden applies in Year One only.

[61] This ongoing burden applies in Year 2 and beyond.

[62] We estimate that each entity will perform 25 updates per month. 25 updates *12 months = 300 updates (i.e. responses) per year.

[63] The 1.5 hours of burden per response is comprised of three sub-categories:

Updates to managed low TCA assets: 15 minutes (0.25 hours) per response

Updates to unmanaged low TCA assets: 60 minutes (1 hour) per response

Reviews of low TCA applicable controls: 15 minutes (0.25 hours) per response.

[64] Physical Security Controls.

[65] Electronic Access Controls.

- Year 1: $3,696,000
- Years 2 and 3: $43,428,000
- The paperwork burden estimate includes costs associated with the initial development of a policy to address requirements relating to: (1) clarifying the obligations pertaining to electronic access control for low impact BES Cyber Systems; (2) adopting mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems; and (3) requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems. Further, the estimate reflects the assumption that costs incurred in year 1 will pertain to policy development, while costs in years 2 and 3 will reflect the burden associated with maintaining logs and other records to demonstrate ongoing compliance.

46. Title: Mandatory Reliability Standards, Revised Critical Infrastructure Protection Reliability Standards

Action: Revision to FERC-725B information collection.

OMB Control No.: 1902-0248.

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

Frequency of Responses: On Occasion.

Necessity of the Information: This Final Rule approves the requested modifications to Reliability Standards pertaining to critical infrastructure protection. As discussed above,

the Commission approves NERC's revised CIP Reliability Standard CIP-003-7 pursuant to section 215(d)(2) of the FPA because it improves upon the currently-effective suite of cyber security CIP Reliability Standards.

Internal Review: The Commission has reviewed the Reliability Standard and made a determination that its action is necessary to implement section 215 of the FPA.

47. 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].

48. 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, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, 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 RM17-11-000 and OMB Control Number 1902-0248.

IV. Regulatory Flexibility Act Analysis

49. The Regulatory Flexibility Act of 1980 (RFA) generally requires a description and analysis of Final Rules that will have significant economic impact on a substantial

number of small entities.[66] The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[67] 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).[68] Reliability Standard CIP-003-7 is expected to impose an additional burden on 1,100 entities[69] (reliability coordinators, generator operators, generator owners, interchange coordinators or authorities, transmission operators, balancing authorities, transmission owners, and certain distribution providers).

50. Of the 1,100 affected entities discussed above, we estimate that approximately 857 or 78 percent[70] of the affected entities are small. As discussed above, Reliability Standard CIP-003-7 enhances reliability by providing criteria against which NERC and the Commission can evaluate the sufficiency of an entity's electronic access controls for low impact BES Cyber systems, as well as improved security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems). We estimate that each of the

[66] 5 U.S.C. 601-12 (2012).

[67] 13 CFR 121.101 (2017).

[68] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77343 (Dec. 23, 2013).

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

[70] 77.95 percent.

857 small entities to whom the modifications to Reliability Standard CIP-003-7 applies will incur one-time costs of approximately $3,360 per entity to implement this standard, as well as the ongoing paperwork burden reflected in the Information Collection Statement (approximately $39,480per year per entity). We do not consider the estimated costs for these 857 small entities to be a significant economic impact.

51. Based on the above analysis, we certify that the approved Reliability Standard will not have a significant economic impact on a substantial number of small entities.

V. Environmental Analysis

52. 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.[71] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[72] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

VI. Document Availability

53. 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

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

[72] 18 CFR 380.4(a)(2)(ii) (2017).

(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.

54. 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.

VII. Effective Date and Congressional Notification

55. The Final Rule is effective [**INSERT DATE 60 days from publication in FEDERAL REGISTER**]. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory

Enforcement Fairness Act of 1996. This Final Rule is being submitted to the Senate, House, and Government Accountability Office.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	Canadian-specific Revision to proposed standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events)		
Date Submitted:	February 27, 2018		
SAR Requester			
Name:	Helen Lainis (IESO) and Payam Farahbakhsh (Hydro One)		
Organization:	Canadian Electricity Association ("CEA") Members from Ontario (IESO and Hydro One), with the support of additional CEA Members including Manitoba Hydro, Hydro Québec and SaskPower.		
Telephone:	Helen: 905-855-4106 Payam: 416- 345 - 5484	Email:	Helen: helen.lainis@ieso.ca Payam: Payam.Farahbakhsh@HydroOne.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☒ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The need for this SAR is to enable the option for Canadian Registered Entities to leverage operating experience, observed GMD effects and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events specific to their unique topology. Registered Entities from Ontario, Québec, Manitoba and Saskatchewan have indicated support for a revision to be included in TPL-007-2 as an option for Canadian Registered Entities to pursue. At a minimum, Registered Entities in Ontario (Hydro One and IESO) have indicated that this proposed			

Requested information
revision would be used to define and implement an alternative Benchmark GMD Event and/or Supplemental GMD Event that appropriately reflects their specific geographical and geological characteristics.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The goal is to enable Canadian Registered Entities to define and implement alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflects the specific geographical and geological characteristics of the Canadian provinces, including those located on the Canadian Shield, a vast area of igneous rock exhibiting low electrical conductivity, through leveraging ongoing research efforts, operating experience, and observed GMD effects: • Registered Canadian entities from Canadian provinces (most prominently Manitoba, Ontario and Québec) located on the Canadian Shield, are currently working to develop a Benchmark GMD Event and/or Supplemental GMD Event that takes into account their unique topology. • These Canadian Registered Entities have been researching the impact of GMD on their power systems for several years now, and have been collaborating with Natural Resources Canada to collect and analyze Canadian magnetometer data for their respective provinces.
Project Scope (Define the parameters of the proposed project):
Reliability Standard TPL-007-2 should be revised to allow Canadian jurisdictions to define and implement alternative Benchmark GMD Events and/or Supplemental GMD Events that are different from the ones defined in TPL-007-2 appropriate for a continent wide standard. The Benchmark GMD Event and/or Supplemental GMD Event described in TPL-007-2 should be options to pursue for Canadian Registered Entities for performing GMD Vulnerability Assessments. Implementation of Benchmark GMD Events and/or Supplemental GMD Events by Canadian Registered Entities should be subject to approval by applicable Canadian governmental authority or their agencies.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
NERC has spent a substantial amount of time and effort working with experts across the industry to develop scientifically sound Benchmark GMD Events defined in TPL-007-2 appropriate for a continent wide standard.

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

Requested information
The research and development in this field continues to evolve, and more remains to be learned, new assessment tools need to be developed and assessment models need to be verified. In Canada, there is on-going work being done on this subject. We request that TPL-007-2 provide the flexibility for Canadian jurisdictions to leverage their expertise and to build on their research and on GMD impact assessment methodologies to define alternative Benchmark GMD Events and/or Supplemental GMD Events targeted to their unique topology. The Canadian Shield is a sprawling rock formation that stretches across nearly all of Québec, much of Ontario and Manitoba, the northern portion of Saskatchewan and the northeast corner of Alberta. This geological formation blocks current from being dissipated into the Earth, making these Canadian provinces more susceptible to solar storms. As such, Registered Entities from several Canadian shield provinces have been researching the impact of GMD on the reliable operation of their BES for years. For example, Hydro One Networks Inc., has been conducting this work in Ontario, Manitoba Hydro has been conducting this work in Manitoba and Hydro Québec has been conducted this work in Québec. A list of several technical publications could be provided upon request of the SDT to demonstrate the depth of Hydro One's, Manitoba Hydro's, Hydro Québec's and other jurisdictions' technical research and expertise in modeling and analyzing GMD impacts. These references also describe significant development efforts on tools and operating processes to support planned transmission system performance during GMD events. Natural Resources Canada has published their calculations of extreme value statistics for a 1-50 and 1-100 year geomagnetic storm based on data from 13 Natural Resources Canada geomagnetic observatories, and Natural Resources Canada and Registered Entities from Canadian shield provinces have been collaborating to collect and analyze Canadian magnetometer data for their respective provinces.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost implications of addressing a Benchmark GMD Event and/or Supplemental GMD Event is expected to be more significant for the Canadian shield provinces than for those registered entities in the lower 48 state portion of the United States. Furthermore, any capital investment must be approved by the applicable provincial regulatory authority. Consequently, it is essential that the requirements of the standard appropriately reflect conditions that exist in affected Canadian provinces. To this end, Registered Entities from these provinces are working with Natural Resources Canada and are using their own inputs to develop a Benchmark GMD Event and/or Supplemental GMD Event based on empirical data that will form the basis for seeking approval for any required investments with their respective regulatory authorities.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.* Dispersed Generation Resources):
Not Applicable

Requested information
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.* Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Canadian Registered Entities that meet the applicability specified in Sections 4.1 and 4.2 of the proposed TPL-007-2 Reliability Standard.
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The revision would be used, at a minimum, by IESO and Hydro One to avoid needing to seek remand to TPL-007-2 in Ontario, Canada. Working with CEA, IESO and Hydro One have engaged other Canadian Registered Entities to solicit feedback. Registered entities from Manitoba, Québec and Saskatchewan are supportive of a to TPL-007-2 as an option for Canadian Registered Entities to pursue. No Canadian Entity has voiced opposition to such a revision.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
No
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	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.

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

Reliability Principles	
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber-attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	YES

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	

For Use by NERC Only

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

Version History

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

2	June 28, 2017	Standards Information Staff	Updated template

Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal Comment Period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017

Anticipated Actions	Date
45-day formal comment period with additional ballot	February 2018
10-day final ballot	May 2018
Board adoption	August 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

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

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-5**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date: See Implementation Plan.**

B. Requirements and Measures

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities.

1.1.2. Known ~~-~~outage(s) of generation or Transmission Facility(ies) scheduled in ~~as selected in consultation with the Reliability Coordinator for~~ the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. ~~for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3~~Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s); and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

~~1.1.2.~~1.1.3. New planned Facilities and changes to existing Facilities.

~~1.1.3.~~1.1.4. Real and reactive Load forecasts.

~~1.1.4.~~1.1.5. Known commitments for Firm Transmission Service and Interchange.

~~1.1.5.~~1.1.6. Resources (supply or demand side) required for Load.

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-032 including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.

- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The analysis shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.4.4. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.4.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R3.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Remedial Action Scheme is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance

swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event (s) shall be conducted.

~~**4.2.1.** If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.~~

~~**4.2.2.** If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:~~

~~**4.2.2.1.** List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation.~~

~~**4.2.2.2.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.~~

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information~~. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.~~

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to

identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

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

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit

The applicable entity shall keep data identified in Measures M1 through M8 or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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

1.3. Compliance Monitoring and Enforcement Program As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Compliance Monitoring Period and Reset Timeframe:

Not applicable.

1.5. Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checks
- Compliance Violation Investigations
- Self-Report
- Complaints

1.6. Additional Compliance Information:

None.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-032 standards and other sources, including items represented in the Corrective Action Plan.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P8~~7~~) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P8~~7~~) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P8~~7~~) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4.	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P8~~7~~) in Table 1. OR	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P8~~7~~) in Table 1. OR	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P8~~7~~) in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6.	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC	

Version	Date	Action	Change Tracking
		has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	Adopted by the NERC Board of Trustees.	Revised To address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability (P0 through P8 events):

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only (P0 through P7 events only):

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only (P1 through P7 events only):

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes
P8 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	3Ø	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
   ~~d.~~ 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing. ~~3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.~~
   ~~e. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.~~

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	~~f. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.~~ ~~g.~~d. ~~3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Cleari~~ ~~h.~~e. 3Ø internal breaker fault. ~~i.~~f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)

10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
    a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times~~, e.g. sudden pressure relaying~~;
    b. A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported at a Control Center;
    c. A single station dc supply associated with protective functions required for Normal Clearing, and that single station dc supply is not monitored or not reported at a Control Center for both low voltage and open circuit;
    d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal Comment Period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017

Anticipated Actions	Date
45-day formal comment period with additional ballot	February 2018
10-day final ballot	May 2018
Board adoption	August 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

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

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-45**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

~~**5. Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

~~Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

~~For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:~~

- ~~P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)~~
- ~~P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)~~
- ~~P2-1~~
- ~~P2-2 (above 300 kV)~~
- ~~P2-3 (above 300 kV)~~
- ~~P3-1 through P3-5~~

- ~~P4-1 through P4-5 (above 300 kV)~~
- ~~P5 (above 300 kV)~~

~~B. Requirements~~

5. Effective Date: See Implementation Plan.

B. Requirements and Measures

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-~~010 and MOD-012 standards~~032 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities.

1.1.2. Known outage(s) of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with ~~a~~ the selected known outage(s); and

~~**1.1.1.1.**~~**1.1.2.2.** Does not exclude known outage(s) solely based upon the outage duration ~~of at least six months.~~ .

~~**1.1.2.**~~**1.1.3.** New planned Facilities and changes to existing Facilities.

~~**1.1.3.**~~**1.1.4.** Real and reactive Load forecasts.

~~**1.1.4.**~~**1.1.5.** Known commitments for Firm Transmission Service and Interchange.

~~**1.1.5.**~~**1.1.6.** Resources (supply or demand side) required for Load.

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-032 including items represented in

the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be ~~studied~~assessed. The ~~studies~~analysis shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to

experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

~~**2.4.3.**~~**2.4.4.** For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.

- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

~~2.4.4.~~**2.4.5.** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or ~~Special Protection Systems~~ Remedial Action Schemes.
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

~~**M1.**~~**M3.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R3.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a ~~Special Protection System~~Remedial Action Scheme is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an

evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event (s) shall be conducted.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated -in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information.~~. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.~~

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

~~**M2.**~~**M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

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

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit

The applicable entity shall keep data identified in Measures M1 through M8 or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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

1.3. Compliance Monitoring and Enforcement Program As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Compliance Monitoring Period and Reset Timeframe:

Not applicable.

1.5. Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checks
- Compliance Violation Investigations
- Self-Report
- Complaints

1.6. Additional Compliance Information:

None.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the ~~MOD-010 and~~ MOD-~~012~~032 standards and other sources, including items represented in the Corrective Action Plan.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P~~7~~8) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P~~7~~8) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P~~7~~8) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4.	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P~~7~~8) in Table 1. OR	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P~~7~~8) in Table 1. OR	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P~~7~~8) in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6.	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC	

Version	Date	Action	Change Tracking
		has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	Adopted by the NERC Board of Trustees.	Revised To address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability~~:~~ (P0 through P8 events):

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

~~-~~Steady State Only~~:~~ (P0 through P7 events only):

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only~~:~~ (P1 through P7 events only):

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus ~~relay~~non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant ~~relay[13]~~component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

P8 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	3Ø	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)

10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.

11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

13. ~~Applies~~For purposes of this standard, non-redundant components of a Protection System to ~~the following~~consider are as follows:

    a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;

    b. A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported at a Control Center;

    c. A single station dc supply associated with protective functions ~~or types: pilot (#85), distance (#21), differential (#87), current (#50, 51~~required for Normal Clearing, and ~~67),~~that single station dc supply is not monitored or not reported at a Control Center for both low voltage ~~(#27 & 59), directional (#32, & 67),~~ and ~~tripping (#86, & 94).~~open circuit;

    d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level

   b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
   a. The estimated number and type of customers affected
   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M3. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M4.M1. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M6.M1. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M7.M1. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M8. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M9. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M10.M1. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

~~1. Compliance Monitoring Process~~

~~1.1 Compliance Enforcement Authority~~

~~Regional Entity~~

~~1.2 Compliance Monitoring Period and Reset Timeframe~~

~~Not applicable.~~

1.3 Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications

Spot Checking

- Compliance Violation Investigations

Self-Reporting

- Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.

The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.

- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in-force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

~~None~~

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability

	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~related need who requested the Planning Assessment in writing.~~

E.A. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved — Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in	

Version	Date	Action	Change Tracking
		accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	

Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal Comment Period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017

Anticipated Actions	Date
45-day formal comment period with additional ballot	February 2018
10-day final ballot	May 2018
Board adoption	August 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

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

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-5**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date: See Implementation Plan.**

B. Requirements and Measures

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities.

1.1.2. Known outage(s) of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s); and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

1.1.3. New planned Facilities and changes to existing Facilities.

1.1.4. Real and reactive Load forecasts.

1.1.5. Known commitments for Firm Transmission Service and Interchange.

1.1.6. Resources (supply or demand side) required for Load.

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-032 including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The analysis shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.4.4. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one

or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.4.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned

System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices

may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R3.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Remedial Action Scheme is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event (s) shall be conducted.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be

evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

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

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit

The applicable entity shall keep data identified in Measures M1 through M8 or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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

1.3. Compliance Monitoring and Enforcement Program As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Compliance Monitoring Period and Reset Timeframe:

Not applicable.

1.5. Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checks
- Compliance Violation Investigations
- Self-Report
- Complaints

1.6. Additional Compliance Information:

None.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-032 standards and other sources, including items represented in the Corrective Action Plan.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P8) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P8) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P8) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4.	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P8) in Table 1. OR	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P8) in Table 1. OR	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P8) in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6.	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC	

Version	Date	Action	Change Tracking
		has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	Adopted by the NERC Board of Trustees.	Revised To address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability (P0 through P8 events):

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only (P0 through P7 events only):

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only (P1 through P7 events only):

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes
P8 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	3Ø	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)

10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
    a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;
    b. A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported at a Control Center;
    c. A single station dc supply associated with protective functions required for Normal Clearing, and that single station dc supply is not monitored or not reported at a Control Center for both low voltage and open circuit;
    d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

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Implementation Plan

Project 2015-10 Single Points of Failure

Reliability Standard TPL-001-5

Applicable Standard(s)

- TPL-001-5 – Transmission System Planning Performance Requirements

Requested Retirement(s)

- TPL-001-4 – Transmission System Planning Performance Requirements

Prerequisite Standard(s)

- None

Applicable Entities

- Planning Coordinator
- Transmission Planner

Background

Reliability Standard TPL-001-5 revises the prior version of the TPL-001 standard in three key respects:

- To address reliability issues concerning the study of single points of failure on Protection Systems, as identified in Federal Energy Regulatory Commission (FERC) Order No. 754 issued September 15, 2011, and the NERC Planning Committee System Protection and Control Subcommittee and System Analysis and Modeling Subcommittee September 2015 report titled *Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;*
- To address directives from FERC Order No. 786 issued October 17, 2013, in which FERC approved Reliability Standard TPL-001-4~~; and~~, relating to:
    - modeling known outages with a duration of less than six months; and
    - adding stability analysis for the outage of major Transmission Equipment with a lead time of one year or more.
- To replace references to the MOD-010 and MOD-012 standards, which have been superseded by the MOD-032 Reliability Standard.

General Considerations

~~The 36-month~~This implementation ~~period for TPL-001-5~~plan provides 36 months until the effective date of the Standard, providing Planning Coordinators and Transmission Planners with time to update their annual Planning Assessments to include the new System models and studies required by the standard. This implementation period reflects consideration that Planning Coordinators and Transmission Planners will need time to develop, among other things:

- A ~~process~~procedure or technical rationale for ~~coordinating with the Reliability Coordinator which~~selecting known outages of generation ~~of~~and Transmission Facilities~~ of less than six months shall be represented in planning studies~~;
- A process for establishing coordination with protection engineers to obtain the necessary data to perform the single points of failure analysis required by the standard; and
- Additional base case models and analysis.

In addition, ~~the~~this implementation plan includes an additional 24~~-~~-month period for the development of Corrective Action Plans (CAPs) under TPL-001-5 to address newly-added studies for P5 and P8 planning events involving single points of failure on Protection Systems.

This extended implementation period for the part of Requirement R2, Part 2.7 that states: "Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1", acknowledges that failures to meet System performance requirements, identified during subsequent Planning Assessment(s), for single points of failure in Protection Systems may not be mitigated by an Operating Procedure during an interim period before a mitigating capital improvement is installed.

This implementation period reflects consideration that Planning Coordinators and Transmission Planners will need time beyond that provided to conduct the new studies and analysis to develop processes for coordination with asset owners and protection engineers to identify appropriate ~~Corrective Action Plan~~CAP actions and establish the associated timetables for completion. This includes~~:~~

- ~~Any~~ any necessary ~~Corrective Action Plans to address Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h required by TPL-001-5 Requirement R4 Part 4.6; and~~

~~Any necessary Corrective Action Plans~~CAP to address System performance issues for studies involving Table 1 Category P5 and P8 Multiple Contingency (Fault plus non-redundant component of a Protection System failure to operate) required by TPL-001-5 Requirement R2, Part 2.7 for the ~~following~~ non-redundant components of a Protection System identified in TPL-001-5 Table 1 Footnote 13~~, items 2-4:~~.

- ~~A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported~~

- ~~A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit~~
- ~~A single control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.~~

Lastly, the provisions related to ~~Corrective Action Plans~~CAP including Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3) are carried forward from the TPL-001-4 implementation plan.

Effective Date

TPL-001-5 – Transmission System Planning Performance Requirements

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Date for TPL-001-5 Requirement ~~R4, Part 4.6 and Requirement~~ 2, Part 2.7 associated with Table 1 Category P5 Footnote 13 items ~~2, 3,~~b, c, and d and ~~4~~P8

~~Entities shall not be required to comply with Requirement R4, Part 4.6 until 24 months after the effective date of Reliability Standard TPL-001-5.~~

Entitles shall not be required to comply with Requirement R2, Part 2.7 for the Table 1 Category P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items ~~2, 3~~b, c, and ~~4~~d or P8 until 24 months after the effective date of Reliability Standard TPL-001-5.

~~Note Regarding Corrective Action Plans~~

For CAPs developed to address failures to meet Table 1 performance requirements for P5 or P8 events only, Transmission Planners and Planning Coordinators shall not be required to comply with the section of Requirement R2, Part 2.7 that states: "Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments **but the planned System shall continue to meet the performance requirements in Table 1**", until 96 months after the effective date of Reliability Standard TPL-001-5.

Note Regarding CAPs

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval of TPL-001-4, or in those jurisdictions where regulatory approval is not

required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, ~~Corrective Action Plans~~CAP applying to the following categories of Contingencies and events identified in TPL-001-5, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-5:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

Initial Performance of Periodic Requirements

Each responsible entity shall complete the first annual Planning Assessment without CAPs for revised P5 or P8 in accordance with TPL-001-5 by the effective date of the standard.

Each responsible entity shall ~~complete~~develop any required ~~Corrective Action Plans~~CAP under ~~Requirement R4, Part 4.6 and~~ Requirement R2, Part 2.7 associated with the non-redundant components of a Protection System identified in Table 1 Category P5 Footnote 13 items ~~2, 3~~b, c, and ~~4~~d and P8 by 24 months after the effective date of Reliability Standard TPL-001-5.

Retirement Date

TPL-001-4 – Transmission System Planning Performance Requirements

Reliability Standard TPL-001-4 shall be retired immediately prior to the effective date of TPL-001-5 in the particular jurisdiction in which the revised standard is becoming effective.

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Mapping Document

Project 2015-10 Single Points of Failure TPL-001

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R1 **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. **1.1** System models shall represent: **1.1.1.** Existing Facilities	TPL-001-5, Requirement R1 **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **1.1.** System models shall represent: **1.1.1.** Existing Facilities.	Requirement R1 body. Updated referenced standard number in body of requirement. Requirement R1 Part 1.1.2 Consistent with FERC Order 786 Para 40, the six-month threshold that could exclude planned maintenance outages is eliminated. Additionally, the addition of Near-term Planning Horizon aligns this requirement with IRO-017-1 Requirement R4 which requires the Planning Coordinator and Transmission Planner to jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. **1.1.3.** New planned Facilities and changes to existing Facilities **1.1.4.** Real and reactive Load forecasts **1.1.5.** Known commitments for Firm Transmission Service and Interchange **1.1.6.** Resources (supply or demand side) required for Load	**1.1.2.** Known ~~-~~outage(s) of generation or Transmission Facility(ies) scheduled in ~~as selected in consultation with the Reliability Coordinator for~~ the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum: ~~**1.1.2.1.** for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3~~Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events	Assessment for the Near-Term Transmission Planning Horizon. Requirement R1 Parts 1.1.2.1, 1.1.2.2, and 1.1.2.3 Substantial regional differences exist for outage coordination methods and procedures, making it difficult to define specific known outage selection criteria pertinent to all. Therefore, considering the NERC SAMS recommendations, selection of known outages in the Near-Term Planning Horizon were limited to three primary considerations. Requirement R1 Part 1.1.2.1 A properly planned Transmission system should facilitate maintenance outages without Non-Consequential Load Loss (FERC Order 786, Paragraph 41).

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	in Table 1 when concurrent with the selected known outage(s); and ~~1.1.2.2.~~ Does not exclude known outage(s) solely based upon the outage duration. ~~1.1.2.~~1.1.3. New planned Facilities and changes to existing Facilities. ~~1.1.3.~~1.1.4. Real and reactive Load forecasts. ~~1.1.4.~~1.1.5. Known commitments for Firm Transmission Service and Interchange. ~~1.1.5.~~1.1.6. Resources (supply or demand side) required for Load.	Therefore, System models shall represent known outages in the Near-Term Transmission Planning Horizon that are expected to result in Non-Consequential Load Loss following a Table 1 P1 Event. It is noted that the performance requirements for all Table 1 Events include that the System shall remain stable, as well as Cascading and uncontrolled islanding shall not occur. Requirement R1 Part 1.1.2.2 Planned outages lasting less than six months could be overlooked when the Transmission Planner and Planning Coordinator formulate System models (FERC Order 786, Paragraph 42). Further, there is no correlation between the System impact of an outage and its duration. Therefore, while duration is an

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		acceptable factor to consider when selecting a known outage for representation in System models, the duration shall not be the sole factor for omission. <u>Requirement R1 Part 1.1.2.3</u> A technical rationale is necessary to establish a rules-based approach to the selection of known outages for representation in System models. Similarly, regional operational approaches and outage coordination procedures vary, but the selection of known outages should incorporate input from operational experience. Therefore, known outages shall be selected according to an established procedure or a technical rationale.
TPL-001-4, Requirement R2	TPL-001-5, Requirement R2	No modifications made.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Parts 2.1, 2.1.1, 2.1.2, 2.1.4 and 2.1.5 Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7, 2.7.1, 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	Parts 2.1, 2.1.1, 2.1.2, 2.1.4 and 2.1.5 Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7, 2.7.1, 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	
TPL-001-4, Requirement R2 2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.	TPL-001-5, Requirement R2 2.1.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.	Requirement R2 Part 2.1.3 A properly planned Transmission system should facilitate maintenance outages without Non-Consequential Load Loss, maintain a stable System without Cascading and uncontrolled islanding. (FERC Order 786, Paragraph 41). Therefore, consistent with the principle of TPL-001-5 Requirement R3, Part 3.4 which requires the Transmission Planner and Planning Coordinator to identify those planning events in Table 1 that are

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		expected to produce more severe System impacts on its portion of the BES, only those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES are to be assessed for System models that include known outages pursuant to Requirement R1 Part 1.1.2.
TPL-001-4, Requirement R2 2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: • Load level, Load forecast, or dynamic Load model assumptions.	TPL-001-4, Requirement R2 2.4.~~3~~. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: • Load level, Load forecast, or dynamic Load model assumptions. • Expected transfers.	TPL-001-5, Requirement R2, Part 2.4.4 TPL-001-4, Part 2.4.3 moved to TPL-001-5, Part 2.4.4

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
• Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.	• Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.	
	TPL-001-5, Requirement R2 2.4.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.	TPL-001-5, Requirement R2, Part 2.4.3 Modified the standard to add a Stability analysis requirement for P1 events in Table 1, with known outages under appropriate System conditions, that includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.3. For reasons similar to those justifying changes to Requirement R2 Part 2.1.3, the Transmission Planner and Planning Coordinator shall identify those P1 events in Table 1 expected to produce more severe System impacts on its portion of

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		the BES to be assessed for System models that include known outages pursuant to Requirement R1 Part 1.1.2.
	TPL-001-5, Requirement R2 2.4.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.	<u>TPL-001-5, Requirement R2, Part 2.4.5</u> Consistent with FERC Order 786 Para 89, modified the standard to add Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis stated in Requirement R2, Part 2.1.5 to address stability analysis for spare equipment strategy.
TPL-001-4, Requirement R3 **R3.** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for	TPL-001-5, Requirement R3 **R3.** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term	No Modification Made

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **3.1.** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4. **3.2.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5. **3.3.** Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:	Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **3.1.** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4. **3.2.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5. **3.3.** Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall: **3.3.1.** Simulate the removal of all elements that the Protection System and other automatic controls are expected to	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: **3.3.1.1.** Tripping of generators where simulations show generator bus voltages or high side of the generation	disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: **3.3.1.1.** Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. **3.3.1.2.** Tripping of Transmission	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. **3.3.1.2.** Tripping of Transmission elements where relay loadability	elements where relay loadability limits are exceeded. **3.3.2.** Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors. **3.4.** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
limits are exceeded. **3.3.2.** Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors. **3.4.** Those planning events in Table 1, that are expected to produce more severe	Contingencies selected for evaluation shall be available as supporting information. **3.4.1.** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. **3.4.1.** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are	mitigate the consequences and adverse impacts of the event(s) shall be conducted.	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
included in the Contingency list. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.		
TPL-001-4, Requirement R4 Parts 4.1, 4.1.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	TPL-001-5, Requirement R4 Parts 4.1, 4.1.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	No modifications made.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R4 4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.	TPL-001-5, Requirement R4, **R4.** For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **4.1.** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4. **4.1.1.** For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Remedial Action Scheme is not	<u>TPL-001-5, Requirement R4, Part 4.2</u> Prior to this change, TPL-001-4 Requirement R4, Part 4.5 discussed analysis performed during studies referenced in TPL-001-4 Requirement R4, Part 4.2. To eliminate confusion and better separate the discussion of studies and analysis from the discussion of the necessary pre-conditional selection of extreme events in Table 1 that are expected to produce more severe System impacts, identical language from Requirement R4, Part 4.5 was moved to Requirement R4, Part 4.2.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	considered pulling out of synchronism. **4.1.2.** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. **4.1.3.** For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner. **4.2.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5. If the analysis concludes there	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event (s) shall be conducted. ~~**4.2.1.** If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.~~ ~~**4.2.2.** If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible~~	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~actions designed to prevent the System from Cascading shall:~~ ~~**4.2.2.1.** List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation.~~ ~~**4.2.2.2.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.~~ **4.3.** Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: **4.3.1.1.** Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized. **4.3.1.2.** Tripping of generators where simulations show generator bus voltages or high side of the GSU	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. **4.3.1.3.** Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models. **4.3.2.** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers. **4.4.** Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information. **4.4.1.** Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	adjacent Systems which may impact their Systems are included in the Contingency list. **4.5.** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information~~. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.~~	
TPL-001-4, Requirement R5	TPL-001-5, Requirement R5	No modifications made.
TPL-001-4, Requirement R6	TPL-001-5, Requirement R6	No modifications made.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R7	TPL-001-5, Requirement R7	No modifications made.
TPL-001-4, Requirement R8	TPL-001-5, Requirement R8	No modifications made.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2015-10 Single Points of Failure TPL-001

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for Requirement R4 in Project 2015-10 and Single Points of Failure TPL-001. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

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

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Guidelines for Violation Risk Factors

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

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

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

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

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

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

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification for TPL-001-5, Requirement R1

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R1

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R2

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R2

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R3

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R3

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R4

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R4

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R5
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R5
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R6
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R6
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R7
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R7
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R8
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R8
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

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Project 2015-10 Single Points of Failure TPL-001

Cost Effectiveness

Known Outages FERC Order No. 786

FERC Order No. 786 Paragraph 40 directs a change to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. See paragraphs 33-45 for the discussion on planned maintenance outages.

Overview of Commission Determination (Paragraphs 40-45)

The commission stated in Order No. 786 Paragraph 41:

- For the reasons discussed below, the Commission finds that planned maintenance outages of less than six months in duration may result in relevant impacts during one or both of the seasonal off-peak periods.
- Prudent transmission planning should consider maintenance outages at those load levels when planned outages are performed to allow for a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load.
- We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability.
- A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding.

The Commission Disagreed with the following:

- Order No. 786 Paragraph 44: The existing TPL-001-4 for Category P3 covers generator maintenance outages, Category P6 covers transmission maintenance outages.
- Order No. 786 Paragraph 45: Planned outages of less than one year in duration should be addressed operationally by determining new operating limits and taking other actions to mitigate the planned outage.
- Order No. 786 Paragraph 45: Planned outages of less than six months is unnecessary since…10 year time frame.

Options Considered By Standard Drafting Team to Satisfy FERC Order

The following options considered by the NERC Standard Drafting Team for Requirement R1 Part 1.1.2 include (refer to SAMS recommendations):

Current Option (Draft 3):

1.1. System models shall represent:

1.1.1. Existing Facilities.

1.1.2. Known ~~-~~outage(s) of generation or Transmission Facility(ies) scheduled in ~~as selected in consultation with the Reliability Coordinator for~~ the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. ~~for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3~~Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s); and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

~~**1.1.2.**~~**1.1.3.** New planned Facilities and changes to existing Facilities.

~~**1.1.3.**~~**1.1.4.** Real and reactive Load forecasts.

~~**1.1.4.**~~**1.1.5.** Known commitments for Firm Transmission Service and Interchange.

~~**1.1.5.**~~**1.1.6.** Resources (supply or demand side) required for Load.

Option considered for Draft 3:

Requirement R1, Part 1.1.2 Known outages(s) of generation or Transmission Facility(ies) with duration of at least ~~six~~ four months and any other significant planned outages of generation or Transmission Facility(ies) with a duration of less than four months that are expected to produce more severe System impacts on its portion of the BES. ~~These~~ This outage coordination~~s are~~ is required to be performed for the season/load-levels that outages are normally planned at and shall be performed only in the Near-Term Transmission Planning Horizon.

Previous Option (Draft 2)

1.1.2 Known outage(s) of generation or Transmission Facility(ies) ~~with a duration of at least six months.~~as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

Standard Drafting Team Proposal for Requirement R1 Part 1.1.2

The SDT did not feel like a time duration alone would capture "significant outages". Additionally, the language allows PC's to develop a process for selecting "significant outages" to be studied in the Near-Term Transmission Planning Horizon.

Single Point of Failure of the Protection System

Based on Order No. 754 directive of September 15, 2011; NERC informational filing dated March 15, 2012; Section 1600 data request; and the 2nd NERC informational filing dated October 30, 2015, the SPCS/SAMS report to address the concern of Single Point Of Failure of a protection system:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure13" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure13" with "a component failure of a Protection System13."
- Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."[1]
- Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection System13 that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Revision By Standard Drafting Team to Satisfy FERC Order

Since some of the recommendations from the SPCS and SAMS report were so specific, there were no other options considered for the following:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and

- Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.

- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure" with "a component failure of a Protection System."

Different options were considered for footnote 13 language.

Current Option Footnote 13 (Draft 3)

1. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
   - A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times~~, e.g. sudden pressure relaying~~;
   - A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported at a Control Center;
   - A single station dc supply associated with protective functions required for Normal Clearing, and that single station dc supply is not monitored or not reported at a Control Center for both low voltage and open circuit;
   - A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing.

Previous Option Footnote 13 (Draft 2)

The previous option was to have footnote 13 list four of the five components of a protection system but limit *"communications systems"* to only those that are not monitored or alarmed. The following is language for Footnote 13[1]:

13. For the purposes of P5 of this standard, components of a Protection System include the following:

    a. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;

    b. A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported;

[1] Failure of voltage and current sensing device would result in a breaker operation without a fault which was considered not a reliability risk to the BES.

c. A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;

~~a.~~d. A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices.

Standard Drafting Team Proposal for Table 1 Footnote 13:

The Standard Drafting Team added clarifications to the previous draft option which expands Protection System components to be considered to determine the impact to the BES if that component failed when a fault occurs.

Extreme Events and P8 Category:

The SPCS and SAMS report for Order No. 754 recommended that three phase faults involving single points of failure of a protection system be addressed. Additionally, the standard drafting team recognized that the Order No. 754 data requirement collected data for a three-phase fault and not a single-line-ground fault. The Order No. 754, Section 1600 data collection and report indicated a risk to the BES for three phase faults followed by single points of failure of a protection system. Therefore, the SDT decided to make Category P8 planning event if a three-phase fault following by a single points of failure resulted in Cascading or instability.

Revision By Standard Drafting Team to Satisfy FERC Order

Current Option (Draft 3):

~~4.2.~~ Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event (s) shall be conducted.

4.2.1. ~~If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.~~

~~4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:~~

~~4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementationList System deficiencies, the associated actions, and an associated timetable for implementation needed to prevent the System from Cascading.~~

~~4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.~~

Previous Option (Draft 2):

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.2.1. If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:

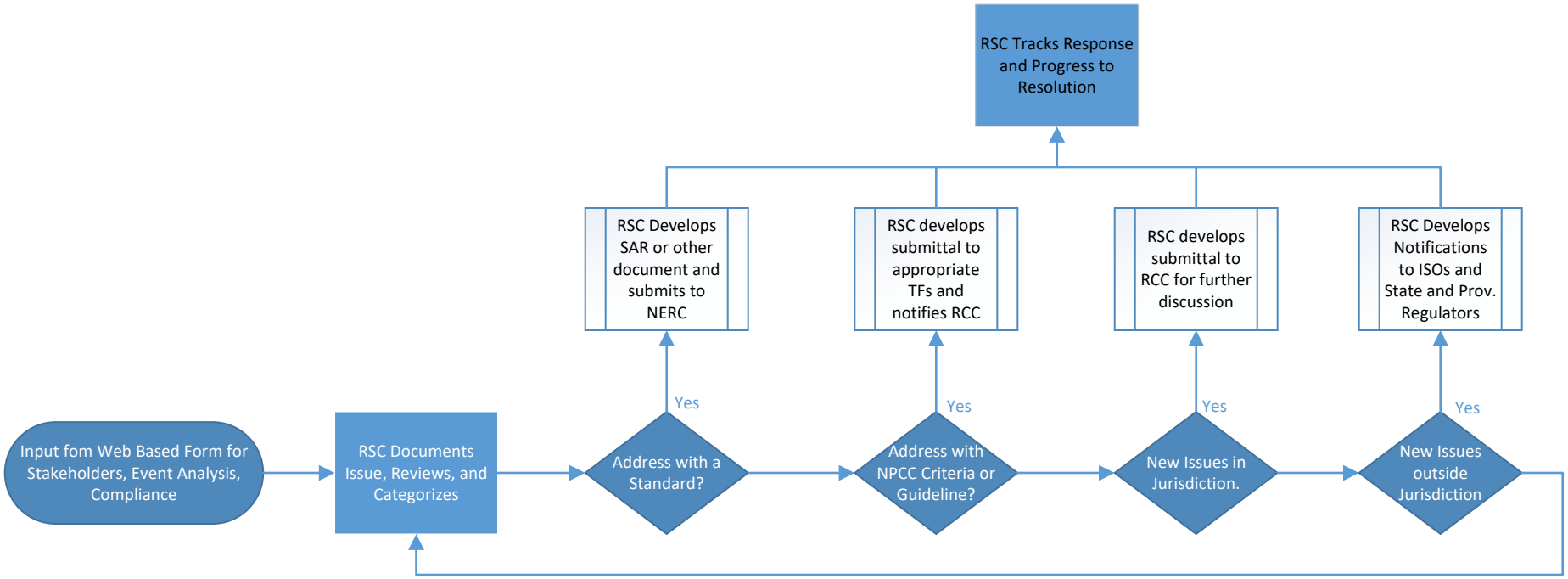
4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation~~List System deficiencies, the associated actions, and an associated timetable for implementation needed to prevent the System from Cascading~~.

4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

Standard Drafting Team Proposal

The standard drafting team feels that there is a reliability risk to the BES if Cascading or instability results in a three-phase fault followed by single point of failure of a protection system. There was confusion in the industry with the language that was similar to a CAP but not exactly a CAP. Therefore, the standard drafting team decided to create a P8 planning event which required a CAP if Cascading or instability occurs.

RSC-Approach to Addressing DER Risks to the BES



Input Review and Document Track Resolve

Distributed Energy Resources

Technical Considerations for the Bulk Power System

Staff Report

Docket No. AD18-10-000

February 2018

The opinions and views expressed in this staff report do not necessarily represent those of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission.

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Executive Summary

Traditionally, distributed energy resources (DERs) referred to small, geographically dispersed generation resources, such as solar or combined heat and power (CHP), installed and operated on the distribution system at voltage levels below the typical bulk power system levels of 100kV. In recent years, DER installations have increased significantly in some regions of the United States due in part to technology advances and state energy policies. This report considers how the increasing penetration and integration of DERs in specific regions may affect bulk power system reliability. This report focuses primarily on the technical considerations for DERs as they are currently operated, and does not necessarily address how DERs may participate in the markets operated by the regional transmission organizations and independent system operators (RTOs/ISOs).

To this end, FERC staff performed a series of technical assessments using industry power system models and commercially available power system simulation software to identify the potential reliability issues and likely benefits to the bulk power system resulting from an increased penetration of DERs.

Staff's work identified, at a high level, several key topics that are addressed in this report and can be summarized as follows:

- The impact of the current common industry modeling practice of netting DERs with load,[1] which may mask the effects of DER operation;
- DER capabilities for voltage and frequency ride through during contingencies;
- The potential for improved customer-level voltages due to the unloading of the bulk power system associated with the location of DERs at or near customer loads;
- Potential effects on system-wide transmission line flows and generation dispatch due to changing load patterns; and
- The sensitivity of voltage or power needs to different types of DER applications (i.e., the provision of energy, capacity, or ancillary services).

Overall, the results of this analysis suggest that increasing DER capacity, if not properly accounted for, could cause reliability concerns for the bulk power system.[2] Further industry discussion is needed to improve and refine the data that is available for

[1] Such as described in NERC Reliability Standard MOD-032-1 — Data for Power System Modeling and Analysis, requiring Load Serving Entities to aggregate Demand at each bus.

[2] DER capacity modeling was based on current trends for technology types, operational capabilities, and deployment distributions.

DERs that will be incorporated into planning and operating models. Collecting and using the most current and accurate data is key to getting a complete picture of how DERs affect the bulk power system.

In addition, further discussion and study is needed regarding other issues, such as sensitivities with higher DER penetration levels, changes in siting patterns, and potential impacts to the system's response to events, disruptions and outages, including frequency events. Further exploration in these areas will help the Commission to track and assess the impact of changing conditions on the bulk power system to identify emerging trends and address potential future reliability challenges.

1. Background

DER adoption is growing in the United States, due in part to state, local, and federal policies. In 2016, DERs accounted for about two percent of the installed generation capacity in the United States, but distributed solar photovoltaic (PV) installations alone represented over 12 percent of new capacity additions.[3] Certain regions have experienced disproportionately greater growth in the installed capacity of DERs. For example, California currently has over 7,000 MW of installed DER capacity[4] as shown in Figure 1, and has set a target to integrate 12,000 MW[5] of DERs by 2020.[6]

[3] Twenty-four gigawatts of new utility-scale generating capacity and 3.4 gigawatts of new distributed small scale photovoltaic were added in 2016 according to the U.S. Energy Information Administration. *See Renewable Generation Capacity Expected to Account for Most 2016 Capacity Additions*, the U.S. Energy Information Administration, (January 2017), *available at* https://www.eia.gov/todayinenergy/detail.php?id=29492 and *Electric Power Monthly – Chapter 6: Capacity*, the U.S. Energy Information Administration, (February 2016 with data for December 2016), *available at* https://www.eia.gov/electricity/monthly/current_year/february2017.pdf.

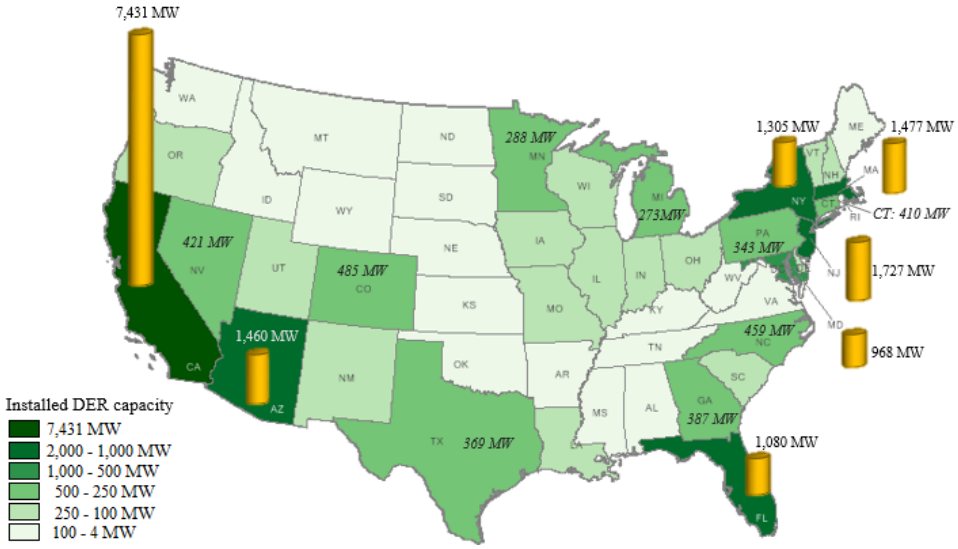
[4] *See Electric Power Sales, Revenue, and Energy Efficiency - Form EIA-861*, the U.S. Energy Information Administration, Release Date: October 6, 2016 with final 2015 data, Next Release date: October 2017, *available at* https://www.eia.gov/electricity/data/eia861/index.html and *Form EIA-861M (formerly EIA-826)*, the U.S. Energy Information Administration, Release Date: February 2017 for December 2016 data, *available at* https://www.eia.gov/electricity/data/eia861m/.

[5] The 12,000 MW goal does not include energy storage. The energy storage procurement target is set in Assembly Bill 2514 (California's investor owned utilities must procure 1,325 MW of energy storage by 2020) and Assembly Bill 2868 (California's investor owned utilities must procure up to 500 MW of additional distributed energy storage). *See* Energy Storage Systems, A.B. 2514, Skinner. (2009-2010), *available at* http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514 and Energy Storage, A.B. 2868, Gatto. (2015-2016), *available at* https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB2868. (2015-2016), *available at* https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB2868.

[6] *See* Clean Energy Job Plans, Office of the Governor Edmund G. Brown Jr., at 3 (September, 2011), available at https://www.gov.ca.gov/docs/Clean_Energy_Plan.pdf.

Further, even without regional policies encouraging DER growth, factors such as customer desire for self-supply, environmental considerations, and declining acquisition costs of DER technologies suggest continued DER growth, and the experience in other countries illustrates the rapid pace at which deployment can occur.[7]

Figure 1 – U.S. DER Deployments



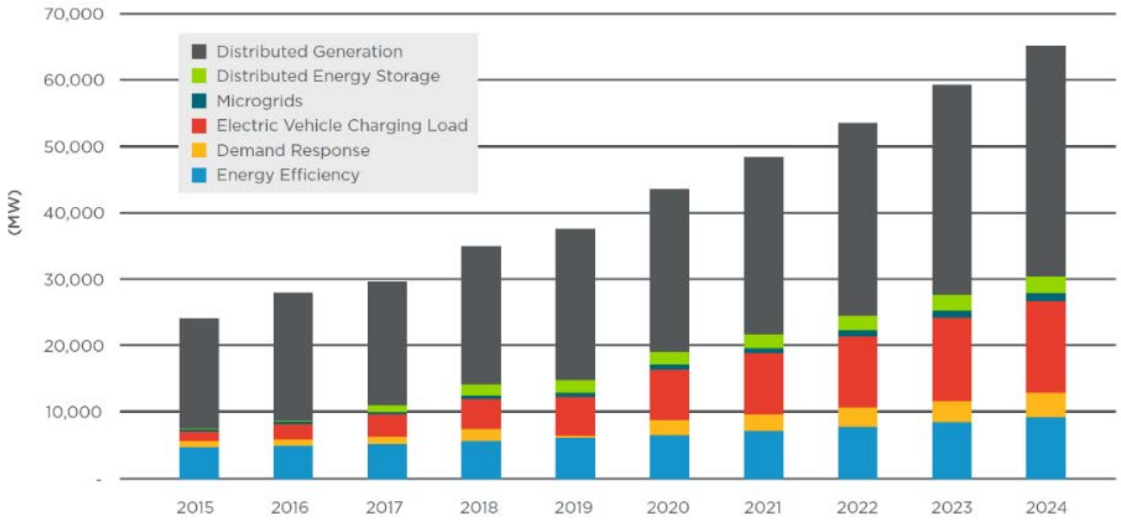
Source: The U.S. Energy Information Administration[8]

Figure Figure 2 below illustrates the estimated and projected annual installed DER capacity additions for the United States during 2015-2024. With several states setting high renewable energy procurement targets, installed capacity could rise rapidly.

[7] Germany added 7,400 MW of solar PV on its low-voltage distribution grid in one year. *See* Martin Braun, *Integrating PV in Local Distribution Systems – Germany*, (December 2010), *available at* http://iea-pvps.org/index.php?id=9&eID=dam_frontend_push&docID=423.

[8] *See Electric Power Sales, Revenue, and Energy Efficiency - Form EIA-861*, the U.S. Energy Information Administration, Release Date: October 6, 2016 with final 2015 data, Next Release date: October 2017, *available at* https://www.eia.gov/electricity/data/eia861/index.html and *Form EIA-861M (formerly EIA-826)*, the U.S. Energy Information Administration, Release Date: February 2017 for December 2016 data, *available at* https://www.eia.gov/electricity/data/eia861m/.

Figure 2 – U.S. Annual Installed DER Power Capacity Additions by DER Technology, 2015-2024



Source: Navigant analysis[9]

2. Defining DERs

Although "distributed energy resource" is a common term in the energy industry, no uniform DER definition exists. Traditionally, DERs referred to small, geographically dispersed generation resources, such as solar or CHP, located on the distribution system.[10] Depending on their size and configuration, distributed energy generation resources could partially or completely offset consumer electrical demand. They could also feed surplus energy back into the distribution system or, in some cases, the transmission system.[11] However, the definition of DERs has evolved to include not only

[9] *See* Navigant, Take Control of Your Future, Part II: The Power of Customer Choice and Changing Demands, May 9, 2016, *available at* https://www.navigantresearch.com/blog/take-control-of-your-future-part-ii-the-power-of-customer-choice-and-changing-demands.

[10] *See* NARUC, *Distributed Energy Resources Rate Design and Compensation* (Nov. 2016), https://pubs.naruc.org/pub.cfm?id=19fdf48b-aa57-5160-dba1-be2e9c2f7ea0 (NARUC DER Manual) at 44.

[11] PJM has been facing reverse power flows to the transmission system as a result of DER output for some time. In 2012, the Net Energy Metering Task Force reported that 20 out of the 8,096 load buses had negative loads of 10 MWh or more in more than 350 instances during the Jan-Mar 2012 period. *See* Net Energy Metering Senior Task Force, *1st Read - Final Report and Proposed Manual Revisions* at 4-5, (June 2012), *available at* http://www.pjm.com/~/media/committees-groups/task-

generation resources, but also energy storage, energy efficiency and demand response resources. Indeed, distributed generation resources are often co-located with, for example, demand response resources, and may be bundled into net demand such that a utility may not be able to measure nor have specific information on the characteristics and/or performance of DERs in its service area.

In a recent proposed rule on electric storage and DER participation in wholesale markets, the Commission proposed to define a DER as:

A source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply equipment.[12] NERC's working definition of DER, as provided in a report from the NERC DER Task Force, is "any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System."[13] Some entities, such as the California Public Utility Commission (CPUC), have a more narrow definition of distributed generation that includes only renewable resources.[14]

NARUC uses a broad DER definition:

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forces/nemstf/postings/20120628-first-read-item-04-nemstf-report-and-proposed-manual-revisions.ashx. This trend has continued into 2016. *See* Ken Schuyler, *Net Energy Injections at Load Busses* at 3, (May 2016), *available at* http://www.pjm.com/~/media/committees-groups/committees/mrc/20160617-special/20160617-item-02-pjm-net-energy-injections-quarterly-review.ashx.

[12] *See Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,121, at P 1 (2016) (Storage NOPR). The Commission received several comments on this proposed definition. Staff cites this definition as an example and notes that the instant report does not choose a specific definition for DERs.

[13] See NERC, *Distributed Energy Resources: Connection Modeling and Reliability Considerations* (Feb. 2017), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf (NERC DER Task Force Report) at 1.

[14] *See California Public Utilities Code § 769 (a) (2015)*, CPUC, *available at* http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=769.

> A resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar PV, wind, CHP, energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).[15]

NARUC's report further argues that defining DERs should be a collaborative effort between utilities and state and federal entities because of the potential applications across the entire electric power system and energy markets.

While it is possible to define DERs as a single class of assets, it is also important to recognize differences within this asset class. For example, bulk power system reliability issues associated with DERs may differ depending on whether DERs participate directly in the RTO/ISO markets, or participate in retail compensation programs, such as net metering. DERs that participate directly in the RTO/ISO markets provide greater visibility of the resources to system operators because they generally provide their physical and operational characteristics to the RTO/ISO and are modeled and dispatched as part of the market's economic clearing mechanism.[16] As discussed further below, while it is possible for DERs that are participating in retail compensation programs to be modeled, dispatched and metered, we understand that the reporting of such information to bulk power system operators is limited, which in turn limits the operational awareness about those DERs that are not participating directly in the RTO/ISO markets.

DERs also comprise a number of different technologies, and the operational characteristics of those different technologies and how they are modeled, dispatched and metered must be considered when evaluating their potential reliability impacts on the bulk power system. Some DER technologies, like electric storage, are completely controllable, and their controllability offers opportunities for resolving operational constraints on the transmission and distribution systems. Variable DERs, like solar and

[15] NARUC DER Manual at 45.

[16] See, e.g., Docket No. ER16-1085-001, 155 FERC ¶ 61,229 (Order conditionally accepting CAISO's tariff revisions to facilitate participation of aggregations of DERs in CAISO's energy and ancillary services markets); and ER16-1085-001 (Letter order accepting CAISO's filing to comply with 155 FERC ¶ 61,229).

wind generation, require operators to forecast accurately their output to identify their potential effects on system constraints and other operational challenges. However, the advent of smart inverters, as discussed below, and the aggregation of DER technologies with complementary capabilities, can help mitigate some of the operational limitations posed by certain technologies.

3. Bulk Power System Reliability Considerations for DERs

The electric industry has recently conducted several analyses to better understand the unique characteristics of DERs, how they respond to system conditions, and how they may be deployed as compared to bulk power system generators. This section presents a survey of several of these findings and conclusions on how those unique characteristics may translate into potential reliability issues and benefits as DER penetration increases.

3.1 Potential DER Reliability Issues

The potential impact of DERs, in aggregate, on the bulk power system has captured the electric industry's attention in recent years.[17] NERC has asserted that greater levels of DERs highlight the "need to ensure reliability of the bulk power system during both normal operation and in response to disturbances."[18] While industry has identified several potential reliability issues such as impacts to operations and planning including modeling, ramping and load forecasting,[19] many of these issues can be managed with adequate DER data and visibility. As the ISO/RTO Council's (IRC) Emerging Technology Report explains, "data is a common theme running through the DER issue."[20] However, as discussed below, ensuring the provision of appropriate data to bulk power system planners and operators can be complicated.

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[17] *See* NERC, *Special Report: Potential Bulk System Reliability Impacts of Distributed Resources* (Aug. 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf (2011 NERC Report) at 1.

[18] NERC DER Task Force Report at 3.

[19] 2011 NERC Report at 19-20.

[20] ISO/RTO Council, *Emerging Technologies* (Mar. 2017), http://www.iso-rto.org/Documents/NewsReleases/PUBLIC_IRC_Emerging_Technologies_Report.pdf. (Emerging Technologies Report) at 11.

In this section, staff presents the following potential reliability issues identified by industry that may arise from increased DER penetration:

- The lack of DER data and the resulting implications for the operation, planning, and design of the bulk power system;
- The need for coordination between the settings and capabilities of resources connected to the bulk power system and DERs;
- The need for improved modeling practices and capabilities for DERs;
- The effect of DER daily generation profiles on system unit commitment and ramping needs; and
- The effect of distribution connected variable PV and wind output on day-ahead load forecasts.

3.1.1 The Lack of DER Data and the Implications for the Bulk Power System

Without adequate data, many bulk power system models and operating tools will not fully represent the effects of DERs in aggregate.[21] For example, the IRC has argued that North American ISOs and RTOs should have access to basic data about DERs in their respective territories, and that the location, size, and technological capabilities of DERs are examples of critical and reliable data needed to formulate a "comprehensive strategy for managing an increasingly distributed electricity system."[22] For example, in projecting the reliable and efficient management of an increasingly distributed grid, ERCOT highlights the need for the detailed collection of static DER data[23] from distribution service providers and transmission service providers to support various ERCOT grid monitoring functions.[24]

In most regions, there is no process in place to provide static DER data to bulk system operators and planners.[25] In many states with net metering programs, certain

[21] NERC DER Task Force Report at 3.

[22] *Id*. at 11.

[23] Data which is set, typically upon installation, such as the physical and electrical location of the device as well as its capacity, type and capabilities.

[24] ERCOT, *Distributed Energy Resources: Reliability Impacts & Recommended Changes* (Mar. 2017), http://www.ercot.com/content/wcm/lists/121384/DERs_Reliability_Impacts_FINAL.pdf (ERCOT DER Impacts Report) at 5.

[25] *Id*. at 20.

static DER data may be collected through the customer registration process, but additional effort would be needed for operators and planners to obtain that data. NERC has identified the need to further study what specific, static DER data is needed for operators and planners and whether the data to be shared can be standardized or are subject to regional variation.[26]

3.1.1.1 DER Visibility

In its 2016 Long-Term Reliability Assessment, NERC states that many utilities lack "sufficient visibility" of DERs.[27] This lack of visibility could present certain issues for bulk power system reliability, including a lack of situational awareness.[28] NERC has defined situational awareness as "ensuring that accurate information on current system conditions is continuously available to operators."[29] This information should include the potential impact of contingencies and must be comprehensive enough for operators to "rapidly and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations."[30]

In addition to the need for static DER data noted above, DER telemetry data (such as output) can allow transmission system operators to gain real-time visibility and situational awareness of behind-the-meter generation. Today, this visibility is limited

[26] NERC, *DER Data Collection Guideline Presentation* (Aug. 2017), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSWG_Meeting_Presentations_-_August_2-3_2017_Atlanta_GA.pdf at 13.

[27] NERC, *2016 Long-Term Reliability Assessment* (Dec. 2016), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf at viii.

[28] CAISO, *Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid* (June 2017), http://morethansmart.org/wp-content/uploads/2017/06/MTS_CoordinationTransmissionReport.pdf at 8.

[29] *See* NERC, *Real-Time Tools Survey Analysis and Recommendations* (Mar. 2008), http://www.nerc.com/comm/OC/Realtime%20Tools%20Best%20Practices%20Task%20Force%20RTBPTF%2020/Real-Time%20Tools%20Survey%20Analysis%20and%20Recommendations.pdf at 9.

[30] *Id.*

because DERs are generally not required to supply telemetry data.[31] PJM explains that, while the telemetry data for some DER units may be available, "the process for obtaining the data varies based on the local distribution company."[32] Furthermore, PJM asserts that, depending on the level of penetration, DERs could require increased de-commitment/re-dispatch of centrally dispatched resources to meet balancing obligations.[33] The IRC supports the development of a framework by which "increasingly comprehensive operational data from the distribution system is provided as DER penetrations reach different thresholds."[34] A counter-balancing consideration when assessing the need for more DER information, including the granularity of the data, is the associated cost that DER owners will incur to provide the information. Requiring metering or telemetry equipment will impose a cost on DER resources, and that cost will need to be considered against the benefit of providing the additional information. Further, the degree to which statistical methods could use static data and telemetry data from a sample of DER may offer a cost effective real-time visibility without burdening every DER resource with the cost of telemetry equipment.

The CAISO region provides an example of how a lack of DER data can affect bulk power system operations such as unit commitment and dispatch. In 2016, distributed PV totaled 4,903 MW and represented over 10 percent of CAISO's peak load.[35] Behind-the-meter DERs are not typically metered unless participating in a

[31] *See* PJM, *PJM's Evolving Resource Mix and System Reliability* (Mar. 2017), , http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx (PJM Reliability Report) at 21.

[32] *Id.*

[33] *Id.*

[34] Emerging Technologies Report at 11.

[35] NERC DER Task Force Report at 33.

wholesale market program,[36] and can have the effect of reducing the measured load.[37] In CAISO, for example, a distribution circuit with a 10 MW load may see 5 MW of load at the circuit breaker, assuming a 50 percent penetration of solar PV. However, the underlying 10 MW load is still present, and as solar production declines in the late afternoon and evening, or as a result of cloud cover, this underlying load will remain high.[38] From the perspective of the bulk power system operator, the net load translates into lower than expected loads during the day with much faster increases of load through the late afternoon and evening than would be the case without DERs.[39] This results in low bulk power system unit commitment during the day, but very fast resource and ramping requirements in the late afternoon and evening.[40] These conditions may challenge the operational capacity of the system during some operating hours.[41]

As a result of netting DERs with load, CAISO has stated that it only becomes aware of the impact of rooftop solar when clouds block the sun and the demand previously served by rooftop solar suddenly appears.[42] On a clear sunny day, solar PV systems exhibit consistent energy output; however, when solar panels experience passing clouds, the solar PV exhibits intermittent energy production, as illustrated in Figure 3. Transmission operators have identified cloud cover as an issue in areas that have a large penetration of rooftop solar. It can cause a need for sudden ramping of other generation

[36] A behind-the-meter DER is "metered" if an electric meter collects data for the DER generation separately from the total net customer load. Usually this is not the case, and a single electric meter collects data for both the load and any DER generation behind the meter (for example small roof top PV have a single meter with the local load). This translates to an aggregate of all loads and DERs on a distribution circuit as a single net load from the perspective of the bulk power system. See ERCOT, *ERCOT Concept Paper on Distributed Energy Resources in the ERCOT Region* (Aug. 2015), , https://energy.gov/sites/prod/files/2016/02/f29/ERCOT_DER_Whitepaper_082015.pdf (ERCOT Concept Paper on DERs) at 34.

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

[38] *Id*. at 34.

[39] *Id*.

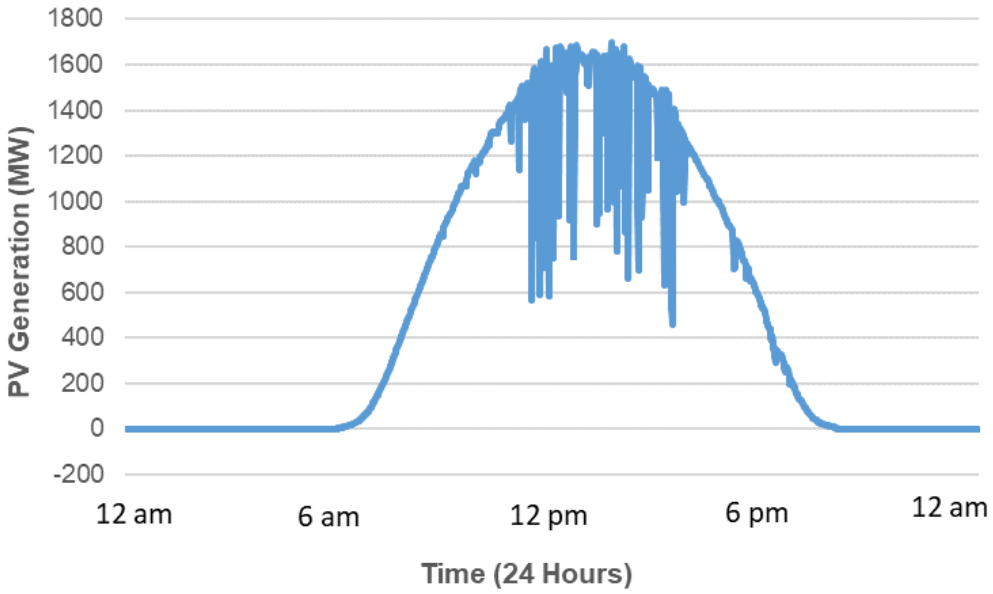
[40] *Id*.

[41] *Id*.

[42] Larson, *How are Distributed Energy Resources Affecting Transmission System Operators* (May 2016), http://www.powermag.com/distributed-energy-resources-affecting-transmission-system-operators/?printmode=1.

resources to balance the system load, as shown by the staff study summarized in Section 4.1 of this report.

Figure 3 – One-minute PV Generation during a Cloudy Day[43]



3.1.2 Coordination between the Bulk Power System and Distribution System

On November 4, 2006, one of the largest and most severe disturbances in Europe led to a blackout for more than 15 million European households. The Union for the Coordination of Transmission of Electricity (UCTE) prepared a Final Report[44] on the event, which contains information and analysis on the underlying causes of the November 4 disturbance, as well as lessons learned and recommendations to avoid a

[43] *See* EPRI, *Distributed PV Monitoring and Feeder Analysis*, http://dpv.epri.com/feeder_j.html.

[44] The UCTE is the association of Transmission System Operators in continental Europe. It aims at providing a reliable market place through the co-ordination of the operation of electric "power highways" over the entire European mainland. Union for the Co-ordination of Transmission of Electricity, *Final Report – System Disturbance on 4 November 2006* (Jan. 2007), https://www.entsoe.eu/fileadmin/user_upload/_library/publications/ce/otherreports/Final-Report-20070130.pdf (UCTE Report) at 12.

similar event in the future. The report discusses the contributions of DERs to the event, and offers DER-specific recommendations.

Analysis of the event showed that the proliferation of generating units connected to the distribution system increased the event's severity. During the event, cascading outages and tripped lines caused the UCTE grid to split into three separate systems. Without imports from the east, the western area of the split faced a supply-demand imbalance of about 8,940 MW.[45] This imbalance caused the frequency to drop to 49 Hz from the normal 50 Hz.[46] Immediately following the frequency drop, a significant amount of DERs, mostly consisting of wind and CHP units, tripped offline, which exacerbated the supply-demand imbalance and, by increasing the frequency deviation, led to further outages which increased the size of the event.[47] Furthermore, a lack of sufficient situational awareness meant that the transmission system operators did not have access to real-time data for DERs, preventing a better evaluation of system conditions.[48] Ensuring the visibility and situational awareness of DERs, as well as accurately modeling their response to events to avoid unforeseen tripping, could help prevent similar events in the United States as DER penetration levels increase. Further, new revisions to the Institute of Electrical and Electronics Engineers (IEEE) 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems are expected to leverage recent technology updates by requiring ride through capabilities in newly interconnecting DERs, which would help to avoid a parallel event in the United States.[49]

The final UCTE Report recommended several steps be taken to address the different disconnection requirements between generators connected to the transmission system and those connected to the distribution system, in light of the role of DERs in the November 4 event. Specifically, the UCTE Report recommended that "requirements to

[45] *Id*. at 25.

[46] *Id*. at 25.

[47] Since DERs are connected to the distribution grid, the relevant standards for their performance during a frequency drop are less constraining than those connected to the transmission grid. At the time of the event they typically would have to withstand a frequency drop to 49.5 Hz. A significant amount of DER units tripped during the event because the frequency dropped below the predefined threshold of 49.5 Hz. *Id.* at 25.

[48] *Id*. at 7.

[49] Staff notes that while the IEEE 1547 provides a uniform standard for the interconnection of distributed resources, it must be adopted by a jurisdiction to have effect.

be fulfilled by generation units connected to the distribution grid should be the same in terms of behavior during frequency and voltage variations as for the units connected to the transmission network…these requirements should be applied also to units already connected to transmission and distribution grids."[50] The UCTE Report also recommended that transmission system operators receive on-line data of generation connected to the distribution provider[51] grids (in at least one-minute increments).[52]

In the U.S., the topic of interconnection requirements has received attention as well. In a 2013 report, NERC found that a lack of coordination between small generating facilities and the bulk power system can lead to events where system load imbalance may increase during frequency excursions or voltage deviations, due to the disconnection of DERs, which in turn may exacerbate a disturbance on the bulk power system.[53] Relevant to that issue, in Order No. 828,[54] the Commission revised the *pro forma* Small Generator Interconnection Agreement (SGIA) to harmonize voltage and frequency ride through requirements for newly interconnecting small generating facilities (no larger than 20 MW) with those already in place for large generating facilities (larger than 20 MW). Order No. 828 requires newly interconnecting small generating facilities to meet the same requirements as large generating facilities to ride through abnormal frequency and voltage events (i.e., to not disconnect during such events).[55] While Order No. 828 applies only to generating facilities interconnecting to Commission-jurisdictional facilities through an SGIA, the Commission communicated its hope that the rule would be helpful to states when updating their own rules for interconnection to the distribution system,

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[50] *Id*. at 62.

[51] As defined by the *NERC Glossary of Terms* (Aug. 2017), http://www.nerc.com/files/glossary_of_terms.pdf.

[52] *Id*. at 62.

[53] *See* NERC, *Integration of Variable Generation Task Force Draft Report: Performance of Distributed Energy Resources During and After System Disturbance* (Dec. 2013), http://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20I1/IVGTF17_PC_FinalDraft_December_clean.pdf.http://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20I1/IVGTF17_PC_FinalDraft_December_clean.pdf.

[54] *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, 156 FERC ¶ 61,062 (year) (Order No. 828).

[55] *Id.* at P 21.

while acknowledging that states are under no obligation to adopt the provisions of the Commission's proposal.[56] As discussed below, technical DER interconnection standards, such as the IEEE 1547 Standard, are increasingly incorporating advanced features and grid friendly services such as ride through capabilities. However, in regions where clusters of DERs have already been installed without ride through requirements, NERC's 2013 observation remains relevant.

3.2 Potential Reliability Benefits of DERs

As DER penetration increases, there may be several associated reliability benefits to the bulk power system. For example, by providing power close to the customer, DERs can serve to reduce grid losses and reduce system peak load.[57] Several efforts are underway to better understand the full range of potential reliability benefits associated with DERs.[58]

3.2.1 Communication and Technological Capabilities of DERs

New revisions to the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems are expected to mandate communication capability from all DERs and standardize the related communication interfaces, protocols, and information models. NERC has commented that the revisions to IEEE 1547, coupled with smart inverter technology, could have substantial benefits for operations of distribution and transmission grids. NERC stated:

> Current work […] on enhancements to the IEEE 1547 interconnection requirements and how capabilities of DER are used will present opportunities for improving [bulk power system] reliability. Technology advances have the potential to alter DER from a passive "do no harm" resource to an active "support reliability" resource. From a technological

[56] *Id*. at P 12.

[57] *See* NYISO, *A Review of Distributed Energy Resources*, (Sep. 2014), http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Other_Reports/Other_Reports/A_Review_of_Distributed_Energy_Resources_September_2014.pdf at 18.

[58] *See, e.g.*, EPRI, *The Integrated Grid, A Cost-Benefit Framework* (Feb. 2015), http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004878.

> perspective, modern DER units will be capable of providing ERS [essential reliability services] and supporting [bulk power system] reliability.[59]

These revisions, once effective, would apply to new but not to existing DERs. However, the U.S. Department of Energy (DOE) estimates that the average life of small inverters is seven years, and thus inverter turnover will bring these new capabilities to an increasing proportion of deployed DERs. If the new revisions to IEEE 1547 mandate communication capability from all DERs, it would be the responsibility of the utility to build the required communication infrastructure to make use of this capability.[60] While transmission system operators may not presently be able to leverage all of these new features due to a lack of infrastructure, a great deal of work is underway at the Electric Power Research Institute (EPRI), the National Labs, NERC, and the National Institute of Standards and Technology's Smart Grid Interoperability Panel to develop ways to harness these new technical capabilities of DERs.

3.3 Developments at the Transmission-Distribution Interface: The DSO Model

Distributed System Operators (DSOs) are one of several different operational and business models that have been proposed and analyzed as a structure for distribution utilities in the future, especially with higher DER deployment.[61] DSOs have been proposed as a means to address the parallel needs of an efficient and reliable distribution system and an intermediate entity between the RTO/ISO and DER owners due to the limited visibility and control of DERs.[62] Paul De Martini of Newport Consulting Group and Lorenzo Kristov of CAISO outlined the potential functions of a "distribution system operator," including the ability to coordinate the interchange of power to other markets, physically coordinate DER schedules, aggregate DERs for wholesale market participation, and control resource output.[63] The DSO could be the medium by which RTOs/ISOs are provided with net load forecast and dispatchable DER products,

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[59] NERC DER Task Force Report at 4.

[60] *Id*.

[61] DER Task Force Report at vi.

[62] *See Distribution Systems in a High DER Future: Planning, Market Design, Operation and Oversight*, Paul De Martini and Lorenzo Kristov, Lawrence Berkeley National Laboratory, October 2015, (De Martini and Kristov).

[63] De Martini and Kristov at 21-23; *see also*, Apostolopoulou, *et al.*, *The Interface of Power: Moving Toward Distribution System Operators* (May 2016), http://ieeexplore.ieee.org/document/7452714/ (Apostolopoulou) at 3.

schedules and bids, metering, and telemetry. In turn, the RTO/ISO would send the DSO schedules, dispatch instructions, prices, and settlements for individual DERs or DER aggregations.[64] To enable these functions, the current distribution system may require certain upgrades to provide for better modeling, including upgrades to the data measurement and collection schemes to model existing DERs, as well as upgrades providing the capability to switch protection settings online and to communicate with DER resources.[65]

While a fully developed DSO as outlined by DeMartini and Kristov has yet to be implemented, several states are exploring regulatory and policy changes to overhaul the distribution system. Through its Reforming the Energy Vision (REV) initiative, the New York Public Service Commission has implemented changes through a series of orders to the structure of its electric system, including the development of distribution system platform (DSP) providers,[66] and has required distribution utilities in the state to file distribution system implementation plans. Other states, such as California, New Hampshire, Maryland, Massachusetts, and Ohio are also examining reforming the role of distribution utilities, particularly distribution system planning, during grid modernization proceedings, but not at the level being conducted in New York. Still other states, such as Rhode Island, are examining distribution system planning in much greater detail.

In addition, to explore the expanded role and responsibilities of DSOs and distribution utilities, DOE, in collaboration with the CPUC and the New York Public Service Commission, is developing a comprehensive set of functional requirements for a next-generation distribution system platform to enable participation of DERs in the provision of electricity services.[67] The project intends to engage key stakeholders to obtain a critical review of its efforts and aspires to provide guidance for the development

[64] Apostolopoulou at 3.

[65] *Id.* at 3.

[66] The DSP providers will be tasked with modernizing electric distribution systems to create a flexible platform for new energy products and services, and incorporating DERs into planning and operations to achieve the optimal means for meeting customer reliability needs. *See The Energy to Lead*, New York State Energy Planning Board, at 49 (2015), *available at* https://static1.squarespace.com/static/576aad8437c5810820465107/t/5797fc52f5e231d942a2d79b/1469578322990/2015-state-energy-plan-pf.pdf.

[67] *See Overview of DSPx*, DOE-OE, http://doe-dspx.org/.

of future planning, operations, and market tools needed to support distribution system platform implementation.

4. Technical Studies and Results

The need to study both the transmission and distribution systems becomes more important as DER penetration increases, because increasing DER penetration changes how the two systems interact. To assess the impacts of increasing penetration levels of DERs, Commission staff performed several technical studies using power flow, production cost, and distribution models to evaluate the potential reliability issues and benefits associated with DERs.

The power flow models provide information on the DER impacts to bus voltages and changes in power flows across the bulk power system following a contingency (such as the loss of bulk power system generation or DER generation). Production cost modeling offers information on the changes to dispatch and production costs of generation given various DER penetrations. OpenDSS[68] allows modeling of the distribution system and facilitates the analysis of the distribution system for a period of time such as a day. Several sources of data were used to reach consistent levels of DER penetration across the different study types and models to allow for comparison of results despite differences in modeling tools.

This section describes these studies, including the assumptions, methodology, and conclusions.

4.1 Role of Distribution Models in Planning Studies (Distribution Modeling)

Unlike typical power flow studies, this study uses the OpenDSS modeling tool to analyze the effects of DER installations on the distribution system over a period of a day and allows for extrapolation of potential impacts to the transmission system. Typical power flow studies assume a balanced three phase system, while distribution models typically portray individual phases[69] because many DER installations and distribution

[68] OpenDSS is a publicly available software modeling tool provided by EPRI. EPRI provides the tool and related distribution feeder models and sample data sets at no cost as part of their ongoing analyses of the impact of the variability of solar generation. This software has also been used for other industry studies, including multiple studies published with IEEE.

[69] Alternating electrical current circuits typically have three phases to efficiently move power. To minimize losses on bulk power system facilities these phases are

loads are single phase. It is important to consider the effects of DERs over a period of 24 hours to capture the influence of DER generation on feeder performance because DERs and load vary independently.

4.1.1 Study Purpose

The objective of the distribution feeder model study is to compare the potential impact of different types of feeder modeling on the effectiveness of planning studies, and therefore grid reliability. Feeders with DERs can be modeled three different ways: (1) as net demand (so the generation from the DER is cancelled by the load of customers); (2) as the aggregated generation of the DER independent of the aggregated load at the feeder connection; and (3) as a detailed model of the feeder. This is shown in Figure 4 below.

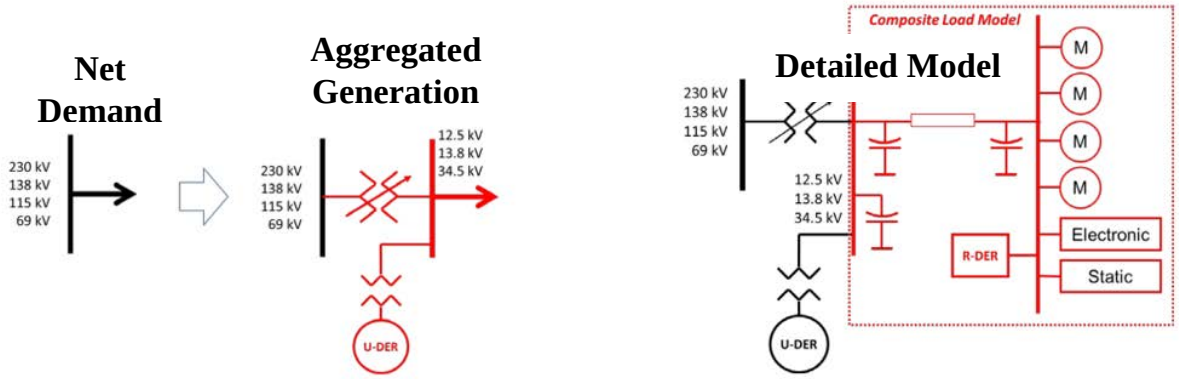


Figure 4: Types of DER Modeling[70]

In this study, staff evaluated the real and reactive power and voltages at the transmission and distribution interconnection points using the different types of DER models to assess whether different model types such as netted load or aggregated load and generation provide sufficient detail to assess reliability. Review of detailed models also provides insight into how DERs may behave during a variety of system conditions.

balanced, i.e. each phase carries the same amount of power. But on a lower voltage distribution circuit loads can be connected to single phases which often results in unbalanced power flow across the three phases.

[70] *See Reliability Guideline Distributed Energy Resource Modeling DRAFT*, NERC, Page 3 and 4, *available at* http://www.nerc.com/pa/RAPA/rg/ReliabilityGuidelines/Item_14._Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-05-09_-_FINAL_DRAFT.pdf.

4.1.2 Assumptions and Data

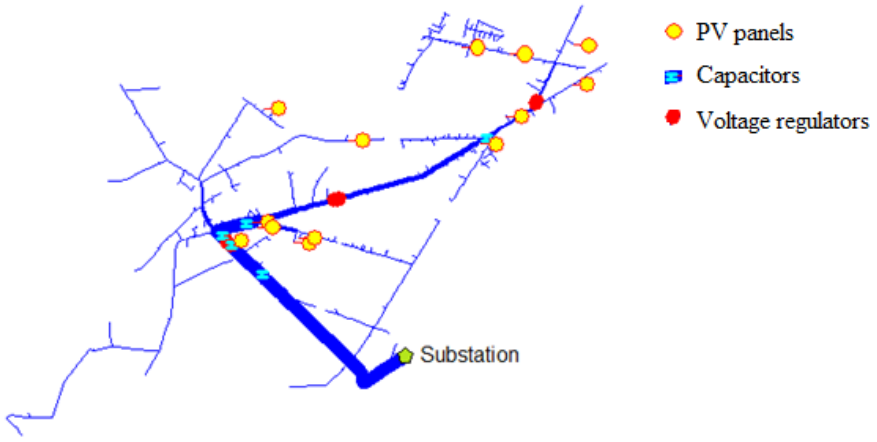
For the distribution feeder modeling, the distribution feeder models provided by EPRI[71] were used in combination with OpenDSS. This was not an attempt to model a full distribution system. The Feeder J1,[72] located in the northeastern United States, was selected because 1.7 MW of customer-owned PV systems already exist on the feeder. With a peak load of approximately 6 MW, this 12 kV feeder serves approximately 1,300 residential, commercial, and light industrial customers. While not a heavily loaded feeder, it requires the use of a load tap changer, voltage regulators, and switched capacitor banks to provide voltage regulation. Volt-Volt-Ampere Reactive (VAR) control was added to all PV units to assess the potential impact of the smart inverter functionality on both distribution and transmission operations.

The J1 feeder model used in the analysis consists of all primary and secondary power delivery elements from the substation transformer to the individual customers. Control elements such as load tap changers, capacitors (aqua marks in Figure 5) and voltage regulators (red marks in Figure 5) are included with fully implemented control algorithms using set-points, delays, and bandwidths. Load is allocated to each individual customer. The feeder peak load is about 6 MW and the substation peak load is 11 MW. Solar PV units (yellow marks in Figure 5) are interconnected at the customer service level (0.416 kV and 0.24 kV). Installed solar PV capacity is 1.7 MW or 28 percent of the peak feeder load and 15 percent of the substation load.

[71] Since 2010, EPRI has been conducting analyses to assess the variability of solar generation and its potential impact on utility operations and planning. As a part of the project, EPRI provides OpenDSS distribution feeder models and sample data sets at no cost. This software has also been used for other industry studies, including multiple studies published with IEEE.

[72] *See Distributed PV Monitoring and Feeder Analysis*, EPRI, *available at* http://dpv.epri.com/feeder_j.html.

Figure 5: Feeder J1 – location of voltage regulators, capacitors and PVs



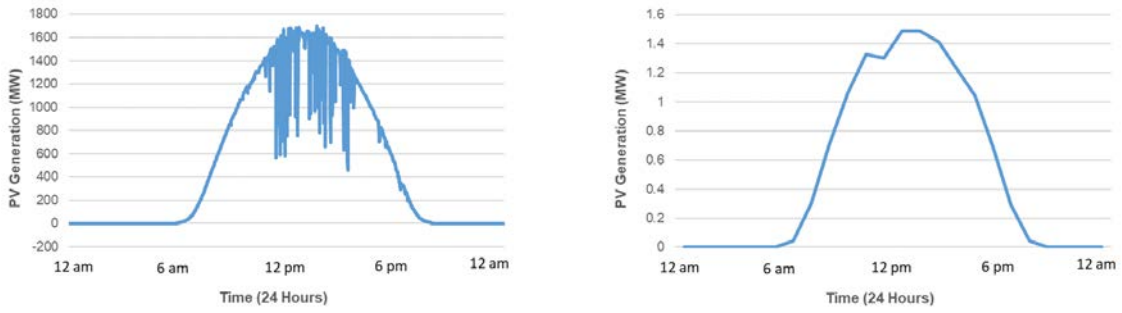
The J1 feeder model includes one year of the substation hourly real and reactive power measurement data and nine days of the measured solar PV generation data. Solar PV generation data is given for one-second, one-minute, fifteen-minute and one-hour time intervals.

4.1.3 Methodology

The study included models both with and without assumed distribution system voltage controllers, i.e., load tap changers, line regulators and capacitors. Staff also conducted a power flow analysis for both cases, and assessed the results using loading and voltage analyses.

Then, for the time series analysis results were generated for every minute during a 24-hour period, and the study considered three different cases of the feeder model: a full detailed model, an aggregated model, and a netted model. In each case, load was modeled using SCADA data and PV data was based on one minute EPRI data before being aggregated as needed to create the three different feeder models.

Figure 6: Hourly PV Diagrams



a) One-minute PV Generation Data b) Hourly average PV generation data

First, for the full detailed model both load and PV generation were modeled separately. For load, staff generated an hourly daily load diagram from the substation SCADA measurements by selecting a day when the peak demand occurred. Since the substation meters measure hourly net load, staff modified the measured values by adding an hourly solar PV generation profile. The hourly PV generation profile was calculated averaging one-minute PV data provided by EPRI over one hour (Figure 6). PV reactive power was neglected because a very small amount (less than 50 kVAr) was generated.

Second, staff aggregated the same load as a single load in the substation and aggregated the solar PV units as a single solar PV installation interconnected in the substation. In this case, staff derived the normalized hourly load data from multiple load profiles to represent "typical" hourly load data using statistical methods and incorporated it by replacing the entire feeder model with one aggregated demand and one aggregated solar PV installation in the substation.

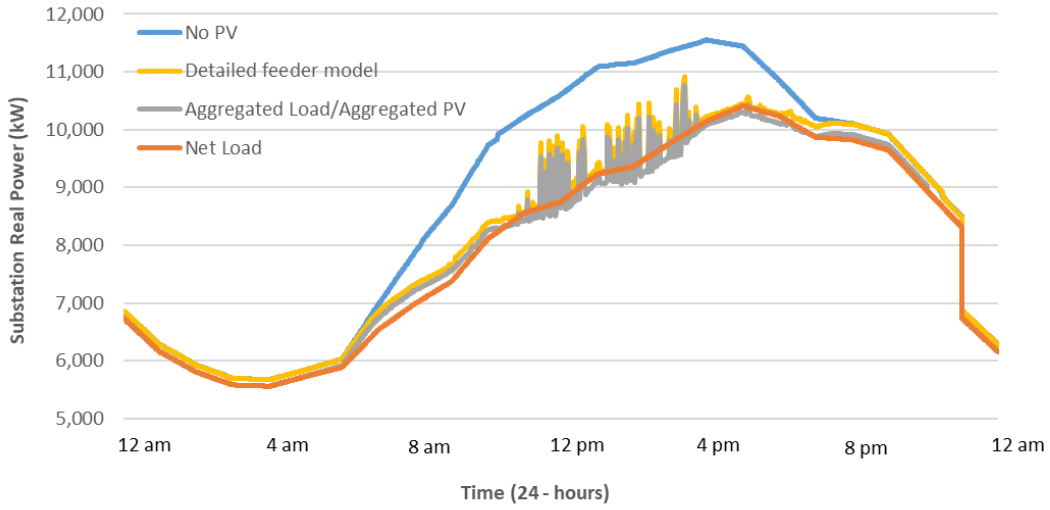
Finally, both load and solar PV installations were netted as one load located in the substation. The case used the normalized hourly SCADA data for the peak day to represent the net demand and solar PV generation as already included.

For all three cases, staff ran the time series analysis for every minute during a 24-hour period.

4.1.4 *Results*

The analysis found that DERs will modify the feeder load such that the variability of the load (both magnitude and frequency of change) will significantly increase relative to having no DER resources. However, this is only fully captured in the detailed model and partially captured in the aggregated models. It further found that based on the time series analysis results, the peak load change due to DERs may not be proportional to the installed capacity of DERs because the maximum DER generation may not be coincident with the feeder peak load. This demonstrates the need to develop planning processes that capture more detailed models of DERs and allow for modeling of the interface between the transmission and distribution systems to enable information exchange and more accurate calculations of the DER impact. The following figures illustrate how the current practice of netting DERs with load rather than using more detailed models may result in inaccurate estimates of power flowing on the system.

Figure 7: Substation Real Power

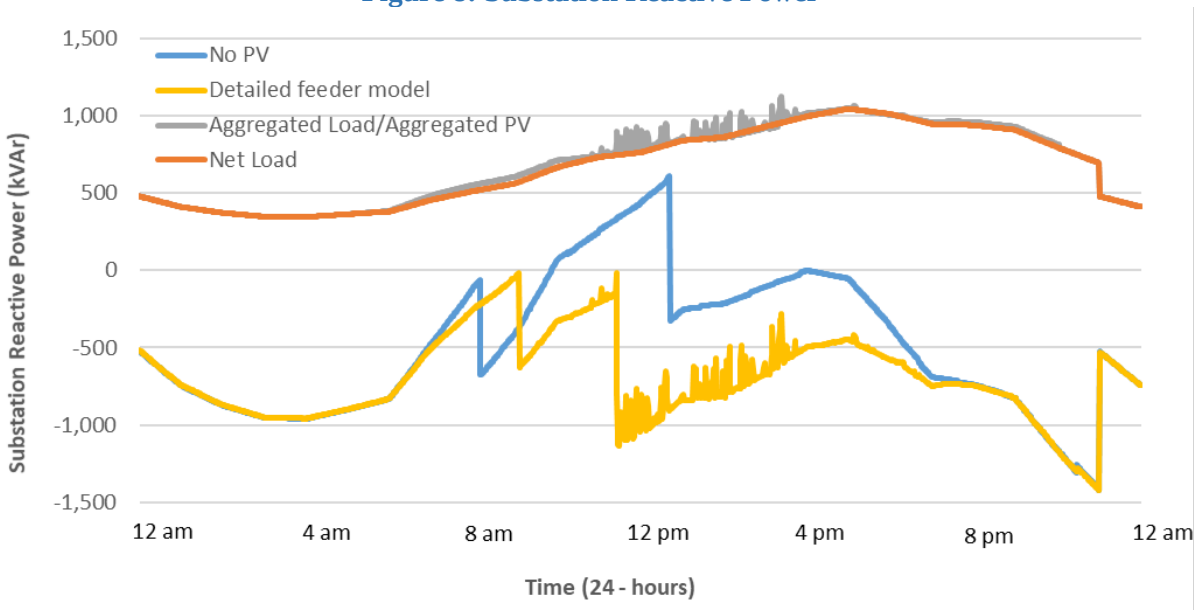


As shown in Figure 7, when the feeder is modeled as a net load, information about solar PV generation variability is not captured because the net load is usually an hourly average of the feeder load. The yellow line, representing the detailed model, shows significant variation. The grey line, representing aggregated load and solar PV data, shows less variation. The orange line, representing the net load model, shows none of the variation caused by the solar PV generation.

Therefore as shown here, when the solar PV aggregation is modeled separately from the load aggregation, the variability of the solar PV generation can be preserved. For the given feeder, when net load modeling is used, information on variability of PV operation is lost, causing a 12-percent difference in modeled load in comparison with the full feeder model. Because the load and generation data is combined when the feeder is modeled as an aggregated load and aggregated solar PV generation, the difference is much smaller (about 3 percent) or "smoother" as shown in Figure 6.

Figures 7 and 8 illustrate the difference between the detailed, aggregated and netted models and the limitations of the netted models.

Figure 8: Substation Reactive Power



4.2 DERs and System Performance Following Generator Outages (Power Flow Study)

4.2.1 Study Purpose

The objective of the power flow study was to assess how DERs, in a system with high DER penetration, may impact system power flows and bus voltages following a contingency. As DERs proliferate throughout the system, outages of DERs could have increasing impacts on the bulk power system, comparable to an outage of conventional generation. For example, a system disturbance causing DERs without ride through capabilities to automatically disconnect may exacerbate the initial system disturbance.

4.2.2 Assumptions and Data

The study utilized the FERC Form 715 planning cases for WECC and ERCOT.[73] Staff adjusted the 2017 peak load and low load cases for both regions to represent, as closely as possible, current DER penetration levels as reported by publicly available data

[73] These cases were used because they provide perspective on both interconnections, and their content and development process are familiar to most in the electric industry.

(approximately 12 percent penetration level in WECC and 0.02 percent in ERCOT).[74] However, because DER definitions vary and DERs are not yet explicitly modeled in WECC's FERC Form 715 power flow cases, staff made a few key assumptions and estimates regarding the amount and location of existing DER installations to identify load points for probable sites for the additional DER capacity to reach consistent penetration levels.

First, using commercially available data as a basis,[75] staff determined that the DER penetration in the WECC power flow case should be increased by approximately four percent (about 2,265 MW) over the amount determined to be included in Form 715 data to reflect a total of about 9,400 MW of DERs as currently reported within California.[76] Second, to determine where to place the additional DER capacity in the WECC power flow case, staff assumed that buses which included "aggregated generation and load models,"[77] also known as "complex loads," would constitute reasonable DER locations. These complex loads are modeled throughout the California electric system, and roughly match the location of DERs found in the PROMOD models. Therefore, staff added a total of 2,265 MW of DER capacity (as compared to the amount determined to be in the Form 715 data) to 1,010 load points throughout California in the WECC 2017 peak and low load planning cases to bring estimated modeled DER generation in line with capacity estimates prepared by the California Energy Commission.[78]

[74] Data sources, such as existing commercially available production cost and power flow models, and data collected by relevant public utility commissions and reported to the EIA were used to approximate both capacity and location of current DER facilities.

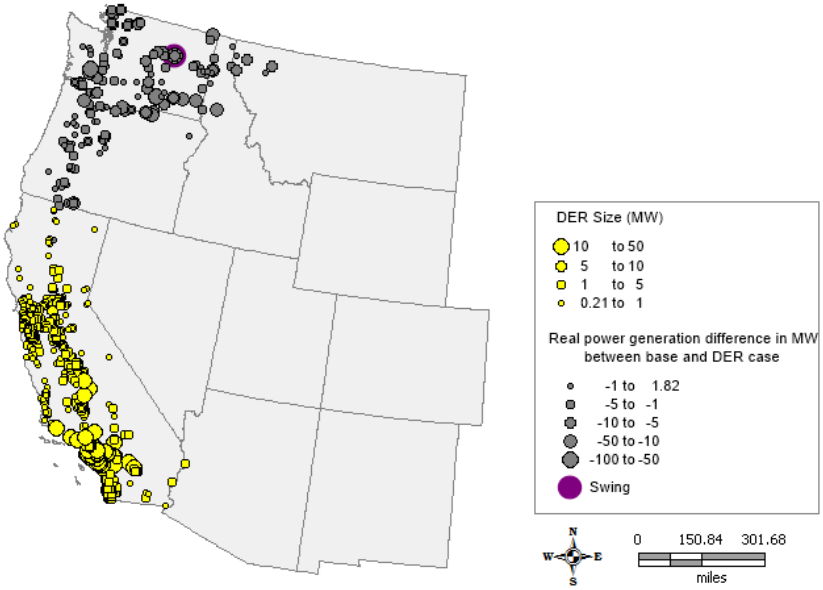
[75] This data was provided as part of the PROMOD databases developed by ABB.

[76] In WECC, the most detailed public DER data is collected by the California Energy Commission, which defines DERs as projects that are 20 MW or smaller, including both self-generation and projects for market participation. *See Renewable Energy Tracking Report 2016*, California Energy Commission, (last updated on December 22, 2016), *available at* http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

[77] *See* Reliability Guideline Distributed Energy Resource Modeling DRAFT, NERC, Page 3 and 4, *available at* http://www.nerc.com/pa/RAPA/rg/ReliabilityGuidelines/Item_14._Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-05-09_-_FINAL_DRAFT.pdf.

[78] *See Renewable Energy – Overview,* California Energy Commission, *available at* http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

Figure 9: Modeled Change in Generation in WECC



The location of these load points is shown in Figure 9. To maintain the generation and load balance across the entire WECC system, the team performed a production cost modeling study with similar levels of DER penetration to adjust generation.

In ERCOT, DERs are defined as an electrical generating facility that is located at a point of common coupling, 10 MW or less, connected to a bus voltage level less than or equal to 60 kV.[79] ERCOT has locational information for DERs with installed capacity greater than 1 MW that export energy into the distribution system because they are required to register with ERCOT, but it does not have detailed information for DER installations that do not meet that threshold. Based on this definition, and to match other data sources, staff determined that a total of 179 MW of DER capacity had to be added in the ERCOT 2017 peak and low load planning cases, as compared to the Form 715 data, to bring estimated modeled DER generation in line with the capacity estimates prepared by ERCOT.[80] To maintain the load and generation balance, an equivalent amount of generation from several large generating units was scaled down.

In order to determine the location of the DER installations, staff leveraged data from commercially available databases to site the DERs in the ERCOT power flow model based on their geographical proximity to the nearest distribution generator bus.

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[79] *See Distributed Generation*, ERCOT, (2017), *available at* http://www.ercot.com/services/rq/re/dgresource.

[80] *See Distributed Generation*, ERCOT, *available at* http://www.ercot.com/services/rq/re/dgresource.

The data for the unregistered component of the DER installations in ERCOT is available on an aggregate level by primary fuel type and load zone.[81] Staff divided the total capacity value of unregistered DERs proportionally among the buses identified by staff as probable DER locations. Table 1 shows the unregistered DER capacity as reported by ERCOT.

Table 1: Unregistered DER Totals[82]

Aggregate by Primary Fuel Type (MW) for Reporting Quarter 2016 Q4					
Load Zone	**Solar**	**Wind**	**Other Renewable**	**Other Non-Renewable**	Total
AEN	13.91	0.00	0.00	0.00	13.91
CPS	7.14	0.00	0.23	0.00	7.37
Houston	8.03	0.39	0.11	4.33	12.86
LCRA	0.64	0.00	0.00	0.00	0.64
North	68.46	1.66	0.00	0.63	70.74
Rayburn	0.00	0.00	0.00	0.00	0.**00**
South	11.27	0.67	0.00	0.00	11.94
West	5.93	0.82	0.00	0.33	7.08
Total	115.37	3.54	0.34	5.28	124.53

In additional sensitivity studies, staff also scaled DER generation by factors of two and three to test the effects of higher penetrations. To accommodate this additional generation, the existing generation fleet was re-dispatched based on dispatch results from a production cost modeling study with similar levels of DER penetration.

4.2.3 Methodology

The power flow study considers two fundamental system loading conditions: (1) high load, which typically occurs in the hot summer months; and (2) low load, which

[81] *Unregistered DER Capacity Quarterly Report*, ERCOT (last updated Quarter 1 2017) *available at* http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13544&reportTitle=Unregistered%20DG%20Installed%20Capacity%20Quarterly%20Report&showHTMLView=&micKey.

[82] *Unregistered DER Capacity Quarterly Report*, ERCOT (last updated Quarter 1 2017) *available at* http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13544&reportTitle=Unregistered%20DG%20Installed%20Capacity%20Quarterly%20Report&showHTMLView=&micKey.

typically happens during the spring or fall. The studies monitored for transmission facility loadings above 100 percent of Rating Set A (used for normal operations) and for bus voltages below 90 percent, below 95 percent, and above 105 percent of the standard operating voltage.

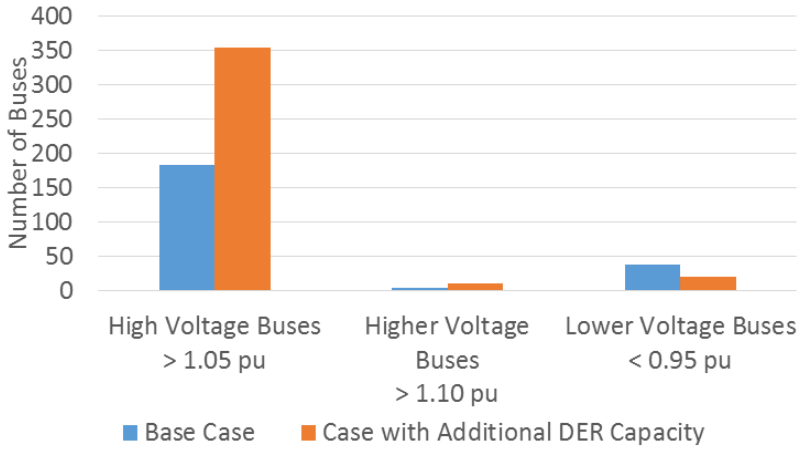
Finally, staff performed a selective contingency analysis to determine any violations to the thermal and voltage criteria. The contingencies examined included the loss of DER capacity, the loss of a large generating facility, and a combination of both. Staff also evaluated these contingencies at different DER penetration levels. The following contingencies were analyzed:

- Loss of bulk power system generation equal to one or two nuclear units
- Loss of levels of DER generation equal to one or two nuclear units
- Loss of both the one or two nuclear units on the bulk system and DER generation

4.2.4 Results

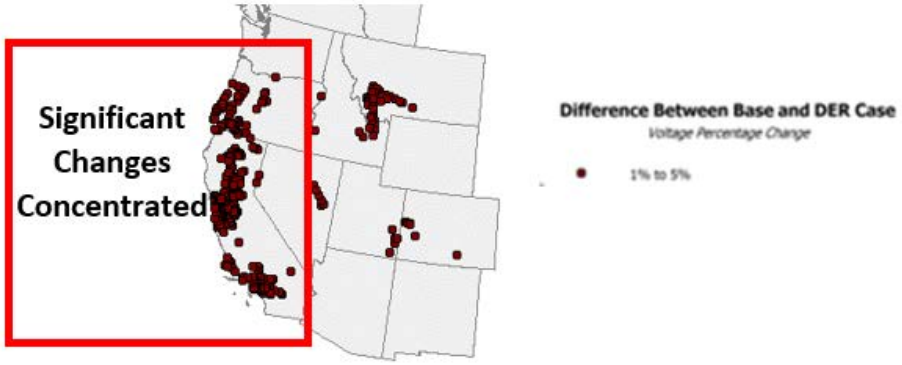
As shown in Figure 10 below, analysis of the WECC system found that in most cases, higher DER penetrations resulted in fewer buses with low voltages and thermal overloads but a greater number of buses with high voltages when compared to the base case. The increased voltages may be helpful on buses that tend to have low voltage issues, but potentially challenging to those with voltages that are already high. Bus voltages can in some cases increase with DER generation because it reduces loads and relieves loading on some transmission facilities.

Figure 10: Change in California Voltage Levels in WECC Cases



Voltages changed throughout WECC, with voltages generally increasing in load pockets closest to the additional DER capacity and varying in direction and magnitude of change elsewhere. Figure 11 shows that the most significant changes are close to the new DER capacity, but due to changes in power flows, there are smaller voltage changes throughout the system. Voltage changes are also influenced by the ability of some transformers to adjust their voltage output based on system conditions.[83]

Figure 11: Significant Voltage Changes Concentrated near DER Resources[84]

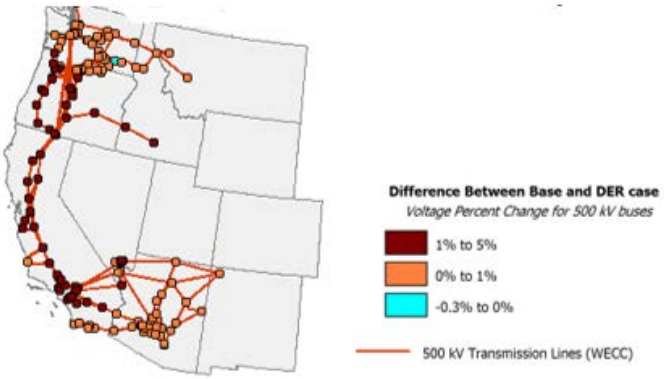


The small changes in voltage can ripple through the entire WECC interconnection in response to a change in any part of the system (for example, the loss or addition of generation) that might affect the voltage at a transformer. The resulting changes in voltage highlight the need for additional study to define and articulate: ride-through requirements for deviations in voltage; voltage support required from DER at the point of interconnection or appropriate point on the system; voltage support strategies throughout the interconnections to define steady state and dynamic reactive resources that may be needed; and the need for detailed/accurate/validated modeling of the behavior of DER.

[83] Transformers with tap adjustors can change the number of core windings that determine the primary to secondary voltage relationship, in order to maintain a more consistent voltage output. Typically, the tap position on the primary side will adjust based on the voltage delivered there so that the secondary voltage remains constant.

[84] The analysis also observed effects in Canada, which are not reported here.

Figure 12: Changes on the 500kV System[85]

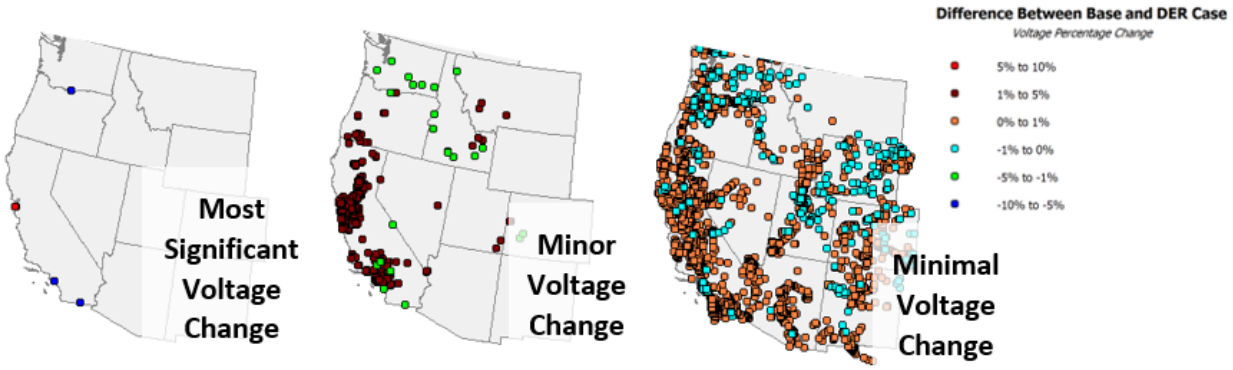


As shown in Figure 12, the large number of small changes in voltage that occurred in the modeled scenarios (between 0 and five percent) throughout the 500 kV system likely resulted from changes in flow patterns due to variations in load levels and generation re-dispatch to accommodate DERs. Due to the increase in DERs, staff decreased generation imports from the Northwest as well as load in California in the WECC power flow model to mimic the changes in dispatch identified in production cost modeling studies. As a result, in the model voltages on the 500 kV buses increased and smaller voltage shifts on lower voltage lines and buses also occurred. Power flow changes are also influenced by the ability of some transformers to adjust[86] their power output based on system conditions. The results shown in Figure 6 indicate that a closer look at the dispatch of reactive resources is needed to assess whether these changes in reactive support will need to be addressed in the future, e.g., with operating procedures or additional reactive equipment. The results mimic those identified in the production cost study below in Section 4.3, with similar levels of DER penetration. These effects are further shown in Figure 13 below.

[85] The analysis also observed effects in Canada, which are not reported here.

[86] Transformers with phase shifters are able to change the phase displacement between the input and the output voltage in order to control the active power passing through.

Figure 13: Buses with Large and Small Voltage Changes (Voltage Level Less than 100 kV)[87]



By comparison, analysis of the ERCOT system, with its lower levels of DER penetration, showed no significant variation in reliability impacts for voltages and thermal overloads under different contingencies. There was a slight increase in the number of thermal overloads, likely as a result of the clustering of DER capacity in a smaller number of locations on the system. Appropriate interconnection studies, curtailment procedures, and DER models will be needed to resolve these overloads in order to integrate large amounts of DER reliably into the ERCOT system.

After making changes to the settings as part of the power flow analysis, such as locking tap changers and switched shunt adjustments,[88] the percent change in bus voltages across the DER buses was no greater than 6 percent as increasing DER penetration levels were studied. This is due to the overall low penetration levels of DER capacity in ERCOT. However, while the average bus voltage increased at higher DER penetration levels similarly to the percentage changes found in WECC, increasing the DER penetration levels beyond a factor of three to a total penetration level of 0.05 percent at the identified set of DER buses prevented the case from converging, making further analysis impossible without broadening the electrical location of DERs throughout the model. Further studies taking into account alternative variables, such as changes in siting, may need to be conducted on the system to determine the impact of increasing DER penetration levels beyond a factor of three.

[87] The analysis also observed effects in Canada, which are not reported here.

[88] These are types of settings used in the power flow model to control how different devices respond to changes in voltage.

4.3 Impact of DERs on Dispatch (Production Cost Modeling)

4.3.1 Study Purpose

Staff performed production cost studies for WECC and ERCOT at both current and future DER penetration levels to evaluate the impact of DERs on generation dispatch and transmission constraints. Production cost modeling can simulate the operation of an electric system, within or outside of a market, as a least-cost optimization of unit commitment and dispatch to serve load while accounting for generator, system, and transmission constraints. This allows for the assessment of some high level reliability implications.

This analysis allowed staff to monitor the impact of different levels of DER penetration on generator dispatch, and congestion, to help identify common conditions that may create system stress.

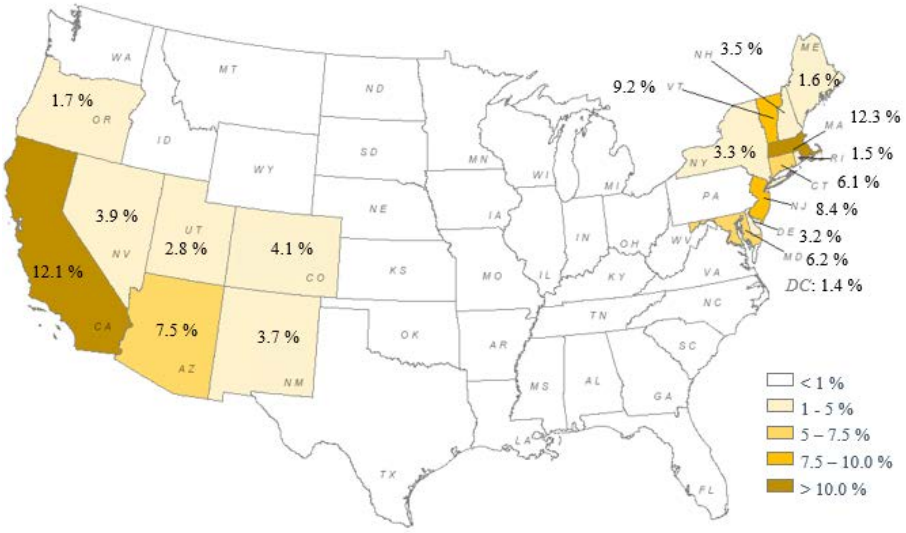
4.3.2 Assumptions and Data

The study modeled both WECC and ERCOT using the most recent nodal PROMOD databases. The models were prepared for a 2017 study year using escalations and recent forecasts included in the model for variables such as prices and load and set up to track emergency energy deployment and key generator characteristics, such as reserve participation and LMPs.[89]

Assumed DER capacity was increased by a total of 4,855 MW in the WECC model and 55 MW in the ERCOT model, as compared to the original models developed by ABB for the PROMOD production cost mode. These changes result in a penetration level of 12.5 percent for WECC in the updated model, rather than the three percent level in the original model.

[89] Staff notes that LMPs in this case are a proxy for the values associated with relieving transmission constraints, even though LMPs are not used throughout the WECC region.

Figure 14: Net Metering as a Percentage of State Peak Load[90]



This penetration level matches the 12.1 percent penetration level for California shown in Figure 14, which was calculated based on EIA data. Staff also evaluated a second future scenario with a 25-percent penetration level. More capacity could be incorporated into the system, but additional supporting infrastructure or other changes, such as new DER locations, may be needed.

For the ERCOT system, where there is a much lower amount of existing DER capacity, the original model included a penetration level of 0.01 percent. The updated model increased this penetration level to 0.02 percent, and two future-case scenarios were developed to evaluate penetration levels of 0.13 percent and one percent.

In both interconnections, the assumed DER capacity was sited and proportionally assigned hourly profiles to match existing installations in the models. Staff simulated randomized forced outages of both traditional and DER generators to assess the impact of different DER penetrations and dispatch capabilities on total system costs, LMPs, congestion, and loss of load expectation.

4.3.3 Methodology

Staff performed a one-year simulation for each scenario. Results were then reviewed on a monthly, and where possible, hourly basis. Results assessed included: generation dispatch changes, increases and decreases in production costs at the unit and regional level, variation in LMPs throughout the year, changes in congestion costs at flow gates over the year, monitoring of excess generation or any instances of unserved load to

[90] Data Source: EIA - Form EIA-826 detailed data files - Net Metering (December 2016) and Velocity Suite – Estimated State Load (Hourly).

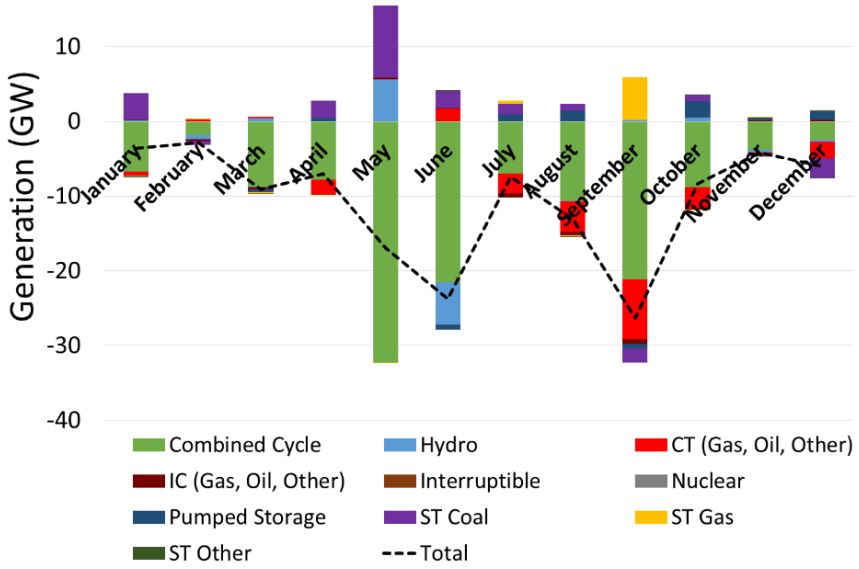
test for deliverability issues, and finally monitoring of reserve participation. Staff also reviewed these results at the nodal and area levels.

4.3.4 Results

In ERCOT, the scenario with 0.01 percent DER penetration level resulted in minimal changes in the dispatch of generation over the modeled year. In WECC, however, changes in LMPs, congestion costs, and therefore generator dispatch occurred frequently throughout the simulated year. The magnitude of these changes was limited due to the level of DER penetration and did not result in any loss of load hours or deployment of emergency energy.

As shown in Figure 15 below, increased DER capacity in WECC offset existing generation in the dispatch throughout the year, with the most significant changes occurring in late spring and fall. Increased DER capacity primarily replaced combined cycle gas generation, which is typically on the margin in WECC. However, it also caused minor increases in the dispatch of some steam coal and natural gas units, and affected the timing of the hydro dispatch. It is important to note that the PROMOD production cost model does not model forecast errors for either load or renewable generation. Therefore, the results do not provide insight into the impact of daily forecast uncertainty caused by variation in output from DERs such as variations in daily weather.

Figure 15: Monthly Generation Results for WECC Comparing Base Case and Additional DER Capacity Models



While the maximum and minimum LMPs changed slightly in the spring, the average LMP did not show a significant change overall, consistent with the other results and suggesting that the changes, while numerous, remain limited in magnitude at this

time. These changes were consistent with the relative increases and decreases in the dispatch of different generators.

In addition to the frequent dispatch variations, the effects were widespread throughout the WECC system even though the DER installations were largely located within California. The effects also changed depending on system conditions within the model for a given hour. This was particularly noticeable in generation dispatch, line flows, and congestion. Units were offset by DERs throughout WECC, and these changes caused both increases and decreases in congestion during the year.

Overall, transmission lines outside of California saw a decrease in congestion while those within California, especially near high concentrations of DERs, saw both increases and decreases. The increases in congestion could be caused by increased imports to areas with diminished use of some combined cycle units. However, given that the changes in congestion and dispatch were spread throughout the system and occurred at a wide variety of load levels and hours, additional sensitivities may need to be assessed in other studies to examine specific system conditions.[91] Because the model assumes the existing transmission system, effective planning for DER integration using accurate models could address any increases in congestion, though further study would be needed to confirm this conjecture.

4.4 Ancillary Services Provided by Energy Storage (Distribution Modeling)

4.4.1 Study Purpose

The energy storage study evaluates the impact of ancillary services provided by energy storage devices, such as regulation services, on markets, and transmission and distribution systems. Energy storage may be able to provide grid level services such as regulation, reserves and voltage support. However, the provision of these services from energy storage devices can result in sudden variations in output, affecting voltage and power quality on the distribution system, and potentially on the transmission system as well.

This study assesses whether a storage resource needs to be modeled separately from other DER installations due to the possibility of different impacts from the operation of a storage resource. The study also assesses what specific operational characteristics of the storage resource may be necessary in specific operational situations. If the storage resource has the potential to provide grid level services at a location valuable to the bulk energy system, but the distribution infrastructure is unable to

[91] For example, power flow studies typically focus on particular seasonal conditions such as peak summer conditions or a winter dispatch.

accommodate the resource reliably, this may have market implications at the bulk energy system level if the operator is forced to procure that service elsewhere. Accurate studies during the interconnection process could help to identify and mitigate such concerns.

4.4.2 Assumptions and Data

This study continues to use the Feeder J1 model, as previously described. Staff analyzed two applications of energy storage: (1) using energy storage for frequency regulation services and (2) using energy storage for load leveling.

In each case, staff added one energy storage device to the model. Adding a single energy storage system instead of several distributed units does not significantly change the results from the transmission operator standpoint because transmission system operators only see the impact of aggregated energy storage, such as a change in substation power flows and voltages. The difference in the results is mostly due to different patterns of distribution system losses.

In order to compare the impact of similar size aggregated DERs with different applications, staff selected the energy storage size (1.7 MW and energy of 6.8 MWh) based on the installed capacity of the existing solar PVs. The location of the largest solar PV units was selected as the energy storage system location. To model the operation (charging and discharging intervals) of the energy storage system for the regulation service, staff used one day of PJM RegD[92] (a fast regulation signal that is sent every two seconds to the devices participating in regulation service).

For the load leveling application, staff developed a 24-hour charging/discharging energy storage profile such that the energy storage system charges during the night and discharges during the day.[93] Since the efficiency of an energy storage system is not 100 percent, the amount of energy charged is larger than energy discharged.

4.4.3 Methodology

Staff added one energy storage system to the detailed feeder model. For the frequency regulation application, staff performed a time series analysis over a 24-hour

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[92] *See Ancillary Services: Market-Based Regulation - RTO Regulation Signal Data*, PJM, *available at* http://www.pjm.com/markets-and-operations/ancillary-services.aspx.

[93] *See Energy Storage Projects in AEP*, Ali Nourai, page 7, (October 2009), *available at https://energy.gov/sites/prod/files/ESS%202009%20Peer%20Review%20-%20Energy%20Storage%20Projects%20in%20AEP%20-%20Ali%20Nourai%2C%20AEP.pdf.*

period with a two-second time step in order to simulate the frequency of the regulation signal. For the load leveling application, staff ran the time series analysis over a 24-hour period with a 15-minute time step. To focus only on the impact of energy storage, the model disconnected existing solar PV units from the system. Staff assessed changes in the real and reactive power in the substation and changes in voltage on the high voltage side of the substation transformer.

4.4.4 Results

When an energy storage system is used to provide frequency regulation service, peak demand on the affected feeder may increase if the charging of the energy storage system is coincident with the occurrence of the feeder peak load. If this happens, the increase in the peak load on that affected feeder may be larger than the installed storage capacity (in MW) because of the increase in the feeder power losses. Since the regulation signal is volatile with very frequent changes, the probability that this may happen is high. Energy storage is a very specific technology because it can consume and generate power, meaning that it may increase or decrease the feeder loading.

Figure 16: Substation Real Power

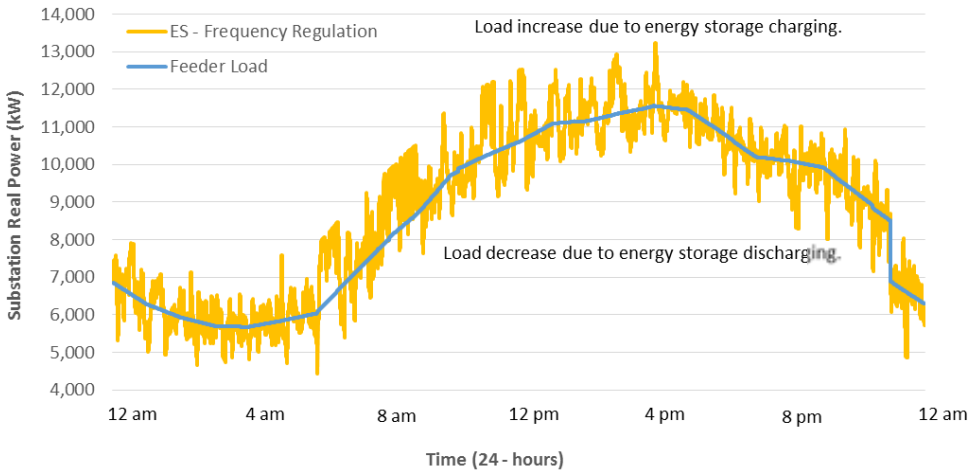


Figure 16 illustrates substation real power as seen by the transmission operator during a 24-hour period. The feeder peak demand increased from 11,558 kW to 13,241 kW. The substation load change ranged from a 30 percent decrease to a 27 percent increase compared to the substation load without the storage. Hence, additional load on the feeder due to the operation of the storage system may reduce the overall available supply from resources on the feeder. If a DER owner is planning to participate in the ancillary services market, the distribution system operator may want to be informed because the distribution feeder elements are sized based on the estimated peak demand, and any additional loading can cause an overloading of the lines. In addition to changes in the substation/feeder load, using an energy storage system located on a distribution system for regulation service will cause sudden changes in the voltage and potential

issues with power quality. Some of these effects may also impact the transmission system.

Figure 17: Substation Voltages - Phase A

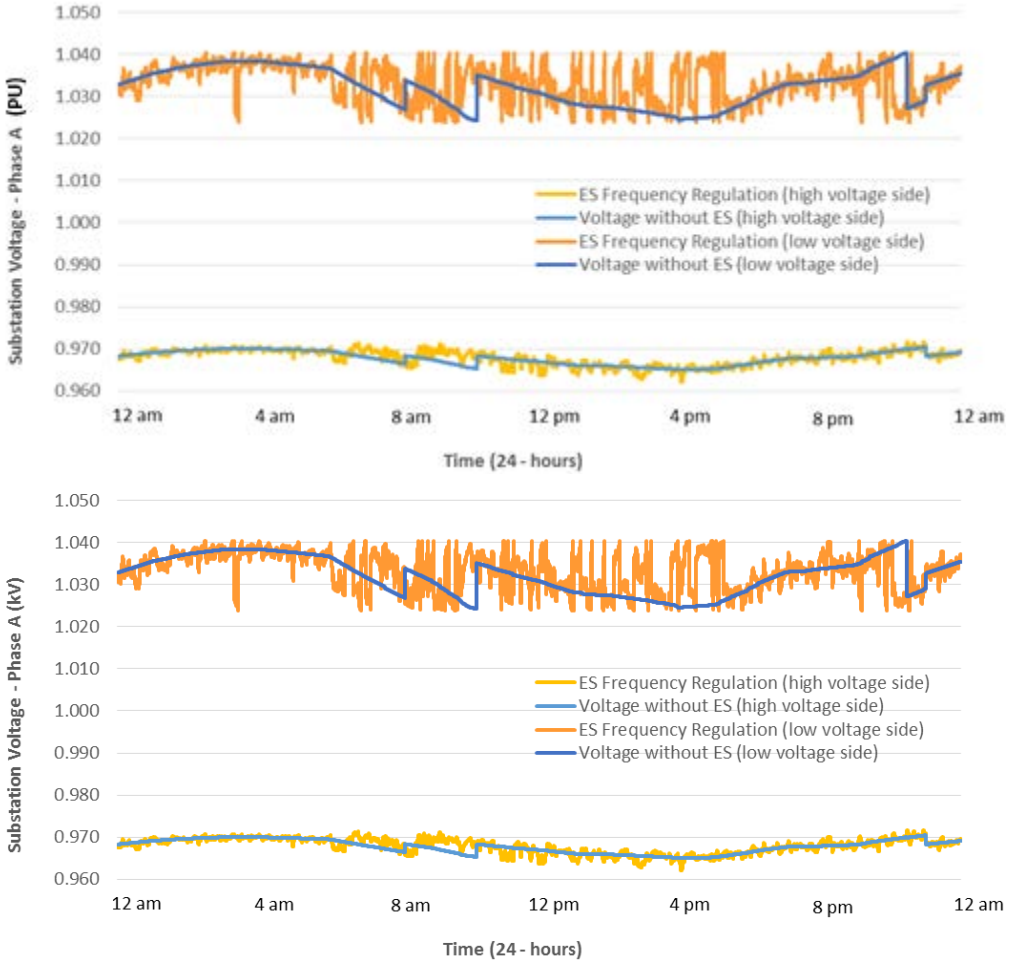


Figure 17 illustrates the substation voltage (light blue and yellow lines), the feeder voltage (dark blue and orange lines), and the frequent changes caused by the energy storage system. In the given example, the change on the high voltage side of the substation transformer ranges from a 0.4 percent decrease to a 0.3 percent increase compared to the voltage without energy storage, which ranges from a 1.6 percent decrease to a 1.5 percent decrease on the low voltage side. Depending on the energy storage system power capacity (in MW) participating in the market, these changes can be higher or lower.

In the case of load leveling, the changes introduced are much smoother. Figure 18 illustrates substation real power over 24 hours. Since the energy storage system is charging during the night, off-peak load increases, and since the energy storage system is discharging during the peak time, the peak load is reduced. The energy storage system,

charges/discharges with constant power. This profile can be changed based on the feeder/substation load profile. Voltage changes (Figure 19) are also much smoother because there is no sudden change in the load.

Figure 18: Substation Real Power – Load Leveling

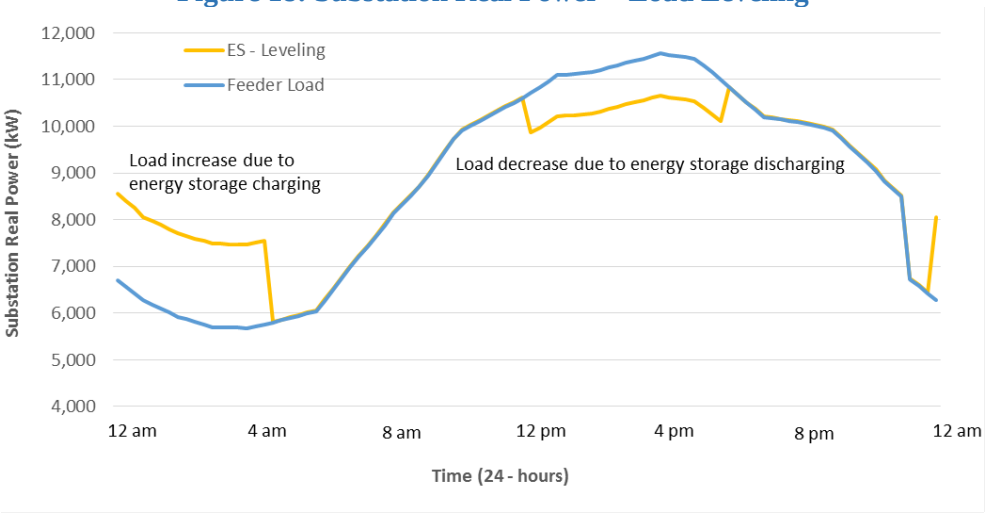
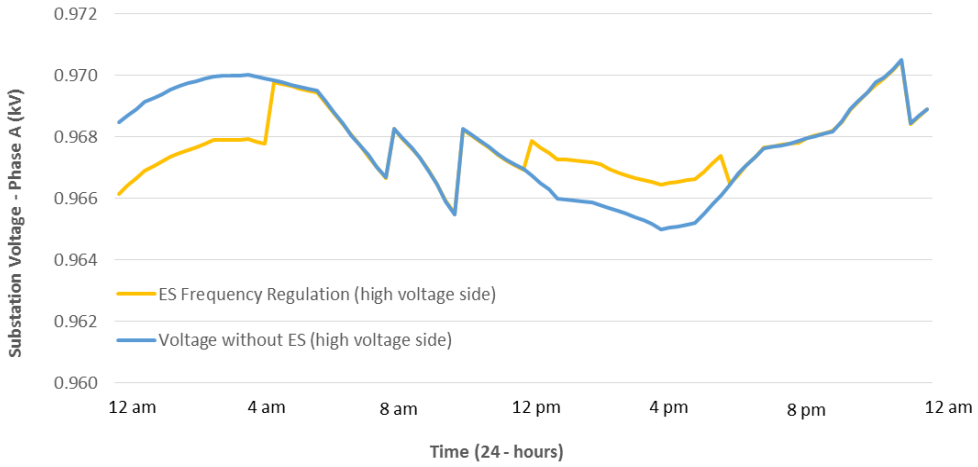


Figure 19: Substation Voltage – Phase A – Load Leveling



As demonstrated above, when DER resources provide services such as frequency regulation, and if the distribution infrastructure is unable to accommodate this type of operation, there could be potential market and reliability impacts. This potential impact to reliable operation of the distribution system infrastructure could affect distribution resources participating in wholesale markets by providing energy, capacity or ancillary services if these services cannot be provided with a reasonable assurance of expected performance. The distribution system operator may need to be allowed to assess the impact on its system of the participation of energy storage systems or any other DERs in wholesale markets, and may need to provide feedback on upgrades to the infrastructure necessary to support this wholesale participation. The distribution provider may also be

able to provide recommendations on the resource size (in MW) during the installation process so that the reliability of the distribution system remains intact.

4.5 Assessing the Benefit of Smart Inverters to Reliability (Distribution Modeling)

This study assesses whether smart inverters on the distribution system provide greater benefits than regular inverters used in some DER installations. Smart inverters have controls that provide additional capabilities, such as allowing DERs to provide voltage and frequency control. This study examines the potential impacts of smart inverters providing volt-VAR control; it does not include frequency control.

4.5.1 Study Purpose

The smart inverter study assesses whether smart inverters on the distribution system provide significant benefits compared to regular rooftop solar inverters. Smart inverters have the potential not only to provide real power, but also to assist in providing reactive power and voltage regulation, which increases the number of PVs that can be installed reliably on a distribution feeder. Therefore, smart inverters may be able to address some of the operational issues associated with increased DER penetration. The study assesses their impact on reliability using line loading, voltages, and voltage control equipment. It focuses primarily on the distribution system, and also explores the potential for a transfer of benefits to the transmission system.

4.5.2 Assumptions and Data

Staff used Feeder J1 for the simulation and analysis. All existing solar PVs were equipped with smart inverters that could provide volt-VAR control. The volt-VAR control function allows each individual solar PV system to provide a unique VAR response according to the voltage at the point of connection (0.416 kV and 0.24 kV). All the solar PVs were set to use the same volt-VAR curve such that the inverter provided the maximum possible reactive power if the voltages were smaller or larger than 0.95 and 1.05, respectively, and slightly less if the voltage was within that range. Staff conducted a time series analysis on a 30-minute interval.

4.5.3 Methodology

To examine the impact of smart inverters, staff modeled two cases with rooftop solar installations: (1) one with regular inverters and (2) one with smart inverters. The impact on reliability was assessed by monitoring variability in line loading, voltages, and voltage control equipment operation. While this study focused primarily on the distribution system, it also reviewed the data to determine whether benefits can be

transferred to the transmission system by analyzing voltages and real and reactive power at the transmission-distribution interconnection point.

4.5.4 Results

EPRI previously showed that using smart inverters can increase the amount of solar PVs that can be reliably installed on the feeder (i.e., increase the hosting capacity of the feeder)[94] and can potentially lead to higher penetration levels of PV DERs in the future. Adding smart inverters with volt-VAR control capability to the PV installations improved the reactive power and voltage at the local and substation level in this analysis. Based on the volt-VAR curve, the maximum voltage at the PV interconnection point was reduced from 1.032 down to about 1.025 pu (as shown in Figure 20) by absorption of VARs from the grid (as shown in Figure 21) following the volt-VAR curve and control algorithm. Voltage levels at the substation also dropped but by a much smaller amount (about 0.2 percent).

[94] *See Distributed PV Monitoring and Feeder Analysis – Hosting Capacity Method*, EPRI, *available at* http://dpv.epri.com/hosting_capacity_method.html.

Figure 20: Voltage at PV location and at Substation – Phase A

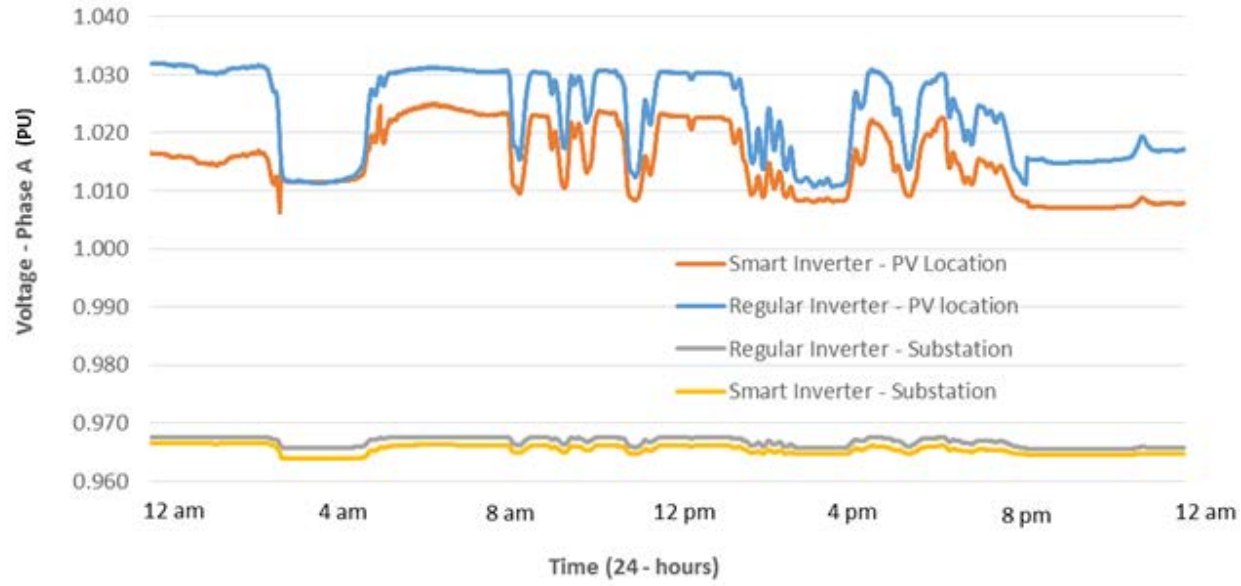
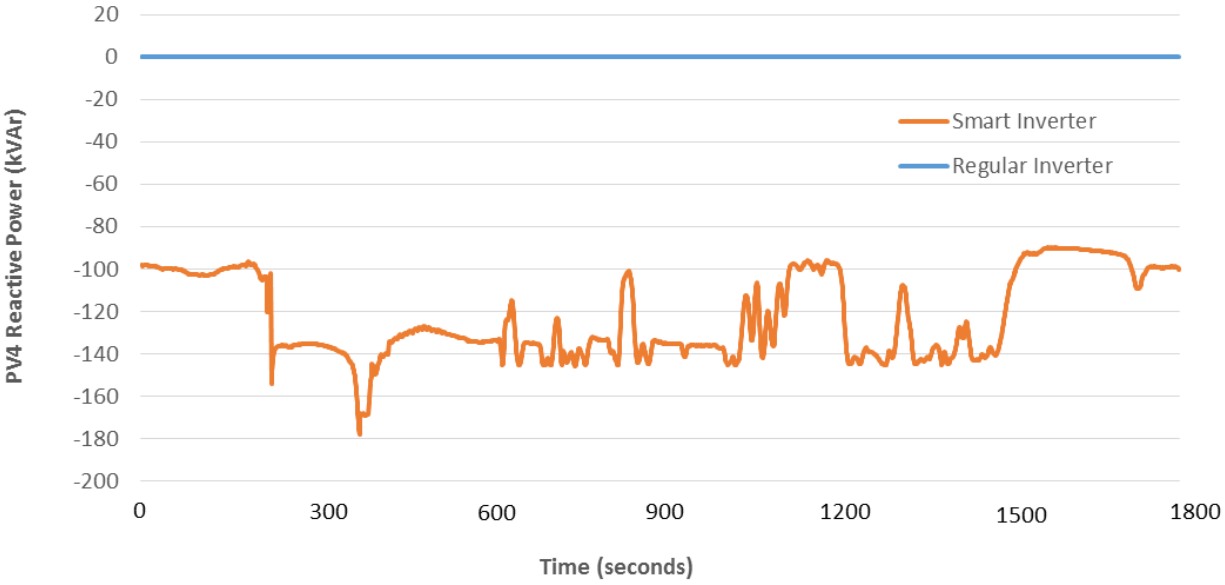


Figure 21: PV Generation of Reactive Power with and without Smart Inverter



This case illustrates a situation in which the local and substation voltage controls have opposite objectives. If the local voltage were 1.03 pu, the objective would be to bring this voltage closer to 1.0 pu or below so that additional PVs could be installed on the feeder. In contrast, if the substation voltage level were about 0.965 pu, the objective

would be to increase it. However, by decreasing the local voltage, the substation voltage decreases as well.

If solar PV with smart inverters were used to support voltage at the substation level, this control would need to be coordinated between the market operator, the transmission system operator and the distribution system operator. Similarly, as in the energy storage system analysis, smart inverters may be used to support the operation of the transmission power system. However, use of smart inverters to support the operation of the transmission system without consideration of distribution system requirements would be unwise because the operation of PVs or any other DER technology with a smart inverter could impact distribution system reliability or power quality.

5. Conclusions

As demonstrated by this technical assessment, given the growing adoption of DERs in the United States, there are a number of key bulk power system reliability topics to explore, including:

- The impact of the current common industry modeling practice of netting DERs with load, which may mask the effects of DER operation;
- DER capabilities for voltage and frequency ride through during contingencies;
- The potential for improved voltages due to the unloading of the bulk power system associated with the location of DERs at or near customer loads;
- Potential effects upon system-wide transmission line flows and generation dispatch due to changing load patterns; \
- The sensitivity of voltage or power needs to different types of DER applications (i.e., providing energy, capacity, or ancillary services); and
- The need to develop planning processes that capture more detailed models of DERs and allow for modeling of the interface between the transmission and distribution systems to enable information exchange and more accurate calculations of the DER impact on the bulk power system.
- The advantages and disadvantages of allowing DERs to participate directly in the organized wholesale electric markets.

Further discussion also is needed on potential means to improve modeling practices with respect to DERs, including options for improving available data and the incorporation of detailed DER models into existing industry models. In addition, further dialogue is needed to identify other areas for additional analysis, such as additional study types and sensitivities which could provide further insight into the potential local and system-wide impacts of future growth in DER capacity. Efforts such as these could help track and assess the impact of changing conditions on the bulk power system to identify emerging trends and address potential future reliability challenges.

Northeast Power Coordinating Council, Inc.

Regional Standards Committee

Blockchain, Batteries, and Microgrids

Guy V. Zito

NPCC AVP - Standards

Blockchain in Energy Transactions

- Released in 2009-first used in Bitcoin digital cryptocurrency
- No centralized database, relies on user "nodes"-distributed ledger-peer to peer
- Each Block contains data, an address, and an address of the previous block
- All user nodes see the block and associated transactions
- Very difficult to hack-if a Block is compromised it is dismissed by the collective user nodes

Battery Technology-Distributed Energy Storage (DES)

- Distribution level and behind the meter (Tesla power wall)
- Dispatchable- CALISO actively dispatching batteries up to 5 MW
- Hawaii contracting for a 13 MW battery storage project on a solar farm on the transmission system
- Allows better integration of solar and wind
- Reduces the need for energy dumping when DER overproduces

Microgrids

A group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode.

- Generation/resource
- Storage devices
- Controllable loads
- Delivery system

A Microgrid Energy Market

Brooklyn Microgrid (LO3 and Siemens)

- User driven decentralized energy system-5 sq. blocks in Brooklyn
- Blockchain-based local energy trading sellers and buyers
- Works in tandem with the grid
- Secure transactions and creates a business based on energy sharing would allow participants to bypass the electric company
- Could eventually replace the need for a grid
- Meters measure supply and demand but also communicate with each other and form the blockchain

Microgrid Operational Challenges

- EMS architecture needs to accommodate vast interactive information exchanges from different layers
- The increased penetration of DER could cause steady state and transient over or under-voltages at the point of connection, protection malfunctions, increase in short circuit levels and power quality problems
- Increase in complexity of control and protection systems will be required, also changes to existing directional based protection systems
- Voltage and frequency control during Microgrid islanding
- Reliable island operation with only DER requires power controllers with special characteristics regarding droop

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

Questions or Comments ?

Northeast Power Coordinating Council, Inc.

Regional Standards Committee

Distributed Energy Resources FERC Staff Report

Guy V. Zito

NPCC AVP - Standards

Report suggests DER capacity, if not properly accounted for, could cause reliability concerns for the bulk power system. Specifically:

- The impact of the current common industry modeling practice of netting DERs with load, which may mask the effects of DER operation;

- DER capabilities for voltage and frequency ride through during contingencies;

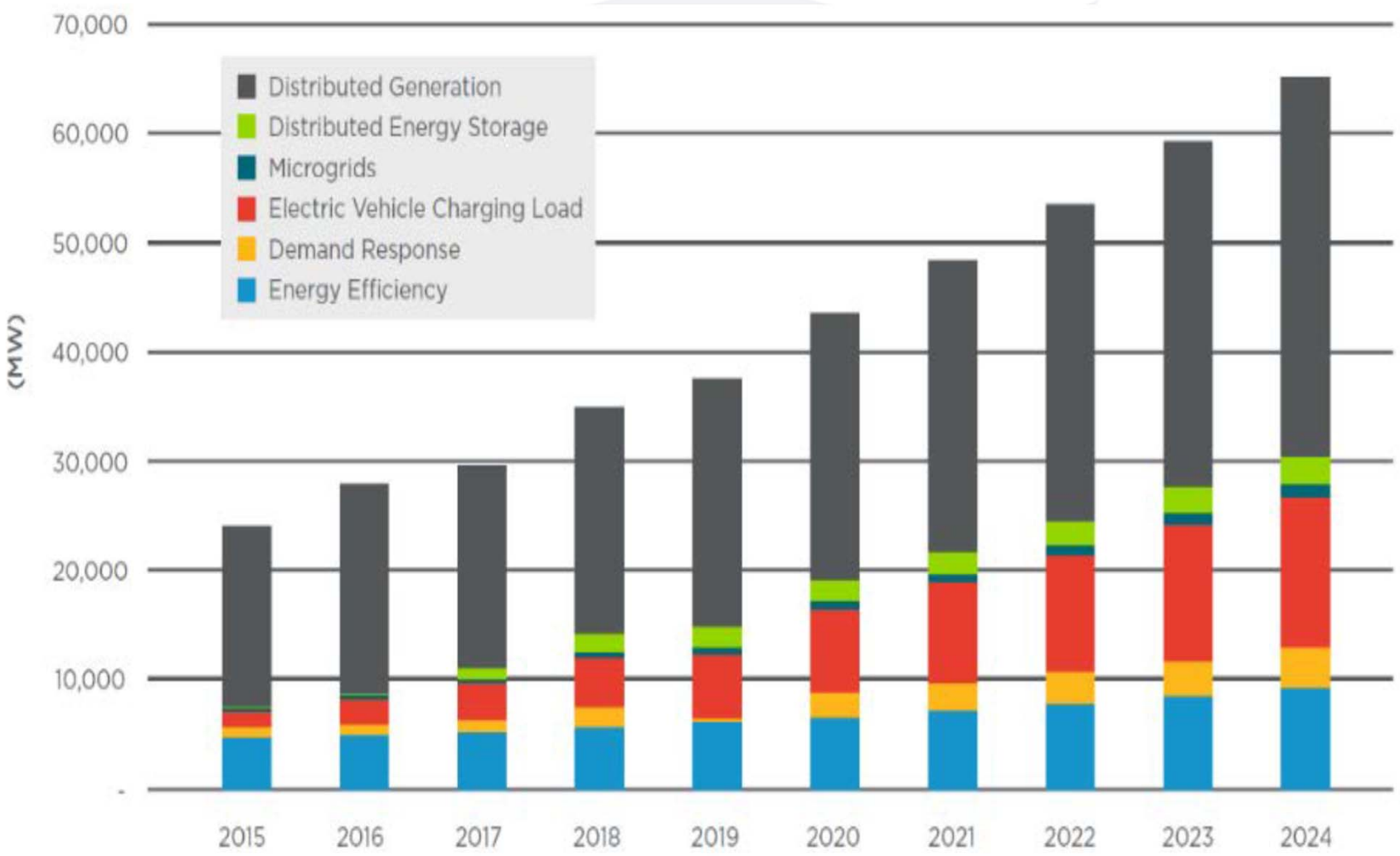
- The potential for improved customer-level voltages due to the unloading of the bulk power system associated with the location of DERs at or near customer loads;

- Potential effects on system-wide transmission line flows and generation dispatch due to changing load patterns; and

- The sensitivity of voltage or power needs to different types of DER applications (i.e., the provision of energy, capacity, or ancillary services).

DER PV installations account for 12 % of new capacity. California (7000 today) DER interation target of 12,000 MW by 2020.

NPCC US installed capacities from EIA NY-1305 MW, CT 410 MW, MA 1477 MW, ME VT and NH less than 250MW each.



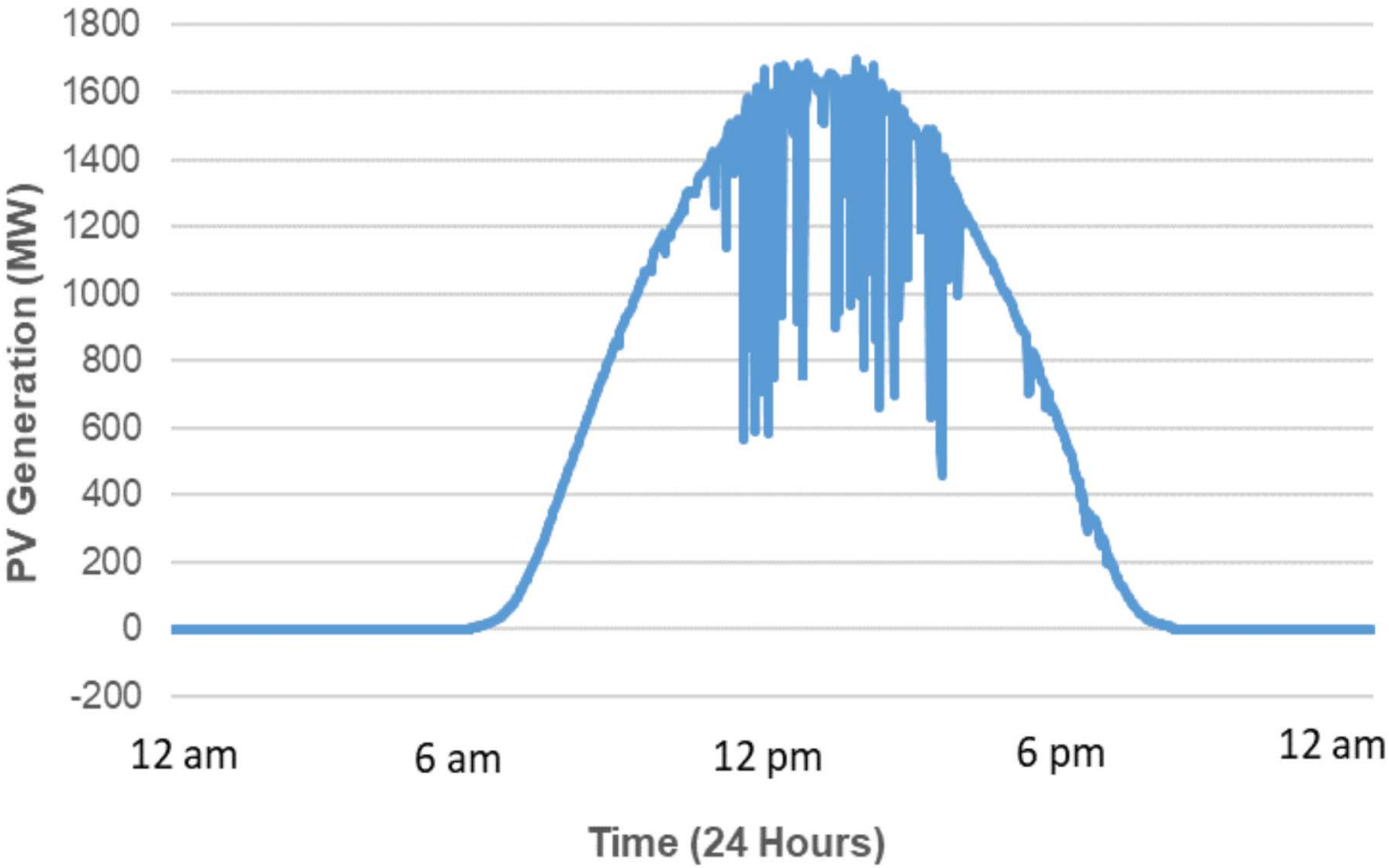
US Totals and Projections (Navigant)

Potential reliability issues which may arise from increased DER penetration:

- Lack of DER data and effect on operation, planning, and design of the BPS (basic data - location, size, and technological capabilities-no process in place to provide static DER data to bulk system operators and planners-lack of telemetry for real-time operations-statistical derivation? Cost issue);
- The need for coordination between the settings and capabilities of resources connected to the bulk power system and DERs;
- The need for improved modeling practices and capabilities for DERs;
- The effect of DER daily generation profiles on system unit commitment and ramping needs (CAISO reports cloud cover causes intermittent PV production and significantly increases the need for ramping) ; and
- The effect of distribution connected variable PV and wind output on day-ahead load forecasts.

NPCC, Inc.

EPRI one-minute PV Generation on a cloudy day (CAISO)



Actions taken to address reliability issues with DER penetration:

- SGIA revision- Order 828 Voltage and frequency ride through on units smaller than 20 MW connected to Commission jurisdiction facilities
- IEEE 1547 revision, DER resources, going forward, to have ride through capabilities rather than tripping off-line, standardize communication interfaces, protocols and information models
- Concept of Distribution System Operator (DSO) -intermediate entity between the RTO/ISO and DER -The DSO could be the medium by which RTOs/ISOs are provided with, visibility of DER, net load forecast and dispatchable DER products schedules and bids, metering, and telemetry.
- Reforming the Energy Vision (REV) initiative- the New York PSC has implemented changes through a series of orders to the structure of its electric system, including the development of distribution system platform (DSP) providers, and has required distribution utilities in the state to file distribution system implementation plans and develop a comprehensive set of functional requirements for a next-generation distribution system platform to enable participation of DERs in the provision of electricity services.

NPCC, Inc.

Key bulk power system reliability topics to explore, including:

- The impact of the current common industry modeling practice of netting DERs with load, which may mask the effects of DER operation;
- DER capabilities for voltage and frequency ride through during contingencies;
- The potential for improved voltages due to the unloading of the bulk power system associated with the location of DERs at or near customer loads;
- Potential effects upon system-wide transmission line flows and generation dispatch due to changing load patterns;
- The sensitivity of voltage or power needs to different types of DER applications (i.e., providing energy, capacity, or ancillary services); and
- The need to develop planning processes that capture more detailed models of DERs and allow for modeling of the interface between the transmission and distribution systems to enable information exchange and more accurate calculations of the DER impact on the bulk power system.
- The advantages and disadvantages of allowing DERs to participate directly in the organized wholesale electric markets.

Potential NPCC Opportunities:

- Improve modeling practices with respect to DERs
- Create options for improving availability of data and the incorporation of detailed DER models into existing industry models.
- Identify other areas for additional analysis, such as additional study types and sensitivities which could provide further insight into the potential local and system-wide impacts of future growth in DER capacity
- Identify opportunities to improve visibility of DER
- Identify coordination issues between protective systems
- Create miminum region wide requirements for DER Distribution level interconnections
- Identify and improve real-time forecasting and coordination with operations
- Other? Initiate standards, Directory changes or additions, guidelines, or whitepapers?

NPCC, Inc.

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

Questions or Comments ?

NORTHEAST POWER COORDINATING COUNCIL, INC.
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NPCC 2018 Corporate Goals

Approved by the NPCC Board at its January 31, 2018 Meeting

On November 9, 2017 the NERC Board of Trustees approved an ERO Enterprise Operating Plan that identifies the ERO Enterprise's vision, mission, core principals, and goals, and provides a list of key contributing activities by the combined ERO Enterprise, NERC, and the Regional Entities as applicable to inform a rolling three-year operational planning horizon. The Operating Plan has six goals, each of which is supported by the combined ERO Enterprise, NERC, and the Regional Entities, as applicable. The majority of ERO Enterprise resources and activities, in support of these goals, focus on preserving and building on current achievements toward establishing risk-based controls to minimize BPS reliability risk while also driving enterprise-wide operational efficiency and effectiveness. Remaining ERO Enterprise activities and resources focus on identifying, evaluating, and addressing new and emerging issues affecting BPS reliability and security and improving communication strategies, knowledge transfer, and engagement with stakeholders across North America.

Each of the NPCC 2018 Corporate Goals is presented in terms of support of specific ERO goals, identified in the Operating Plan, to demonstrate complementary alignment. The NPCC 2018 goals are an expansion of the multitude of objectives outlined in the 2018 NPCC Business Plan and Budget, which was approved by the NPCC Board on June 28, 2017 and by FERC on November 1, 2017. The Operating Plan goal addressing effective and efficient operations is a core requirement of NPCC management, and as such is not identified as a separate corporate goal. For NPCC Goals, Threshold, Target and Stretch performance levels are identified. Attainment of a previous performance level is a pre-requisite for credit of attainment at a higher performance level. In addition, each aspect of a goal has been classified as either Qualitative or Qualitative and Quantitative, and a third-party reviewer has been identified to support objectivity and enhance auditability.

A summary of the 2018 Corporate Goals appears on the next page, with the full set of supporting milestones for the 2018 Corporate Goals included on the subsequent pages.

NPCC 2018 CORPORATE GOALS

Goal	*Goal Objectives*	*Qualitative*	*Qualitative and Quantitative*	*Oversight Reviewer*
I - (25%)	**Goal Objective: Risk Responsive Reliability Standards** *Conduct a strategic review of the need for NPCC Criteria, and determine a potential Regional approach to developing reliability guidance for distribution level Distributed Energy Resources (DER) that could impact Bulk Electric System reliability.*		***X***	***Reliability Coordinating Committee and Regional Standards Committee***
II - (20%)	**Goal Objective: Objective and Risk Informed Compliance Monitoring, Mitigation, Enforcement, and Entity Registration** *Identify, analyze, and communicate the degree of risk associated with non-compliance trends in order to assist registered entities in future compliance and to support the continuing culture of high reliability in Northeastern North America.*	***X***		***Compliance Committee***
III - (15%)	**Goal Objective: Reduction of Known Risks to Reliability** *Reduce identified reliability risks due to protection system misoperations, event severity, and lack of accurate DER models.*		***X***	***Reliability Coordinating Committee***
IV- (25%)	**Goal Objective: Identification and Assessment of Emerging Reliability Risks** *Identify and assess reliability risks to resource adequacy due to accelerated retirement of traditional resources, severe disruptions on the natural gas system, and correlation of DER with load.*		***X***	***Reliability Coordinating Committee***
V - (15%)	**Goal Objective: Identification and Reduction of Cyber and Physical Security Risks** *Conduct physical and cyber security outreach and internal control evaluations to collaboratively and pre-emptively educate NPCC stakeholders on the changing threat landscape associated with cyber and physical security.*		***X***	***Compliance Committee***

NPCC 2018 CORPORATE GOALS

I	**Risk- Responsive Reliability Standards** ***In support of ERO Enterprise Strategic Plan: Goal 1***	**Weighting:** **25% of Total**		
	Conduct a strategic review of the need for NPCC Criteria, and determine a potential Regional approach to developing reliability guidance for distribution level Distributed Energy Resources that could impact Bulk Electric System reliability.	**Threshold**	**Target**	**Stretch**
I-1. (15%)	Conduct a strategic review of the need for NPCC's Regionally specific, more-stringent reliability Criteria. The evaluation will identify the overarching reliability benefits and recommendation on whether NPCC should retain the Criteria within topic areas, such as operations, planning, protection, etc.	Develop an action plan for the strategic review of the need for NPCC Criteria and submit to TFCP for consideration by their 3/18 Meeting. Provide status update to Board.	Submit report on strategic review of the need for NPCC Criteria to the Task Forces for comment by 11/18 Meetings. Provide status update to Board.	Submit report on strategic review of the need for NPCC Criteria to RSC and RCC for consideration by 12/18 Meeting. Provide status update to Board.
I-2. (10%)	Determine a potential Regional approach to developing reliability guidance for distribution level Distributed Energy Resources (DERs) that could impact Bulk Electric System (BES) reliability.	Develop potential approach to address reliability related impacts on the BES from distribution level DERs and gain RSC concurrence by 11/18 Meeting.	Provide Regional input on all standards under development, as well as the "Standards Efficiency Review" project, and any revised IEEE standard on DERs by RSC 12/18 Meeting.	Revise PRC-006-NPCC-2 "*Automatic Underfrequency Load Shedding*" Regional Standard, considering DER increases, and post for industry ballot by 12/31/18.

NPCC 2018 CORPORATE GOALS

II	**Objective, Risk-Informed Compliance Monitoring, Mitigation, Enforcement, and Entity Registration** ***In support of ERO Enterprise Strategic Plan: Goal 2***	**Weighting: 20% of total**		
	Identify, analyze, and communicate the degree of risk associated with non-compliance trends in order to assist registered entities in future compliance and to support the continuing culture of high reliability in Northeastern North America.	**Threshold**	**Target**	**Stretch**
	Reduction of Bulk Electric System Risk Due to Non-Compliance with Operation & Planning and CIP Standards	Identify better practice elements for audit preparation. Perform outreach webinar to mentor entities by 3/18. Identify the relationship of the key reliability tasks and key standard requirements by function. Mentor on better practices to establish internal controls that are fully implemented. Conduct webinar by 4/18.	Identify and analyze the NPCC and NERC most violated standards since 2016 that caused a serious or substantial risk to the Bulk Power System. Present risk analysis to CC by 9/18 Meeting. Establish a CC Working Group to identify necessary actions for a control to be considered fully implemented. Present at Fall 2018 Workshop.	Identify better practices to provide reasonable assurance of CIP compliance. Conduct webinars by 6/18 and by 11/18. Present results to CC by 12/18 Meeting. Perform mitigation analysis of serious NPCC violations and serious ERO violations. Conduct webinar on risk and mitigation analysis by 12/18.

NPCC 2018 CORPORATE GOALS

III	**Reduction of Known Risks to Reliability** ***In support of ERO Enterprise Strategic Plan: Goal 3***	**Weighting; 15% of Total**		
	Reduce identified reliability risks due to protection system misoperations, event severity, and lack of accurate DER models.	**Threshold**	**Target**	**Stretch**
III-1. (5%)	Development of Composite Protection System Misoperation Metric - The metric, developed through the SP-7 Working Group, is intended to include addressing "Unknown" protection system misoperations and other causes in order to foster high reliability by encouraging industry to improve their score/performance over time.	Develop an NPCC composite misoperation metric to support risk identification and mitigation and report status to the RCC at 5/30/18 meeting.	Obtain TFSP's endorsement of the proposed NPCC composite misoperation metric and report status to RCC at 9/5/18 meeting.	Present and obtain RCC approval for implementation of proposed NPCC composite misoperation metric at 12/4/18 RCC meeting.
III-2. (5%)	Event Severity - Analyze system events to identify risks, mitigation strategies, and lessons learned. Perform a comparison and trending analysis to develop a potential metric to gauge relative risk of the events trending year-to-year.	Perform an assessment and trend analysis of all ERO-wide 2015 and 2016 events and report at the 5/30/18 RCC meeting.	Perform additional assessments and trend analyses of all NPCC 2017 and report at the 9/5/18 RCC meeting.	Update assessments for 2018 events (received as of the end of the 3rd quarter of 2018) and report at 12/4/18 RCC meeting.
III-3. (5%)	Develop and Maintain Accurate DER Models - Promote and assist in the development of guidelines and practices to address Distributed Energy Resources (DERs) in planning models. This includes an examination of if and how distribution DER is modeled on the BES.	Identify current practices for incorporation of installed DERs in planning practices and report at the 5/30/18 RCC meeting.	Develop a scope to create guidelines for incorporating DERs into planning studies and present for RCC approval at the 9/5/18 meeting.	Report on the development of guidelines for incorporating DERs into planning studies to the RCC at the 12/4/18 meeting.

NPCC 2018 CORPORATE GOALS

IV.	**Identification and Assessment of Emerging Risks to Reliability** ***In support of ERO Enterprise Strategic Plan: Goal 4***	**Weighting; 25% of Total**		
	Identify and assess reliability risks to resource adequacy due to accelerated retirement of traditional resources, severe disruptions on the natural gas system, and correlation of DER with load.	**Threshold**	**Target**	**Stretch**
IV-1. (5%)	Assess the risks to resource adequacy due to accelerated retirement of conventional NPCC resources replaced with distributed energy resources on the system over the next ten years.	Develop the scope for an evaluation of the impact on resource adequacy of accelerated retirements of generation and report to the RCC at the 2/28/18 meeting.	Present preliminary results of the evaluation to the RCC at the 9/5/18 meeting.	Report completed evaluation results to the RCC at the 12/4/18 meeting.
IV-2. (10%)	Conduct a detailed assessment using a power system simulator to confirm NERC's screening analysis of a generation cluster within NPCC that may create reliability risks under significant loss of natural gas infrastructure, and make recommendations on mitigation if any reliability issues are identified.	Develop the Scope of Work for the assessment – report to the RCC at the 2/28/18 meeting.	Present preliminary results of the assessment to the RCC at the 9/5/18 meeting.	Report completed assessment results to RCC at the 12/4/18 meeting.
IV-3. (10%)	Develop NPCC area probabilistic models for wind and behind the meter (solar) resources based on their past performance, in order to perform a peak load correlation analysis using the @Risk program. Evaluate the significance of the amounts of NPCC wind and BTH solar resources for resource planning and operating models.	Develop the Scope of Work for the study– report to the RCC at the 2/28/18 meeting.	Present preliminary results of the study to the RCC at the 9/5/18 meeting.	Report completed study results to the RCC at the 12/4/18 meeting.

NPCC 2018 CORPORATE GOALS

V.	**Identification and Reduction of Cyber and Physical Security Risks** ***In support of ERO Enterprise Strategic Plan: Goal 5***	**Weighting; 15% of Total**		
	Conduct physical and cyber security outreach and internal control evaluations to collaboratively and pre-emptively educate NPCC stakeholders on the changing threat landscape associated with cyber and physical security.	**Threshold**	**Target**	**Stretch**
		Perform physical and cyber security outreach assessments on 3 entities by 8/18. Summarize the 2017 FERC report on observance of CIP v5 audits and present to CC at the 3/18 meeting.	Present information on significant cyber and physical security risks via webinar by 8/18, to the CC by 9/18, and at Fall 2018 Workshop. Analyze threats identified in the 2017 FERC report on observances of CIP V5 audits, and conduct outreach webinar by 6/18.	NPCC to perform physical and cyber security outreach assessments on 3 additional entities by 12/18. Perform 4 CIP Internal Controls Evaluations by 12/18 CC meeting.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	**)** **)** **)**	**Docket No. AD18-7-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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May 9, 2018

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	**)** **)** **)**	**Docket No. AD18-7-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

On January 8, 2018, the Federal Energy Regulatory Commission (the "Commission") initiated a new proceeding to evaluate resilience of the bulk-power system ("BPS") in regions operated by regional transmission organizations and independent system operators (together, "RTOs").[1] Specifically, the Commission seeks to: (1) develop a common understanding of the term resilience; (2) understand how RTOs assess resilience; and (3) evaluate whether additional Commission action is appropriate.[2] While initially soliciting comments from RTOs, the Commission acknowledged that, "NERC and the regional entities tasked with implementation of mandatory reliability standards have a critical role to play in this area…. we will provide interested entities an opportunity to submit reply comments….."[3]

As the Commission certified Electric Reliability Organization ("ERO"),[4] the North American Electric Reliability Corporation ("NERC") must develop and enforce Reliability Standards that provide an adequate level of reliability for Reliable Operation of the BPS and must assess the reliability and adequacy of the BPS.[5] As discussed herein, resilience is a

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1 *Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,012 (2018) ("Order").

2 *Id.* at P 18.

3 *Id.* at P 19.

4 *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) ("Certification Order").

5 As defined in section 215 of the Federal Power Act ("FPA"). 16 USC 824o.

component of reliability in relation to an event and thus an implicit feature of NERC's activities. NERC hereby submits reply comments in this proceeding to summarize the manner in which resilience is a component of reliability, to highlight NERC Reliability Standards and other activities that support resilience, and to underscore the importance of reexamining resilience in light of the changing generation resource mix and evolving cyber and physical threats.[6]

I. COMMUNICATIONS

Notices and communications with respect to these comments may be addressed to the following:[7]

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[6] RTO comments were filed on March 9, 2018 by: Midcontinent Independent System Operator, Inc. ("MISO"), ISO New England Inc. ("ISO-NE"), Electric Reliability Council of Texas, Inc. ("ERCOT") and the Public Utility Commission of Texas ("PUCT"), Southwest Power Pool, Inc. ("SPP"), New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), and the California Independent System Operator Corporation ("CAISO").

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

II. EXECUTIVE SUMMARY

Reliability of the BPS requires the resilience to anticipate, withstand, recover, and adapt to events on the system. In accordance with section 215 of the FPA and Commission directive in the Certification Order, reliability encompasses aspects of resilience of the BPS. As discussed in these comments, NERC has defined the adequate level of reliability or "ALR" to include resilience as a time-based component of reliability. *See infra* Section III.A.

As recognized in RTO comments, NERC activities already address several aspects of resilience, including robustness, resourcefulness, rapid recovery, and adaptability of the grid. At the direction of the NERC Board of Trustees ("Board"), the Reliability Issues Steering Committee ("RISC") has also proposed a resilience framework to reexamine resilience and whether NERC should take additional action. The RISC resilience framework is based on the ALR and the National Infrastructure Advisory Council ("NIAC") Framework for Establishing Critical Infrastructure Goals (relied upon by the Commission for its proposed definition of resilience).[8] NERC will continue to assess whether further activities are appropriate to support a resilient grid, consistent with the overarching scope of ALR, the RISC resilience framework, and any applicable Commission orders. *See infra*, Section III.B.

NERC supports the Commission's renewed dialogue around resilience. The changing resource mix demands reevaluation of resilience and consideration of policies recognizing essential reliability services ("ERS") and the value of a balanced portfolio of generation and infrastructure that provide fuel assurance, particularly under extreme weather conditions. As detailed in prior NERC comments and reflected in RTO comments, the changing resource mix

[8] A Framework for Establishing Critical Infrastructure Resilience Goals, National Infrastructure Advisory Council (October 19, 2010), *available at*, https://www.dhs.gov/xlibrary/assets/niac/niac-a-framework-for-establishing-critical-infrastructure-resilience-goals-2010-10-19.pdf.

has implications for reliability. In addition, evolving cyber and physical threats aimed at critical energy infrastructure may challenge resilience in the future. These reliability implications support policies recognizing the value of ERS and a diverse energy portfolio with sufficient fuel assurance to promote resilience. Policies supporting ERS, fuel assurance, and security as key elements of resilience would help ensure that the BPS continues to evolve in a manner that supports Reliable Operation of a resilient grid. *See infra* Section III.C.

III. COMMENTS

A. Resilience is an Element of Reliable Operation of the BPS.

Pursuant to section 215 of the FPA, NERC develops Reliability Standards based on what is necessary to achieve an adequate level of reliability for Reliable Operation of the BPS.[9] NERC must also conduct Reliability Assessments that evaluate BPS performance and identify emerging risks to reliability. Reliable Operation of the BPS includes the ability to withstand probable contingencies and the ability to manage adverse reliability impacts of disturbances in a coordinated and controlled manner.[10] As a result, the Commission's order certifying NERC as the ERO, "direct[ed] NERC to consider and propose methods for ensuring that Reliability Standards provide for an adequate level of reliability and defin[e] 'an adequate level of

[9] 16 U.S.C. 824o(c)(1) (stating, "The Commission may certify one such ERO if the Commission determines that such ERO—(1) has the ability to develop and enforce, subject to subsection (e)(2) of this section, reliability standards that provide for an adequate level of reliability of the bulk-power system;"); *and* 16 U.S.C. 824o(a)(3)(providing, The term 'reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.").

[10] 16 USC 824o(a)(4) (stating, "The term 'reliable operation' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.").

reliability.'"[11] The Commission explained that, "unless NERC further explores what it means to provide an adequate level of reliability, targeting a valuable reliability goal may not be enough to prevent a Reliability Standard from reflecting the lowest common denominator…."[12]

Accordingly, NERC developed and filed a definition of the ALR to guide Reliability Standards development, Reliability Assessments, and technical committee work. In particular, NERC defines the ALR as the state that design, planning, and operation of the Bulk Electric System ("BES") will achieve when five performance objectives are met.[13] The ALR also lists two assessment objectives for purposes of assessing risks to reliability.[14] Each objective addresses Reliable Operation of the BES over four time frames: (1) steady state (the period before a disturbance and after restoration has achieved normal operating conditions); (2) transient (the transitional period after a disturbance and during high-speed automatic actions in response); (3) operations response (the period after the disturbance where some automatic actions occur and operators act to respond); and (4) recovery and system restoration (the time period after a widespread outage through initial restoration to a sustainable operating state and

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11 Certification Order, at P 240.

12 *Id.*

13 The ALR Performance Objectives are as follows (see ALR for detail):

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

14 The ALR Assessment Objectives are as follows (see ALR for detail):

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

recovery to a new steady state).[15] These periods of time correspond to the four outcome-based abilities of both the NIAC resilience framework and the Commission proposed definition of resilience: (1) robustness; (2) resourcefulness; (3) rapid recovery; and (4) adaptability.[16]

The ALR, NIAC framework, and Commission proposed definition of resilience demonstrate the manner in which resilience is an element of Reliable Operation over time in anticipation of and in response to an event. As NIAC states, "[i]nfrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."[17] NERC interprets the Commission's proposed definition of resilience as intended to include both shorter-term elements of resilience and longer-term adaptability, consistent with the NIAC framework and NERC-filed ALR. Hence, resilience pertains to reliability before, during, immediately after, and in the longer-term after an event. In this way, the ALR avoids the "lowest common denominator" concern that the Commission expressed in the Certification Order, avoids making electric consumers insurers of the BES, and allows for regional approaches tailored to regional risks. NERC filed the latest definition of the ALR on May 10, 2013, after notice, comment, and NERC Board approval.

B. NERC Reliability Standards, Reliability Assessments, Event Analysis, Situational Awareness, and Other Activities Address Resilience.

A BPS that provides an adequate level of reliability is a resilient one. By defining specific performance and assessment objectives for the BES that include elements of resilience,

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[15] *See*, "*Informational Filing on the Definition of Adequate Level of Reliability,*" Docket No. RR06-1-000 (filed May 10, 2013), *available at*, https://www.nerc.com/pa/Stand/Resources/Documents/Adequate_Level_of_Reliability_Definition_(Informational_Filing).pdf (including the definition of the ALR and supporting technical report).

[16] *See*, NIAC Framework, at p. 13.

[17] This definition is cited in a NERC report, "*Severe Impact Resilience: Considerations and Recommendations*" (May 9, 2012).

the NERC ALR supports a highly reliable and resilient grid. As expressed in the technical report attached to the ALR:

> ALR is an outcome of a multi-dimensional effort to identify Reliability Performance and Assessment Objectives and then achieve outcomes that will support reliable operations. This multi-dimensional effort is reflected in NERC's current and evolving body of reliability standards, which work together to establish a portfolio of performance outcomes, risk reduction, and capability-based reliability standards that are designed to achieve a defense in depth against an inadequate level of reliability. Other NERC programs, such as industry alerts, reliability assessments, event analysis, education, and the compliance with and enforcement of reliability standards, are designed to work in concert with reliability standards to support reliable operation. Each of these activities should be driven by the goal of consistently achieving an adequate level of reliability.

In accordance with this intent, NERC activities across the ERO Enterprise are driven towards supporting the ALR and a resilient system. As referenced in the RTO Comments,[18] these activities include, for example, Reliability Standards, GridEx, and Electric-Information Sharing Analysis Center ("E-ISAC") work. This section describes some of the ways in which NERC Reliability Standards, Reliability Assessments, Event Analysis, and other activities address resilience, while also highlighting the RISC resilience framework reexamining what is required for ALR and resilience in today's environment.

1. Reliability Standards.

As discussed in Section III.A above, NERC must develop Reliability Standards that provide for an adequate level of reliability for Reliable Operations of the BPS. Reliability Standards are defined to:

> include requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable

[18] *See, e.g.*, MISO Comments, at pp. 19, 21, 25, and 38; CAISO Comments, at pp. 7-8, 21-22, 26, 31, 41-42, and 113-119; PJM Comments, at pp. 4, 19-20, 30-31, 53-54, and pp. 72-73; ERCOT Comments, at pp. 3, 7, 18; SPP Comments, at pp. 5-8, 11, and 18-19; NYISO Comments, at pp. 5 and 25-27; and ISO-NE Comments, at pp. 16, 18, 40, 49-50, and 53-54. Please see RTO Comments for full discussion and further examples.

> operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.[19]

NERC Reliability Standards work together to establish a portfolio of performance-based outcome, risk reduction, and capability standards applicable to entities within NERC's jurisdiction and designed to support Reliable Operations.[20] As recognized in the RTO comments,[21] several Reliability Standards relate to the BPS's capability to withstand disturbances in anticipation of potential events, manage the system after an event, and/or prepare to restore or rebound after an event.

For example, NERC has developed the following:

- Reliability Standard TPL-001-4 (*Transmission System Planning Performance Requirements*): providing planning performance requirements in anticipation of potential events;
- Reliability Standard EOP-004-3 (*Event Reporting*): requiring that entities report disturbances and events threatening reliability;
- Reliability Standard EOP-005-2 (*System Restoration from Blackstart Resources*): including requirements pertaining to preparation for system restoration from Blackstart resources after an event;
- Reliability Standard EOP-006-2 (*System Restoration Coordination*): requiring that plans and personnel be prepared to support system restoration after an event;
- Reliability Standard EOP-011-1(*Emergency Operations*): requiring operating plans to mitigate emergencies;
- Reliability Standard CIP-008-5 (*Cyber Security - Incident Reporting and Response Planning*): requiring plans to address reportable cyber security incidents;

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[19] 16 USC §824o(a)(3).

[20] In response to CAISO's question regarding inverter-based resources, NERC clarifies that Reliability Standards apply to all resources within NERC jurisdiction.

[21] *See, e.g.*, MISO Comments, at pp. 19, 21, 25, and 38; CAISO Comments, at pp. 7-8, 21-22, 26, 31, 41-42, and 113-119; PJM Comments, at pp. 4, 19-20, 30-31, 53-54, and pp. 72-73; ERCOT Comments, at pp. 3, 7, 18; SPP Comments, at pp. 5-8, 11, and 18-19; NYISO Comments, at pp. 5 and 25-27; and ISO-NE Comments, at pp. 16, 18, 40, 49-50, and 53-54. *See also* the RTO Comments for full discussion and further examples.

- Reliability Standard CIP-014-2 (*Physical Security*): including physical security requirements; and

- Reliability Standard TPL-007-1 (*Transmission System Planned Performance for Geomagnetic Disturbance Events*): providing requirements related to geomagnetic disturbances.[22]

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

- Reliability Standard TPL-007-1 (*Transmission System Planned Performance for Geomagnetic Disturbance Events*): requiring corrective action plans if a geomagnetic disturbance vulnerability assessment concludes that the system does not meet certain performance requirements;

- Reliability Standard PRC-004-5 (*Protection System Misoperation Identification and Correction*): requiring a corrective action plan after Protection System Misoperations or declaration explaining why corrective action plans are beyond the entity's control or would not improve BES reliability;

- Reliability Standard PRC-006-3 (*Automatic Underfrequency Load Shedding*): requiring a corrective action plan where the automatic underfrequency load shedding ("UFLS") design assessment determines that the UFLS program does not meet certain performance characteristics; and

- Reliability Standard PRC-016-1 (*Remedial Action Scheme Misoperations*): requiring that responsible entities take corrective actions to avoid future remedial action scheme misoperations.[23]

These examples demonstrate how Reliability Standards support resilience, without requiring the construction of facilities or otherwise exceeding the scope of section 215 of the FPA.

2. Reliability Assessments.

In recognition of NERC's commitment to assess industry performance, analyze trends, and learn from performance successes and failures, NERC performs Reliability Assessments on potential risks to the BPS. This allows the ERO Enterprise to focus on and align activities in

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

[23] *Id.*

support of Reliable Operations of the BPS. NERC Reliability Assessments must evaluate the adequacy and operating reliability of the BPS. Resource adequacy reflects the ability of the system to supply electricity to meet consumer demand at all times.[24] Operating reliability is the ability of the system to withstand sudden disturbances to system stability or unanticipated loss of components.[25] Both of these concepts reflect an assessment of the resilience of the system as a whole.

The NERC Reliability Assessments program is in and of itself a component of resilience, as it serves as a credible source of information for policy makers and stakeholders. At a high level, Reliability Assessments evaluate the: 1) adequacy of resources to meet demand and energy requirements; 2) sufficiency of ERS; 3) capability of the transmission system to accommodate projected resources and demand; 4) vulnerabilities to fuel supply, transportation, and delivery; and 5) ability to manage extreme conditions. For example, NERC's Long-Term Reliability Assessment ("LTRA") provides an annual update of a ten-year outlook identifying key issues and reliability challenges facing the BPS. NERC Reliability Assessments serve as an independent resource and technical platform for important policy discussions.

In addition to NERC's annual Reliability Assessments, NERC conducts Special Reliability Assessments on topic-specific issues that require a closer examination. A recent example of this is NERC's 2017 *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System.*[26] The assessment was primarily prepared in response to the continuing trend of increasing reliance on natural gas capacity, as

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[24] October 2017 Filing, at Exhibit B, at p. 1 (stating, "NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects).

[25] *See supra* text accompanying note 17 (regarding NIAC's definition of resilience).

[26] *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System*, NERC (Nov. 2017), *available at*, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

highlighted in several of NERC's LTRAs and by the temporary closure of the Aliso Canyon natural gas storage facility in Southern California. Prior NERC assessments concluded that the growing interdependence of the natural gas and electric infrastructure resulted in new operational and planning reliability challenges that policy makers and industry should consider when making decisions. For example, the Aliso Canyon natural gas storage facility leak underscored not only the reliance on natural gas to meet electric demand, but also how the disruption of a single key natural gas infrastructure component can affect BPS reliability. The primary take-away of the 2017 assessment was that more planning studies are needed to inform policy makers, system planners, and market operators, and to support actions addressing the unique risks each system may have. ISO-NE's "Operational Fuel-Security Analysis," reviewing New England's unique reliability risks concerning increasing dependency on natural gas generation coupled with limited natural gas pipeline, fuel storage, and transportation options, provides a good example of how NERC assessments have contributed to further analysis of regional risks.[27]

The *State of Reliability 2017 Report* ("2017 SOR") provides additional detail on how NERC uses reliability indicators to tie the performance of the BES to the reliability performance objectives in the ALR. NERC's reliability indicators address risks to the BES, recovery after events, and ERS by examining, for example:

- Metric M-2: BPS Transmission-Related Events Resulting in Loss of Load;
- Metric M-4: Interconnection Frequency Response;
- Metric M-6: Average Percent Nonrecovery Disturbance Control Standard Events;
- Metric M-7: Disturbance Control Events Greater than Most Severe Single Contingency;

[27] ISO-NE Comments, at p. 1 (discussing the Operational Fuel-Security Analysis published Jan. 17, 2018).

- Metric M-8: Interconnected Reliability Operating Limit/System Operating Limit (IROL/SOL) Exceedances;
- Metric M-9: Correct Protection System Operations; and
- Metric M-11: Energy Emergency Alerts.[28]

As demonstrated by the 2017 SOR, NERC then evaluates performance in comparison to these reliability indicators to determine whether the BES meets the ALR and whether reliability is improving.

3. Event Analysis Program.

The NERC Event Analysis Program also serves an integral component of NERC's efforts in favor of resilience by supporting continuous improvement and learning from past events. In particular, Event Analysis provides insight and guidance by identifying and disseminating valuable information to owners, operators, and users of the BPS to enable improved and more reliable operations. Through this program, NERC evaluates BPS events by undertaking appropriate levels of analysis to determine the causes of the events, promptly assuring tracking of corrective actions designed to prevent recurrence, and providing lessons learned to the industry. NERC's August 2017 *Hurricane Harvey Event Analysis Report*, for example, provided analysis of Hurricane Harvey's impact on the BPS to ensure a complete, coherent, review and documentation of the event and restoration efforts.[29]

Event Analysis has augmented its activities to take into consideration issues affecting resilience under the changing resource mix. For example, in June 2017, the NERC Planning and Operating Committees created the Inverter-based Resource Performance Task Force ("IRPTF")

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[28] *See*, 2017 SOR, at Chapter 4 and Appendix E (providing a full list of reliability indicators and discussing conclusions for the 2017 SOR), *available at*, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.

[29] *August 2017 Hurricane Harvey Event Analysis Report*, NERC (Aug. 2017), *available at*, https://www.nerc.com/pa/rrm/ea/Pages/August-2017-Hurricane-Harvey-Event-Analysis-Report.aspx.

to consider some of the new challenges associated with the changing resource mix, specifically, the proliferation of inverter based resources. The task force is producing a guideline for inverter-based resource performance to support BPS reliability. While none of the inverter-based resource events examined to date meet the threshold of a NERC reportable event, NERC has continually reviewed and reported on the small occurrences, before they can become bigger events. In 2016, NERC issued the *1200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report* regarding the Blue Cut Fire in Southern California, detailing issues created by solar inverter settings and recommendations to help mitigate future interruptions. The October 2017 *Canyon 2 Fire Disturbance Report,* described the Canyon 2 Fire in the Southern California area, key findings regarding solar inverter issues, and recommendations thereafter to support reliable operation of the BPS. Further, in February 2018, NERC published the *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report.* The Event Analysis process provides valuable input for training and education, reliability trend analysis efforts, and Reliability Standards development, all of which support continued improvement of reliability. As a result, Event Analysis operates as one of the pillars of NERC's foundational activities in support of resilience.

NERC strives to develop a culture of reliability excellence that promotes and rewards aggressive self-critical review and analysis of operations, planning, and critical infrastructure protection processes. This helps avoid similar or repeated events through the timely identification and correction of event causes and the sharing of lessons learned. For example, based on analysis in the *1200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC recently issued recommendations for reliability through an Alert after NERC observed loss of solar resources during transmission disturbances due to the low-

voltage ride through setting of photovoltaic inverters.[30] Other NERC Alerts have addressed topics such as supply chain risk, threats targeting the electric industry and other critical sectors, vegetation management, and frequency response.[31] These Alerts demonstrate how Event Analysis contributes to resilience by focusing on the robustness of the grid, adaption to lessons learned, risks to reliability, and the changing resource mix.

4. Situational Awareness and Information Sharing Through the E-ISAC and NERC Bulk Power System Awareness.

NERC's activities as part of the E-ISAC and Bulk Power System Awareness ("BPSA") also contribute to resilience. A major disruption in electric service due to an event on the system, such as cyber-security incident or physical attack, could have far-reaching effects. As a result, the ERO Enterprise has instituted several initiatives to ensure a more resilient system, better secured against cyber and physical threats to the grid.

The E-ISAC serves as the primary security communications channel for the electricity industry and enhances industry readiness and ability to respond to threats, vulnerabilities, and incidents that could affect the BPS. The E-ISAC's Cybersecurity Risk Information Sharing Program ("CRISP") also provides a voluntary program to facilitate real-time, computer-to-computer data exchange involving potential security threats identified through monitoring participating utility networks. Further, the E-ISAC holds a biannual GridEx conference to allow participants the opportunity to self-assess their emergency response and recovery plans through simulated security exercises featuring stresses on the system.

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[30] *See, Loss of Solar Resources during Transmission Disturbances due to Inverter Settings*, NERC (June 20, 2017), *available at*, https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance.pdf.

[31] *See*, NERC Alerts, *available at*, https://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx.

Similarly, the NERC BPSA collects and analyzes information on system disturbances and other incidents that affect the North American BPS. The BPSA then disseminates this information to internal departments, registered entities, regional organizations, and governmental agencies as necessary. In addition, the BPSA monitors ongoing storms, natural disasters, and geopolitical events that may affect or are currently affecting the BPS. The BPSA issues alerts to NERC registered entities and the electricity sector upon discovering, identifying or receiving information that is critical to ensuring the reliability of the BPS. These activities by the E-ISAC and BPSA help support a BPS better able to anticipate, withstand, respond to, recover from, and learn from events.

5. The RISC Resilience Framework.

Building on the efforts summarized above, and as shown in the following table, the RISC identified a variety of ongoing NERC activities for resilience that correspond to the NIAC framework and Commission proposed definition of resilience. The elements of the RISC resilience framework are very similar to the NIAC framework with certain clarifications shown below in red. For example, the Critical Infrastructure Protection Committee suggested that NERC could improve the resilience framework by incorporating detection as an explicit aspect of resourcefulness. The RISC is examining whether further NERC action on resilience is appropriate. At the May 2018 Member Representatives Committee Meeting, the RISC will summarize its analysis and any recommendations for the NERC Board.

NIAC Resilience Constructs[32]	Key Programs and Activities	Specific Efforts\Tools
Robustness—The ability to continue operations in the face of disaster. In some cases, it translates into designing structures or systems to be strong enough to take a foreseeable punch. In others, robustness requires devising substitute or redundant systems that can be brought to bear should something important break or stop working. Robustness also entails investing in and maintaining elements of critical infrastructure so that they can withstand low probability but high consequence events.	• Reliability and Emerging Risk Assessments • Risk, Event and Performance Monitoring • Technical Committee work, including special projects • Mandatory Reliability Standards • Reliability Guidelines and technical reference documents • System Operator Certification and Credential Maintenance • System Operator Training • E-ISAC information sharing programs	• Alerts • State of Reliability Report o GADS o TADS o DADS o Protection system misoperations o TEAMS o FR Performance • Long-Term Reliability Assessment • Key Reliability Standards: o TPL (Extreme) o EOP o Blackstart Restoration o Personnel Credentials • GridEx • Security conferences and information sharing (e.g. GridSecCon) • Supply Chain Security • Security Practices
Resourcefulness—The ability to skillfully detect and manage a disaster as it unfolds. It includes identifying options, prioritizing what should be done both to control damage and to begin mitigating it, and communicating decisions to the people who will implement them. Resourcefulness depends primarily on people, not technology.	• Situational Awareness and Industry Coordination • Government Coordination • Cross-Sector Information Sharing • Mandatory Reliability Standards/Functional Model • Reliability Guidelines and technical reference documents • System Operator Certification and Credential Maintenance • System Operator Training	• BPSA information sharing tools and processes • E-ISAC information sharing tools and processes • Formation of a Crisis Action Team to support industry and governmental coordination • GridEx • Standards requirements o Reliability Coordinators o Transmission Operators o Communications
Rapid recovery—The capacity to get things back to normal as quickly as possible after a disaster in a coordinated and controlled manner. Carefully drafted contingency plans, competent emergency operations, and the means to get the right people and resources to the right places are crucial.	• Situational Awareness, Industry Coordination • Government Coordination • Cross-Sector Information Sharing • Reliability Guidelines and technical reference documents • System Operator Certification and Credential Maintenance • System Operator Training	• Support for Electric Sector Coordinating Council activities • BES simulation • System restoration coordination

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

C. The Commission Should Continue Policy Reform Recognizing Attributes of a Reliable and Resilient BPS.

As detailed in NERC's Comments in Docket No. RM18-1-000, the changing resource mix is altering the operational characteristics of the BPS.[33] This warrants reexamination of what is necessary to maintain a reliable system, including its resilience. NERC Reliability Assessments demonstrate that resilience depends on the operating characteristics of the evolving resource mix and the capability of such resources to provide ERS. The Event Analysis reports referenced above and Alert on solar inverter settings further illustrate how the changing resource mix may affect ERS. As highlighted in SPP's Comments, ERS (such as capacity, voltage support, system inertia, and frequency response) "supports resilience by virtue of unique characteristics and abilities to respond to a significant disturbance."[34] NERC supports continued Commission action, such as the recent primary frequency response order, recognizing the value

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

[33] *Comments of the North American Electric Reliability Corporation in Response to Grid Reliability and Resilience Pricing Notice of Proposed Rulemaking*, Docket No. RM18-1-000 (filed Oct.23, 2017) ("October 2017 Filing").

[34] SPP Comments, at p. 16.

of ERS and requiring integration of newly interconnecting resources in a manner that supports a reliable and resilient grid.[35]

In addition to ERS, fuel assurance and diversity are critical elements of a reliable and resilient system. A balanced portfolio of generation resources and transmission infrastructure ensures that the system has adequate capacity to meet consumer needs and is ready to respond to events.[36] As the resource mix changes, variable energy resources are expanding and the balancing resource often tends to be natural gas-fired generation. Natural gas-fired resources serve a key function in the generation fleet and depend upon a generally reliable fuel supply, for which fuel is transported on a "just-in-time" basis. Comments in this proceeding have underscored implications of this trend for reliability across regions.[37] NERC's October 2017 Filing also discussed how single source fuel dependency could have adverse impacts under common mode outages.[38] Recognizing that generating capacity alone does not guarantee dispatchable energy, it is also important to understand the difference in the potential outage rates of natural gas fired generating units with firm gas transportation compared to those units that lack firm transportation. As highlighted in NERC's 2014/2015 Winter Reliability Assessment, "increased reliance on gas-fired generation requires new approaches for assessing reliability."[39]

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35 *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, Order No. 842, 162 FERC ¶ 61,128 (2018).

36 October 2017 Filing, Exhibit B, at p. 1.

37 *See, e.g.*, MISO Comments, at pp. 23 and 37; CAISO Comments, at pp. 15 and 171; PJM Comments, at pp. 5-8 and 26; ERCOT Comments, at p. 19; ERCOT Comments, at p. 5; NYISO Comments at pp. 25 and 31; and ISO-NE Comments, at pp. 22 and 26. *See also* the RTO Comments for full discussion and further examples.

38 October 2017 Filing, at Exhibit B, at p. 1. Natural gas fuel dependency may be particularly concerning in areas where: (i) generators rely on interruptible gas pipeline transportation; (ii) natural gas interstate pipelines are constrained to meet demand beyond what has been contracted and committed; and (iii) there is greater reliance on natural gas-fired generation as a "primary" generation resource

39 2014–2015 Winter Reliability Assessment, at p. 8.

Without unduly favoring any generation resource or infrastructure, the Commission should consider policies that build upon its prior examination of natural gas – electric coordination.[40] For example, the Commission could encourage firm transportation, multiple pipeline connections, and dual-fuel capability as measures to reduce the risk of common-mode failure and wider-spread reliability challenges from fuel supply disruptions. Further, the Commission could consider requiring that resource adequacy assessments account for potential reliability ramifications associated with the "just-in-time" natural gas fuel delivery model. Finally, the Commission could consider whether it would be beneficial to pursue market rules that would provide assurances that generators will perform in normal and extreme circumstances. The RTO comments similarly highlighted mechanisms that could help or were already helping their region address potential risks associated with natural gas supply contingencies.[41] As NERC recommended in Docket No. RM18-1-000, the Commission should consider further policies acknowledging the value of reliability attributes provided by all resources, and require integration of new resources in a manner that supports a reliable electric grid, resilient in the face of events on the system.

[40] *See, e.g., Request for Comments of Commissioner Moeller on Coordination between the Natural Gas and Electricity Markets*, Docket No. AD12-12-000 (Feb. 3, 2012).

[41] *See, e.g.*, NYISO Comments, at pp. 31-32; ERCOT Comments, at p. 19; ISO Comments, at pp. 7 and 11-12; *and* PJM Comments, at pp. 5-8. Please see RTO Comments for full discussion and further examples.

IV. CONCLUSION

NERC appreciates the Commission's attention to resilience. As discussed above, resilience is an element of reliability in relation to an event. NERC has defined the adequate level of reliability to encompass aspects of resilience. In accordance with the ALR and section 215 of the FPA, NERC Reliability Standards, Reliability Assessments, Event Analysis, and other activities address resilience, even as the RISC continues examining whether further action is appropriate. NERC recommends that the Commission continue to pursue policies supporting reliability, including resilience.

Respectfully submitted,

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Date: May 9, 2018

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service lists compiled by the Secretary in Docket No. AD18-7-000.

Dated at Washington, DC this 9th day of May 2018.

/s/ Courtney M. Baughan

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Northeast Power Coordinating Council, Inc. Regional Standards Committee

2015-09 Establish and Communicate System Operating Limits - FAC-010, FAC-011, FAC-014

Guy V. Zito

NPCC AVP - Standards

FAC Standards Under Review

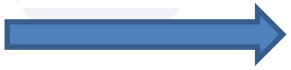
- FAC-010-3 - System Operating Limits Methodology for the Planning Horizon (Proposed for retirement)
- FAC-011-4 - System Operating Limits Methodology for the Operations Horizon 58.1% Approval
- FAC-014-3 – Establish and Communicate System Operating Limit 63.1% Approval
- FAC-015-1 - Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology (New) 56.5% Approval
- System Voltage Limit Definition 68.59% Approval

Original Construct – Circa 2008

FAC Standards

1. FAC-011: SOL Methodology must contain requirements that SOLs be established to "provide for" acceptable system performance:
   a. Pre- and post-Contingency performance criteria and other "rules" (R2)
2. FAC-014: TOPs required to establish SOLs per the RC's methodology (those that result in acceptable pre- and post-Contingency performance described in R2)

SOLs are communicated to operators



TOP/IRO Standards

1. Requirements to Operate within SOLs

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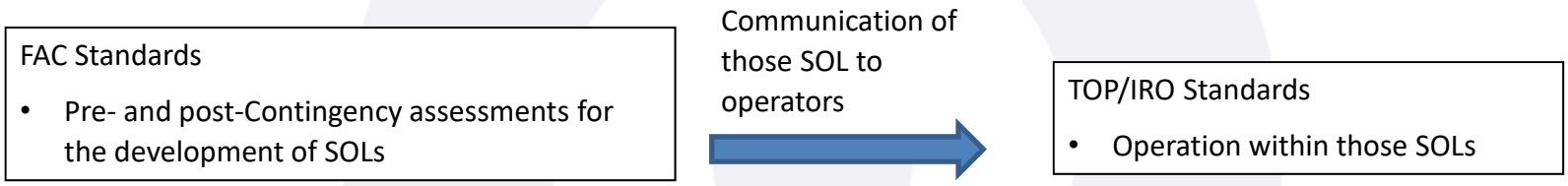
Original Construct – Circa 2008



Assessments for the post-Contingency state required to be done here per FAC-011 and FAC-014. Post-Contingency criteria performance reflected in the SOL.

No requirement for real-time evaluation of the post-Contingency state here. Operations driven by using SOLs that "provide for" acceptable post-Contingency system performance.

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Current Construct – Circa 2017/2018

FAC Standards (no change)

1. FAC-011: SOL Methodology must contain requirements that SOLs be established to "provide for" acceptable system performance:
   a. Pre- and post-Contingency performance criteria and other "rules" (R2)
2. FAC-014: TOPs required to establish SOLs per the RC's methodology (those that result in acceptable pre- and post-Contingency performance described in R2)

SOLs are communicated to operators

The current FAC standards and the TOP/IRO standards don't work together – they are based on differing constructs

TOP/IRO Standards

1. Requirements for TOPs and RCs to perform OPAs to determine SOL exceedance
2. Requirement for TOPs and RC to develop and communicate Operating Plans for SOL exceedances identified in OPAs
3. Requirement for TOPs and RCs to perform RTAs
4. Requirement for TOPs and RCs to implement Operating Plans for SOL exceedances

OPA and RTA defined to include an assessment of the pre- and the post-Contingency states and has required inputs

Now it is the OPA and RTA paired with the implementation of the Operating Plan that "provides for" acceptable pre- and post-Contingency performance – not the "SOL" in and of itself as in the prior construct.

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Original FAC/TOP/IRO Construct

1. SOL Methodology developed (FAC-011)
2. SOLs are established that "provide for" acceptable system performance (FAC-014)
3. SOLs given to operators (FAC-014)
4. Operators operate within those SOLs (TOP/IRO)

New TOP/IRO Construct

1. TOPs and RCs perform OPAs and RTAs and develop/implement Operating Plans for SOL exceedances
2. OPAs and RTAs are an assessment of the pre- and post-Contingency states

FAC SDT Objective – to create a FAC construct that works with the TOP/IRO construct so that there is a single cohesive construct

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This approach creates a single cohesive construct

Proposed New FAC Construct

1. Focus the FAC standards on inputs to OPAs and RTAs
2. SOLs no longer "provide for" acceptable system performance by themselves as they did in the prior construct
3. SOLs are Facility Ratings, System Voltage Limits, and stability limits used in operations

SOLs are communicated to operators

Existing TOP/IRO Construct

1. SOLs are *inputs* to OPAs and RTAs
2. Assessments for the pre- and post-Contingency states through OPAs and RTAs
3. Development and implementation of Operating Plans

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Issues to be resolved by SDT

- Nowhere does it state exactly what the operational performance criteria are (acceptable performance criteria for the pre- and post-Contingency states)
- However those performance criteria are stated, they need to be tied to the TOP/IRO standards relating to SOL exceedance
- They are currently in FAC-011 because in the old construct SOLs "provide for" acceptable system performance
- In the new construct, SOLs are an input to OPAs and RTAs…and the OPAs and RTAs paired with the development and implementation of Operating Plans "provide for" acceptable system performance
- Operating performance criteria (acceptable performance criteria for the pre- and post-Contingency states) need to reside somewhere…but where?

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Original SDT Plan…

FAC Standards

1. Proposed standards exclusively about establishment and communication of SOLs (Facility Ratings, System Voltage Limits, stability limits)
2. FAC standards not about "how to operate the system"

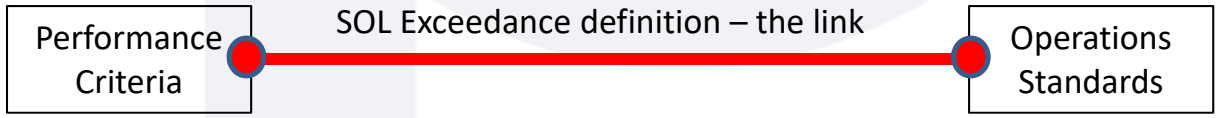
TOP/IRO Standards

1. About "how to operate the system"
2. Primary focus on "SOL exceedance" (little "e")
3. SOL exceedance (little "e") requirements drive and govern reliable operations

Performance Criteria (acceptable pre- and post-Contingency system performance criteria)

1. Directly describes "how the system should be operated"
2. FAC SDT original plan: put the performance criteria into an SOL Exceedance definition, and implement the SOL Exceedance definition into the TOP/IRO standards that currently use SOL exceedance (little "e") and in other standards where appropriate

This approach *directly* ties the performance criteria to operations in TOP/IRO.



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Status

- The industry doesn't like the proposed definition of SOL Exceedance
  - Too burdensome for compliance
  - Renders overly conservative operations
  - Shouldn't have requirements for "good practice" but rather for unacceptable operations
- Industry wants a definition that the SDT believes is not reliable
  - I.e., you don't have to implement the Operating Plan until the actual loading on a Facility has exceeded the Facility Rating for an unacceptable time duration (pointing to what we believe to be flaw in the NERC SOL White Paper)
- Team will create a revised definition for SOL but will not create any definition for SOL Exceedance or SOL Violation
- Team plans to describe the operations performance criteria in a requirement in FAC-011 and requiring RCs and TOPs to use that performance criteria in a requirement in FAC-014

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

Questions or Comments ?

A. Introduction

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

2. Number: FAC-010-3

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

4. Applicability

4.1. Planning Authority

5. Effective Date: See Implementation Plan for the Revised Definition of "Remedial Action Scheme"

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Remedial Action Schemes.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority 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 SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years~~. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retirement approved by FERC effective January 21, 2014.)

1.4.2 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology. (Retirement approved by FERC effective January 21, 2014.)

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.	The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6	The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.	The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2-, R2.3, R2.4, R2.5, or R2.6
R3	The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in

Requirement	Lower	Moderate	High	Severe
		OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Planning Authority received documented technical	The Planning Authority received documented technical	The Planning Authority received documented technical	The Planning Authority received documented technical

Requirement	Lower	Moderate	High	Severe
(Retirement approved by FERC effective January 21, 2014.)	comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word “each” from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2	June 24, 2008	Adopted by Board of Trustees; FERC Order 705	Revised
2		Changed the effective date to July 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2.1	November 5, 2009	Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	April 19, 2010	FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	

2.1	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2.1	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving FAC-010-3. Docket No. RM15-13-000.	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Mapping Document for FAC-010-3

The Project 2015-09 standard drafting team (SDT) is proposing the retirement of the NERC FAC-010-3 Reliability Standard. The SDT further proposes a new paradigm regarding the coordination of the Planning Assessment (TPL-001-4) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new paradigm consists of a new FAC-015-1 Reliability Standard and revisions to the existing FAC-011-3 and FAC-014-2 Reliability Standards. The SDT proposal for a new FAC-015-1 Reliability Standard, along with the proposed revisions contained in FAC-011-4 and FAC-014-3, represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to address the reliability issues that are ultimately faced in Real-time operations.

The proposed construct does not make use of an SOL Methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4. However, FAC-015-1, Requirements R1 – R3 ensure that Planning Assessments performed for the Near-Term Transmission Planning Horizon, are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the Reliability Coordinator's (RC's) SOL Methodology. FAC-015-1, Requirements R1 – R3 respectively address Facility Ratings System steady state voltage limits, and stability performance criteria used in the development of Planning Assessments. These requirements focus on the three components of SOLs used in operations and facilitate continuity between operations and planning. Implementing the processes required in FAC-015-1 Requirements R1 – R3 provides the Planning Coordinator (PC) with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the Reliability Coordinator's SOL Methodology.

FAC-015-1, Requirements R4 and R5 address the communication and use of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in Planning Assessments between PCs and Transmission Planners (TPs).

FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation, along with key supporting information, identified in the Planning Assessments to the RCs and to impacted Transmission Operators (TOPs). This information may be useful to RC and TOPs in the establishment of stability limits and IROLs that will ultimately be used in Real-time operations.

By implementing Requirements R1 – R6 of FAC-015, Facility Ratings, System steady-state voltage limits and stability criteria used in the development of the Planning Assessment are effectively bounded by the Facility Ratings, System Voltage Limits, and stability performance criteria define and established in accordance with the RC's SOL Methodology (FAC-011-4 & FAC-014-3). Furthermore, potentially critical stability information is communicated by planners to operators. The result is an improvement in reliability by ensuring continuity between planning and operations.

The remainder of this document provides a mapping of the existing requirements in FAC-010-3 to the proposed action by the SDT. For easier reference applicable information from Table 1 of TPL-001-4 is included below. References to notes a – j and Planning Events P0 – P7 will be included in the mapping table where appropriate.

TPL-001-4 Table 1 (steady state & stability performance criteria notes for planning events)

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category P0 No Contingency
(Initial Condition - Normal System)

Category P1 Single Contingency
(Initial Condition - Normal System)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P2 Single Contingency
(Initial Condition - Normal System)

1. Opening of a line section w/o a fault
2. Bus Section Fault (SLG fault)
3. Internal Breaker Fault (non-Bus-tie Breaker) (SLG fault)
4. Internal Breaker Fault (Bus-tie Breaker) (SLG fault)

Category P3 Multiple Contingency
(Initial Condition - Loss of generator unit followed by System adjustments)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P4 Multiple Contingency
(Initial Condition - Normal System)

1. Generator (SLG fault)
2. Transmission Circuit (SLG fault)
3. Transformer (SLG fault)
4. Shunt Device (SLG fault)
5. Bus Section (SLG fault)
6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus

Category P5 Multiple Contingency
(Initial Condition - Normal System)
Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following:
Generator (SLG fault)

1. Transmission Circuit (SLG fault)
2. Transformer (SLG fault)
3. Shunt Device (SLG fault)
4. Bus Section (SLG fault)

Category P6 Multiple Contingency
(Initial Condition - Loss of one of the following followed by System adjustments.

1. Transmission Circuit
2. Transformer
3. Shunt Device
4. Single Pole of DC line)

Loss of one of the following:

1. Transmission Circuit (3 Ø fault)
2. Transformer (3 Ø fault)
3. Shunt Device (3 Ø fault)
4. Single Pole of DC line (SLG fault)

Category P7 Multiple Contingency
(Initial Condition - Normal System)
The loss of:

- Any two adjacent (vertically or horizontally) circuits on common structure (SLG fault)
- Loss of a bipolar DC line (SLG fault)

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R1.	The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:	**FAC-010-3, Requirement R1 is addressed by:** 1. TPL-001-4, Requirements R1, R5, and R6 2. MOD-032-1, Requirement R2 3. FAC-008-3 Requirements R2 and R3 **TPL-001-4, Requirement R1:** **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. **R1.1** System models shall represent: **R1.1.1.** Existing Facilities **R1.1.2.** Known outage(s) of generation or Transmission	SOLs developed by the PC and TP for use in the planning horizon are addressed in other standards as described below. SOLs used in the Operations Planning, Same-day Operations, and Real-time Operations time horizons are developed in accordance with the RC's methodology as specified in FAC-011-4. The determination of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in the Long-term Planning time horizon are addressed as follows. It is important to note the new FAC-015-1 Reliability Standard bounds the following items as stated in the introduction of this document. **Facility Ratings** PCs and TPs are required, by TPL-001-4 Requirement R1, to maintain System models and to use data consistent with that which has been provided in accordance with MOD-032-1 (which supersedes the MOD-010 and MOD-012 standards). Facility Ratings are included in this data. These Facility Ratings: • Are determined in accordance with a Generator Owner's (GOs) or TO's Facility Ratings Methodology as required by FAC-008-3 R2 & R3 and

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Facility(ies) with a duration of at least six months. **R1.1.3.** New planned Facilities and changes to existing Facilities **R1.1.4.** Real and reactive Load forecasts **R1.1.5.** Known commitments for Firm Transmission Service and Interchange **R1.1.6.** Resources (supply or demand side) required for Load **TPL-001-4, Requirement R5:** **R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. **TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document,	• Are provided to the PC and TP by the Facility Owner as required by MOD-032-1 R2. **System Steady-State Voltage Limits** TPL-001-4 R5 requires the TP and PC to have criteria for acceptable System steady state voltage limits. These limits are used in the Planning Assessments. **Transient and Voltage Stability Performance Criteria** TPL-001-4 Requirement R6 requires the TP and PC to have documented criteria to identify system conditions such as Cascading, voltage instability, or uncontrolled islanding. This criteria is applied when performing Planning Assessments to identify instances of Cascading, voltage instability, or uncontrolled islanding.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. **MOD-032-1, Requirement R2:** **R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. **FAC-008-3, Requirement R2:** **R2.** Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		interconnection with the Transmission Owner that contains all of the following… **FAC-008-3, Requirement R3:** **R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following…	
R1.1.	Be applicable for developing SOLs used in the planning horizon.		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL Methodology. The requirements from TPL-001-4, MOD-032-1, and FAC-008-3 discussed above are applicable to the Long-term Planning time horizon and supersede the need for developing planning horizon SOLs.
R1.2.	State that SOLs shall not exceed associated Facility Ratings.	**TPL-001-4 Table1:** **Note: 'f'**	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL Methodology. TPL-001-4 is constructed such that a Corrective Action Plan is developed to address those conditions where Facility Ratings are forecasted

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
			to be exceeded in response to a planning event. The implementation of the Corrective Action Plan ensures the System is planned so there are no exceedances of Facility Ratings.
R1.3.	Include a description of how to identify the subset of SOLs that qualify as IROLs.	**TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of IROLs in accordance with the PC's SOL Methodology. In the proposed construct, PC and TP identify instances of instability, Cascading, or uncontrolled separation per the criteria developed in TPL-001-4 and communicate those instances to the Reliability Coordinator via FAC-015-1, Requirement R6. IROLs are established by the RC as required by FAC-014-3. TPL-001-4, Requirement R6 requires PC and TPs to document criteria or a methodology for use in identifying Cascading, voltage instability, or uncontrolled islanding in the analysis conducted for the annual Planning Assessment. This criterion addresses the conditions described in the definition for Interconnection Reliability Operating Limit (IROL).
R2.	The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES	**TPL-001-4 Table 1**	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	performance consistent with the following:		horizon. The SDT proposes retiring Requirement R2 and its subparts due to redundancy with TPL-001-4 performance requirements contained in Table 1 notes a – j. The TPL-001-4 criteria provide the performance criteria for studies within the planning horizon that serve as the basis of the annual Planning Assessment the standard requires the PC and TP produce.
R2.1.	In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'** **TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Pre-contingency (Category P0) Bulk Electric System (BES) planned performance is addressed by TPL-001-4 Table 1 with notes a, f, and g specifying the applicable performance criteria. BES planned performance is based on expected system conditions and changes to system topology such as Facility outages as specified in TPL-001-4 Requirement R1.
R2.2.	Following the single Contingencies[1] identified in	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'**	Single contingency (Categories P1 & P2) BES planned performance is addressed by TPL-001-4

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		Table 1 with notes a through j specifying the applicable performance criteria.
R2.2.1.	Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	**TPL-001-4 Table1:** **Note: 'd'** **TPL-001-4 Table 1:** Categories P1 & P2 Single Contingency Events **TPL-001-4 Table 1:** **Footnote 2.** Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.3.	Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	**TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to single contingencies are addressed in approved TPL-001-4 Table 1, including Consequential Load Loss and System Reconfiguration.
R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	**TPL-001-4 Table1: Note: 'b'**	
R2.3.2.	System reconfiguration through manual or automatic control or protection actions.	**TPL-001-4 Table1: Note: 'e'**	
R2.4.	To prepare for the next Contingency, system adjustments may be made,	**TPL-001-4 Table1: Note: 'e'**	Allowable System adjustments for BES planned performance to prepare for the next

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	including changes to generation, uses of the transmission system, and the transmission system topology.	**TPL-001-4 Table 1:** Footnote 9**.** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non- Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.	Contingency are addressed TPL-001-4 Table 1 note e and footnote 9.
R2.5.	Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability;	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g' 'j'** **TPL-001-4 Table1:** Categories P3 – P7 Multiple Contingency Events	Multiple contingency BES planned performance is addressed as Category P3 - P7 in TPL-001-4 Table 1. These include the multiple contingency events that start with all Facilities in service (P4, P5 & P7). Notes a through j from Table 1 (above) specify the applicable performance criteria.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		
R2.6.	In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	**TPL-001-4, Requirement R2.7.3** **TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to multiple contingencies are addressed in TPL-001-4 Requirement R2.7.3 and Table 1, including all actions that were acceptable in response to single Contingencies discussed above; and load shedding and curtailment of Firm Transmission Service.
R2.6.1.	Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	**TPL-001-4, Requirement R2, Part 2.7.3.** **2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking	Table 1 in TPL-001-4 specifies the conditions where service interruption is acceptable.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. **TPL-001-4 Table 1:** Footnote 9 (refer to R2.4 section) Footnote 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.	
R3.	The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (R5 had since been retired). Requirement R3 was identified as "More appropriate as a Guideline. This is a checklist."
R3.1.	Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	**TPL-001-4, Requirement R1:** **R1**. (refer to Requirement R2.1 section above)	Study model used for BES planned performance is specified in approved TPL-001-4, Requirement R1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R3.2.	Selection of applicable Contingencies.	**TPL-001-4 Table1:** Categories P1 – P7 Planning Events	Applicable contingencies for BES planned performance are specified in approved TPL-001-4 Table 1.
R3.3.	Level of detail of system models used to determine SOLs.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Model details for BES planned performance are specified in approved TPL-001-4, Requirement R1.
R3.4.	Allowed uses of Remedial Action Schemes.	**TPL-001-4, Requirement R2, Part 2.7:** **2.7.** For planning events shown in TPL-001-4 Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with TPL-001-4, Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: **2.7.1.** List System deficiencies and the associated actions needed to	TPL-001-4, Requirement R2.7 requires the development of a Corrective Action Plan to address system deficiencies. The Corrective Action Plan is required to include any automatic tripping or other automated protection that is required to meet the performance criteria in TPL-001-4 Table 1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		achieve required System performance. Examples of such actions include: • Installation, modification, or removal of Protection Systems or Special Protection Systems • Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. • Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.	
R3.5.	Anticipated transmission system configuration, generation dispatch and Load level.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Anticipated transmission dispatch, generation, and load levels are incorporated into study models used for BES planned performance as specified in TPL-001-4, Requirement R1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V	See mapping for Requirement R1, Part 1.3	See mapping for Requirement R1.3
R4.	The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon. The modeling and performance requirements as well as the reliability objectives of FAC-010-3 are redundant with those in TPL-001-4. Furthermore, the Planning Assessment required by TPL-001-4 is distributed, in accordance with TPL-001-4 Requirement R8 and IRO-017 Requirement R3, to all applicable entities listed in FAC-010-3 Requirement R4. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (Requirement R5 had since been retired). Requirement R4 was identified as "More appropriate as a Guideline. Description of
R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	**TPL-001-4, Requirement R8:** **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.	
R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	**TPL-001-4, Requirement R8:** **R8.** (refer to Requirement R4, Part 4.1 section above) **IRO-017-1, Requirement R3:**	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators**.**	appropriate coordination does not rise to a Standard.”
R4.3.	Each Transmission Planner that works in the Planning Authority’s Planning Authority Area.	See mapping for Requirement R4, Part 4.1	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Impacted by the Retirement of FAC-010-3

Project 2015-09 Establish and Communicate System Operating Limits

STD	Standard Reference	Comment / Proposed Action
BAL standards		No Action Required
CIP standards		
CIP-002-5.1a	Attachment 1: 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.	This reference directly refers to the Planning Coordinator (PC), Transmission Planner (TP), and Reliability Coordinator (RC) and certain facilities that have been identified by these entities as being critical to the derivation of an IROL. After retirement of FAC-10-3, PCs and TPs will no longer be required to establish IROLs using FAC-010-3; however, IROLs will continue to be required to be established by the RC. Similar to Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a, FAC-014-3, Requirement R6, requires the Facilities (generation and/or transmission) identified by the RC as critical to the derivation of the IROL to be communicated to the Generator Owners (GO) and Transmission Owners (TOs). FAC-014-3 Requirement R6 specifically states, “Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a

		list of Facilities owned by that entity that are critical to the derivation of the IROL." While Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a could benefit from a revision to eliminate the PC and TP in response to the retirement of FAC-010-3, no reliability gap is created if FAC-010-3 is retired prior to the revision of Requirement R2, Part 2.6 of Attachment 1 given the above requirements for the RC. Consideration should also be given to modify Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a to focus on identification of Facilities – not the identification of IROLs as the limits themselves are immaterial to the goal. Accordingly, it may be appropriate for the Facilities identified as applicable to the CIP standard include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon. **Recommendations:** Revise Requirement R2, Part 2.6 of Attachment 1 in response to the retirement of FAC-010-3 to eliminate PC and TP responsibility for identification of Facilities critical to the derivation of IROLs. A future team should determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's

		Planning Assessment for the Near-Term Transmission Planning Horizon.
CIP-014-2	Applicability 4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.	This reference directly refers to the PC and TP (and RC) and certain facilities that have been identified by these entities as being critical to the derivation of an IROL. Similar to 4.1.1.3 of the Applicability section of CIP-014-2, FAC-014-3, Requirement R6 requires the Facilities (generation and/or transmission) identified by the RC as critical to the derivation of the IROL to be communicated to the GOs and TOs. FAC-014-3 Requirement R6 specifically states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." While 4.1.1.3 of the Applicability section of CIP-014-2 could benefit from a revision to eliminate the PC and TP in response to the retirement of FAC-010-3, no reliability gap is created if FAC-010-3 is retired prior to the revision of Requirement R2, Part 2.6 of Attachment 1 given the above requirements for the RC. Consideration should also be given to modifying 4.1.1.3 of the Applicability section of CIP-014-2 to focus on identification of Facilities – not the identification of IROLs as the limits themselves are immaterial to the goal. Accordingly, it may be appropriate for the Facilities identified as applicable to the CIP standard include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in

		the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon. **Recommendations:** Revise 4.1.1.3 of the Applicability section of CIP-014-2 in response to the retirement of FAC-010-3 to eliminate the PC and TP responsibility for identification of Facilities critical to the derivation of IROLs. A future team should determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
COM standards		No Action Required
EOP standards		No Action Required
FAC standards		
FAC-003-4	**Introduction:** **4.2.2.** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. **4.3.1.2.** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or …	The Applicability section of the Introduction specifies "applicable lines" and includes overhead transmission lines (< 200 kV) identified as an element of an IROL by the PC. Requirements R1 and R2 reference "applicable lines" and IROLs as well. "Applicable lines" are specified for the identification of overhead transmission lines that require the levels of vegetation management required by the standard. All overhead transmission lines that operate at 200 kV and above are included as "applicable

	Requirements **R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below… **R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path.	lines" (4.2.1). Qualifications are then being made to include < 200 kV transmission lines (4.2.2 & 4.2.3) that have a high enough level of criticality to require the same vegetative management requirements as higher voltage transmission lines. The actual limit is not the focus, but rather, the identification of transmission lines that, when compromised, present the risk of potentially severe consequences and therefore should be subject to stricter vegetation management. The retirement of FAC-010 does not create a reliability gap here. The language in Parts 4.2.2 and 4.3.1.2 of FAC-003-4 specifically addresses IROLs determined in the planning horizon pursuant to FAC-014; however, IROLs are required to be established by the RC, and the Facilities critical to the derivation of the IROL are communicated to the GOs and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." FAC-003-4 is applicable to GOs and TOs. Accordingly, these entities are made aware of IROLs and the facilities critical to the derivation of those IROLs from the RC as per FAC-014-3 Requirement R6 above. While Parts 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired

		prior to the revision of these subparts given the above requirements for the RC. **Recommendations:** Revise 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 in response to the retirement of FAC-010-3 to eliminate references to the PC determining IROLs. A future team should determine the appropriateness for the elements identified as applicable to 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
FAC-013-2	**Requirements** **R1.2.** A statement that the assessment shall respect known System Operating Limits (SOLs).	R 1.2 is not specific to Planning Horizon SOLs but the applicability of the overall standard is for PCs. The retirement of FAC-010-3 does not create a reliability gap here as SOLs will continue to be established by TOPs and communicated to PCs through FAC-014-3 Requirement R5. The PC can then use the SOL information to satisfy Requirement R1, R1.2. Requirement R1.2 does not specify whether the SOLs are sourced from the RC or by the PC. **Recommendations:** Consideration should also be given to clarify FAC-013-2 Requirement R1.2 to eliminate the use of the SOL term as applied to the Planning Coordinators Transfer Capability assessment.

		Possible solutions include changing the language of Requirement R1, R1.2 to reference the performance requirements per Table 1 of TPL-001-4, or revising the language to replace SOL with "Facility Ratings, System steady-state voltage limits, and the Transmission Planners' stability criteria." A future team should consider eliminating the use of the SOL term as applied to the Planning Coordinators Transfer Capability assessment as described above.
FAC-014-2	Requirements R3 – R5	Under Revision
INT standards		No Action Required
IRO standards		No Action Required
MOD standards		No Action Required
NUC standards		No Action Required
PER standards		No Action Required
PRC standards		
PRC-002-2	**Requirements:** **R5.** Each Responsible Entity shall: **5.1.** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.2.** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).	Direct language around SOL and IROL does not specify PC SOL methodology and therefore does not preclude the RC's methodology from determining the applicable limits. However, the time horizon for the requirement is "long-term planning." Additionally, the SOLs referred to are stability based only. The retirement of FAC-010-3 does not create a reliability gap here. IROLs and stability-related SOLs are communicated to the GOs

	5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).	and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." The Applicability section of PRC-002-2 describes the Responsibly Entities: 4.1.1 Eastern Interconnection – Planning Coordinator 4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator 4.1.3 Western Interconnection – Reliability Coordinator 4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator Regardless of the designation of the Responsible Entity in a given Interconnection, either is able to provide the GOs and TOs the information in Requirement R5, Parts 5.1.2 and 5.1.4. The information is ultimately sourced from the RC, but FAC-014-3, Requirement R5, Parts 5.1, 5.2, and subparts requires the RC to communicate the relevant information to the PC, who, in turn, can communicate the information to the applicable GO and TO as required by PRC-002-2, Requirement R5, Parts 5.1.2 and 5.1.4. FAC-014-3 R5. Each Reliability Coordinator shall provide:

		5.1. Each Planning Coordinator within its RC Area, SOLs for its RC Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies); and, 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). While subparts 5.1.2 and 5.1.4 of PRC-002-2 would benefit from a revision in response to the retirement of FAC-010, the need for such a revision does not rise to the level of creating a reliability gap if FAC-010 is retired prior to the time these requirements can be changed. **Recommendations:** It is recommended that this standard be modified at some point in the future to update the designation of the Responsible Entities defined in the Standard. In the absence of this change, however, the currently defined Responsible Entities are capable of providing the necessary information through the mechanisms described above.
PRC-023-4	**Attachment B** - Criteria Section:	Direct reference to FAC-010 made in this attachment.

	If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit… B2. The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.	Attachment B sets the applicability of facilities operated below 200 kV (similar to FAC-003). These items reference PRC-023-4, Requirement R6, to which Attachment B is applicable. The language in part B2 of Attachment B of PRC-023-4 specifically addresses IROLs determined in the planning horizon pursuant to FAC-010-3; however, IROLs are established by the RC, and the Facilities critical to the derivation of the IROL are communicated to the GOs and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." Accordingly, the GO and the TO are able to use the IROL information provided by the Reliability Coordinator. While part B2 of Attachment B for PRC-023-4 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired prior to the revision of these subparts given the above requirements for the RC. **Recommendations:** Revise Attachment B of PRC-023-4 in response to the retirement of FAC-010-3 to eliminate the references to FAC-10, PC's determining IROLs and IROLs in the Planning Horizon for identification of circuits as a monitored Facility of an Interconnection Reliability Operating Limit (IROL).

		A future team should consider the appropriateness for the circuits identified as applicable to Attachment B of PRC-023-4 to include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
PRC-026-1	R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: Criteria: 1. Generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). 2. An Element that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an angular stability constraint. *{[1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.}*	Direct reference is made to the PC's SOL Methodology. Footnote 1 on page 3 of 84 references FAC-014-2, R3. Similar to the reference identified in Requirement R5, Part 5.1.2 of PRC-002-2, Requirement R1 of PRC-026-1 references the identification of facilities that are sensitive to angular stability constraints. Stability-related SOLs are communicated to the Planning Coordinator through FAC-014-3, Requirement R5, Parts 5.1 and, 5.2: R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator within its RC Area, SOLs for its RC Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL;

		5.2.4. The associated Contingency(ies); and, 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). With this information, the PC can communicate the necessary SOL information to the applicable GO and TO as required by PRC-026-1, Requirement R1. While Criteria 1 and 2 of PRC-026-1 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired prior to the revision of these criteria given the above requirement for the RC. **Recommendations:** Revise PRC-026-1, Requirement R1 in response to the retirement of FAC-010-3 to eliminate the term, "Planning Coordinator's Methodology" which references FAC-10 and remove the reference to SOLs identified by the PC. A future team should consider that the PRC-026 R1 criteria reference Elements associated with angular stability as identified in the PC or TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
TOP standards		No Action Required
TPL standards		No Action Required
VAR standards		No Action Required

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2017 – November 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board adoption	May 2018

A. Introduction

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

2. **Number:** FAC-011-~~3~~4

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** ~~——~~ See Implementation Plan for ~~the Revised Definition of "Remedial Action Scheme".~~Project 2015-09.

B. Requirements and Measures

R1. ~~The~~Each Reliability Coordinator shall have a ~~documented~~ methodology for ~~use in developing~~establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area. ~~This~~*[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology.

~~R1.~~R2. Each Reliability Coordinator shall~~:~~ include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**1.1.** Be applicable for developing SOLs used in the operations horizon.~~

~~**1.2.** State that SOLs shall not exceed associated Facility Ratings.~~

M2. ~~Include a description of how to identify the subset of SOLs that qualify~~Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~1.3.~~ Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as ~~IROLs.~~

3.1. ~~The~~ specified in the Reliability Coordinator's SOL Methodology ~~shall include a requirement that SOLs provide BES~~ ;

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

3.3. Require that System Voltage Limits are higher than in-service under voltage load shedding (UVLS) relay settings;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Address the use of common System Voltage Limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area;

3.6. Address coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and

3.7. Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~1.4.~~4.1. Specify stability performance ~~consistent with~~ criteria, including any margins applied. The criteria shall include the following:

4.1.1. ~~In the pre-contingency~~ steady-state~~, the BES shall demonstrate~~ voltage stability;

4.1.2. transient~~, dynamic and~~ voltage response;

4.1.3. angular stability; ~~all Facilities shall be within their Facility Ratings and within their thermal, voltage and~~ and

4.1.4. System damping.

4.2. Require that stability limits~~. In~~ are established to meet the ~~determination of SOLs,~~criteria specified in Part 4.1 for the ~~BES condition used shall reflect current or expected system~~Contingencies identified in Requirement R5.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.

~~1.5.~~4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions ~~and shall reflect~~ including any changes to ~~system~~System topology such as Facility outages~~.~~ ;

~~**1.6.** Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.~~

4.5. ~~Single line to~~ Describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions; the planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The method shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. Loss of any of the following either by single phase to ground or ~~3-~~three phase Fault (whichever is more severe~~),~~) with ~~Normal Clearing, on any Faulted~~ normal clearing, or without a Fault:

- generator~~, line, ~~;
- transmission circuit;
- transformer~~, or ~~;
- shunt device~~.~~; or

~~**1.6.1.** Loss of any generator, line, transformer, or shunt device without a Fault.~~

- ~~Single~~single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

~~**1.7.** In determining the system's response to a~~ Any additional types of single Contingency~~, the following shall be acceptable:~~

~~[1] The Contingencies identified in FAC-011-R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.~~

~~**1.7.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.~~

~~**1.7.2.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~

~~**1.7.3.** System reconfiguration through manual or automatic control or protection actions.~~

~~**1.8.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.~~

~~**R2.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:~~

~~**2.1.** Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)~~

~~**2.2.** Selection of applicable Contingencies~~

5.2. ~~A process for determining which of the~~ events identified for use in determining stability limits~~ associated with the list~~, or for use in performing OPAs and RTAs.

5.3. Any types of multiple ~~contingencies (~~Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

~~**2.3.**~~**5.4.** The method for considering the Contingency events provided by the Planning ~~Authority~~Coordinator in accordance with FAC-~~014~~015-1, Requirement ~~6) are applicable for use in the operating horizon given the actual or expected system conditions.~~ R6 to identify the Contingencies for use in determining stability limits.

~~**2.3.1.** This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.~~

~~**2.4.** Level of detail of system models used to determine SOLs.~~

~~**2.5.** Allowed uses of Remedial Action Schemes.~~

~~**2.6.** Anticipated transmission system configuration, generation dispatch and Load level~~

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include in its SOL Methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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

~~**2.7.**~~**6.2.** Criteria for determining when violating a SOL qualifies as an ~~Interconnection Reliability Operating Limit (~~IROL~~)~~ and criteria for developing any associated IROL T_V.

M6. ~~The~~ Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its Reliability Coordinator(s). The method shall address the periodicity of SOL communication. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R7.

~~**R3.**~~**R8.** Each Reliability Coordinator shall ~~issue~~provide its SOL Methodology and any changes to ~~that methodology,~~the SOL Methodology prior to the effective date of the SOL Methodology, to ~~the effectiveness of the Methodology or of a change to the Methodology, to all of the following: :~~ *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~**3.1.**~~**8.1.** Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that ~~indicated~~requests and indicates it has a reliability-related need ~~for the methodology.~~;

8.2. Each Planning ~~Authority~~Coordinator and Transmission Planner that ~~models~~is responsible for planning any portion of the Reliability ~~Coordinator's~~Coordinator Area;

~~**3.2.**~~**8.3.** Each Transmission Operator within its Reliability Coordinator Area.

~~**3.3.** Each Transmission Operator~~ Acceptable evidence that ~~operates in~~ the Reliability Coordinator ~~Area.~~

~~C. Measures~~

~~**M1.** The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.~~

~~**M2.**~~**M8.** ~~The Reliability Coordinator shall have evidence it issued~~provided its SOL Methodology~~, and any changes to that methodology, including the date they were issued, in accordance~~ to the entities identified in Requirement R8 may include, but is

not limited to, dated electronic or hard copy documentation such as emails with Requirement 4. receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

D.C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring ResponsibilityEnforcement Authority:
Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

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

1.3.1.2. Evidence Retention:
The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site auditThe following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by theits Compliance Monitor or within 15

business daysEnforcement Authority to retain specific evidence for a longer period of a requesttime as part of an investigation upon complaint:.

1.4.1 SOL Methodology.

1.4.2 Superseded portionsThe Reliability Coordinator shall keep data or evidence of its SOL Methodology that had been made within the past 12 months.

1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

- **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4with Requirements R1 through R3.7 and E1R8 for the current year plus the previous 12 calendar months. .

2.2. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.2.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.2.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.2.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.3. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels~~:~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.
~~R1~~**R2.**	~~Not applicable.~~ N/A	~~The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2~~N/A	The Reliability Coordinator ~~has a documented~~ included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations, but the method did not address the use ~~in developing SOLs within~~of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area~~, but it does not address R1.3.~~	The Reliability Coordinator ~~has a documented~~ did not include in its SOL Methodology the method for ~~use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1~~Transmission Operators to determine the applicable owner-provided Facility Ratings to be used~~.~~ ~~OR~~ ~~The Reliability Coordinator has no documented SOL Methodology for use~~ in ~~developing SOLs within its Reliability Coordinator Area.~~operations.

~~R2~~**R3.**	The Reliability Coordinator~~'s~~ failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology ~~requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)~~ .	~~Not applicable.~~The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator~~'s~~ failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology ~~requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)~~.	~~The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)~~The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL Methodology.
~~R3~~ **R4.**	The Reliability ~~Coordinator's~~Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but one of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's~~Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but two of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's~~Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but three of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's SOL Methodology is missing a description of~~Coordinator failed to incorporate four or more of the ~~following: R3.1 through R3.7~~Parts of Requirement R4 into its SOL Methodology.
R5.	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of

				Requirement R5 into its SOL Methodology.
~~R3.6~~**R6.**	N/A	N/A	~~N/A~~The Reliability Coordinator failed to include Part 6.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (criteria for developing any associated IROL T_V) in its SOL Methodology.	~~N/A~~The Reliability Coordinator failed to include Parts 6.1 and 6.2 in its SOL Methodology.
R7.	N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the

			Transmission Operator established.	periodicity of SOL communication.
~~R4~~**R8.**	The Reliability Coordinator ~~failed to issue~~provided its new or revised SOL Methodology ~~and/or one or more changes to that methodology to one of the required entities specified~~to a requesting Reliability Coordinator in ~~R4.1, R4.2, and R4.3.~~ ~~OR~~ ~~For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change,~~accordance with Part 8.4 but was ~~provided to all the required entities no more~~late by less than or equal to 10 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator ~~failed to issue~~ provided its new or revised SOL Methodology ~~and/or one or more changes to that methodology to two of the required entities specified~~to a requesting Reliability Coordinator in ~~R4.1, R4.2, and R4.3.~~ ~~OR~~ ~~For a change in methodology, the changed methodology~~ accordance with Part 8.4, but was ~~provided to one or more of the required entities~~late by more than 10 calendar days ~~after the effectiveness of the change, but~~ but less than or equal to 20 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator failed to ~~issue~~provide its new or revised SOL Methodology ~~and/or~~to one ~~or more changes to that methodology to three~~ of the ~~required entities~~parties specified in ~~R4~~Parts 8.1~~, R4.2, and R4~~ through 8.3. OR ~~For a change in methodology, the changed methodology was~~ The Reliability Coordinator provided ~~to one or more of required entities~~its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 20 calendar days ~~after the effectiveness of the change, but~~ but less than or equal ~~to30~~to 30 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator failed to ~~issue~~provide its new or revised SOL Methodology ~~and/or one or more changes~~ to ~~that methodology to four~~two or more of the ~~required entities~~parties specified in ~~R4~~Parts 8.1~~, R4.2, and R4~~ through 8.3. OR ~~For a change in methodology, the changed methodology was provided~~ The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the ~~required entities more than30~~parties specified in Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology. OR The Reliability Coordinator provided its new or revised SOL Methodology to a

				requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 30 calendar days~~ after the effectiveness of the change~~. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4.

~~E.~~D. Regional ~~Differences~~Variances

~~3.~~ The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

~~3.1.~~ As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

~~3.1.1~~ Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

~~3.1.2~~ A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

~~3.1.3~~ Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

~~3.1.4~~ The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

~~3.1.5~~ A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

~~3.1.6~~ A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

~~3.1.7~~ The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

~~3.2.~~ SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

~~3.2.1~~ All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

~~3.2.2~~ Cascading does not occur.

~~3.2.3~~ Uncontrolled separation of the system does not occur.

~~**3.2.4** The system demonstrates transient, dynamic and voltage stability.~~

~~**3.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.~~

~~**3.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.~~

~~**3.2.7** To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.~~

~~**3.3.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:~~

~~**3.3.1** Cascading does not occur.~~

~~**3.4.** The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.~~

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
~~3~~4	~~November 19, 2015~~	~~FERC Order issued approving FAC-011-3. Docket No. RM15-13-000.~~Project 2015-09 – Adopt revisions to standard.	Revisions

Mapping Document

Project 2015-09 Establish and Communicate System Operating Limits

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:	FAC-011-4, Requirement R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.	No change.
FAC-011-3, Requirement R1, R1.1. [This SOL Methodology shall] Be applicable for developing SOLs used in the operations horizon.	This requirement was removed.	The stated purpose of FAC-011-4 is "To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies." The title of FAC-011-4 is "System Operating Limits Methodology for the Operations Horizon". Therefore, every requirement in FAC-011-4 is intended for developing SOLs used in the operations horizon. Accordingly, there is no reliability-

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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		related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL Methodology is applicable for developing SOLs used in the operations horizon.
FAC-011-3, Requirement R1, R1.2. [This SOL Methodology shall] State that SOLs shall not exceed associated Facility Ratings.	This requirement is addressed in proposed FAC-011-4 Requirement R2 in conjunction with the definitions for Operational Planning Analysis and Real-time Assessment in the NERC Glossary of Terms. FAC-011-4 Requirement R2: Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for*	Facility Ratings to be used in operations as SOLs is addressed through FAC-011-4, Requirement R2. Facility Ratings that are determined per Requirement R2 are a required input for Operational Planning Analyses (OPA) and Real-time Assessments (RTA) per the definitions, and therefore address the analysis of system performance with respect to Facility Ratings. Facility Rating exceedances are determined through OPAs and RTAs.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through*	

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	internal systems or through third-party services.)"	
FAC-011-3, Requirement R1, R1.3. [This SOL Methodology shall] Include a description of how to identify the subset of SOLs that qualify as IROLs.	FAC-011-4, Requirement R6 and Part 6.1. R6. Each Reliability Coordinator shall include in its SOL Methodology 6.1. A description of how to identify the subset of SOLs that qualify as IROLs.	The language from the approved standard was maintained in the proposed FAC-011-4.
FAC-011-3, Requirements R2, R2.1 and R2.2. R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.	These requirements are addressed in: 1. TOP and IRO requirements for TOPs and RCs to perform OPAs, to develop Operating Plans for SOL exceedances identified in those OPAs, to perform RTAs, and to implement Operating Plans to address SOL exceedances identified in those RTAs. 2. The definition of OPA and RTA 3. FAC-011-4, Requirement R4 addresses the establishment of stability limits and the associated performance requirements. 4. FAC-011-4 Requirement R6 and its Parts relating to IROLs.	"BES performance" as stated in FAC-011-3 Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). If SOL exceedance is occurring, the system is not performing reliably. Per the Transmission Operator (TOP) standards, SOL exceedance triggers the development and

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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R2.2. Following the single Contingencies identified in Requirement R2, R2.2.1 - R2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	5. The definition of IROL and the TOP and IRO standards that address operation within IROLs. TOP-002-4, Requirement R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). TOP-001-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. TOP-001-4, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. TOP-001-4, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL	implementation of an Operating Plan to address that SOL exceedance. The items in approved FAC-011-3, Requirement R2 and its sub-requirements are addressed through the related TOP standards that reference SOL exceedance. 1. Per TOP-002-4, Requirement R1, TOPs have OPAs to identify SOL exceedances. 2. Per TOP-002-4, Requirement R2, TOPs develop Operating Plans for SOL exceedances identified in the OPA. 3. Per TOP-001-3, Requirement R13, TOPs perform RTAs at least once every 30 minutes to identify SOL exceedances. 4. Per TOP-001-3, Requirement R14, TOPs implement Operating Plans to mitigate SOL exceedances. 5. Per IRO-008-2, Requirement R1, RCs perform OPAs to identify SOL and IROL exceedances.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	exceedance identified as part of its Real-time monitoring or Real-time Assessment. IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. IRO-008-2, Requirement R4: Each Reliability Coordinator shall ensure that a Real-time	6. Per IRO-008-2, Requirement R2, RCs develop coordinated Operating Plans for SOL and IROL exceedances identified in its OPA. 7. Per IRO-008-2, Requirement R4, RCs perform RTAs at least once every 30 minutes to identify SOL and IROL exceedances. 8. Per IRO-008-2, Requirement R5, RCs notify TOPs and BAs of SOL or IROL exceedances identified in its RTA. The portion of FAC-011-3, Requirement R2, R2.1 that states *"In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages"* is addressed specifically by FAC-011-4 Requirement R4, Part 4.4 which requires that System conditions including any changes to System topology such as Facility outages are to be included as part of the process for determining stability limits. While stability

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Assessment is performed at least once every 30 minutes. IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status*	limits are frequently dependent on system conditions and Facility outages, Facility Ratings and System Voltage Limits are not dependent on system conditions and Facility outages. However, system conditions and topology changes such as Facility outages are critical for determining whether or not Facility Ratings and System Voltage Limits are being exceeded for the pre- or post-Contingency state, which is accomplished through performing OPAs and RTAs that address expected and actual system conditions and Facility outages for the pre- and post-Contingency state. Regarding the stability portions of Requirement R2, R2.1 and R2.2: FAC-011-4, Requirement R4 improve reliability by requiring the RC's SOL Methodology to address several stability-related phenomena and associated performance criteria in its SOL Methodology, as seen in Requirement R4, Part 4.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)"*	Requirement R4, Part 4.2 requires the RC's SOL Methodology to require that stability limits be established to meet those performance requirements. Furthermore, Requirement R4, Part 4.6 requires the RC's SOL Methodology to specify how the RC establishes stability limits when there is an impact to more than one TOP in its Reliability Coordinator Area RC's SOL Methodology. Requirement R4 works together with FAC-014-3, Requirement R2 which requires TOPs to establish SOLs in accordance with the RC's SOL Methodology and with FAC-014-3, Requirement R4 which requires the RC to establish stability limits that impact more than one TOP in its RC Area. Instability is also addressed through FAC-011-4, Requirement R6 which requires the RC's SOL Methodology contain a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs), and through FAC-014-3, Requirement R1 which requires the

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	FAC-011-4 Requirement R4: Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. angular stability; 4.1.4. System damping. 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.	RC to establish IROLs in accordance with its SOL Methodology. IRO-009-2, Requirement R3 requires the RC to act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. Additionally, TOP-001-3, Requirement R12 requires that the TOP not operate outside any identified IROL for a continuous duration exceeding its associated IROL T_V.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions. IROL is defined in the NERC Glossary of Terms as – *A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.*	

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	FAC-011-4, Requirement R6: Each Reliability Coordinator shall include in its SOL Methodology: 6.1. A description of how to identify the subset of SOLs that qualify as IROLs. 6.2. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V. FAC-014-3, Requirement R1: Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). IRO-009-2, Requirement R3: Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an	

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	IROL exceedance is mitigated within the IROL's T_V, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. TOP-001-3, Requirement R12: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_V.	
FAC-011-3, Requirement R2, sub-requirements R2.2.1, R2.2.2, and R2.2.3 R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	FAC-011-4, Requirement R5, Part 5.1.1 Loss of any of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device; • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	The requirements in approved FAC-011-3 were consolidated into a single requirement in proposed FAC-011-4.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and Requirement R2.4. R2.3 In determining the system's response to a single Contingency, the following shall be acceptable: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies R2.3.3. System reconfiguration through manual or automatic control or protection actions. R2.4 To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the	The reliability issues denoted in FAC-011-3 Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and R2.4 represent a combination of issues that are relevant to the establishment of SOLs and those that are relevant to "how the system is to be operated." The issues that pertain to the establishment of SOLs are addressed through FAC-011-4 Requirement R4 : R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. angular stability; 4.1.4. System damping.	Requirement R2, R2.3 describes an acceptable System response to single Contingencies. These requirements are sub-requirements of Requirement R2, which addresses the establishment of SOLs that "provide a certain level of BES performance". "BES performance" as stated in FAC-011-3, Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). If SOL exceedance is occurring, the system is not performing reliably. Per the TOP and IRO standards, RTAs must be performed at least once every 30 minutes. Accordingly, each new operating state is "studied" at least once every 30 minutes. Additionally, per the TOP

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transmission system, and the transmission system topology.	4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area. 4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other	standards, SOL exceedance triggers the development and implementation of an Operating Plan to address that SOL exceedance. Insofar as the issues in FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to the establishment of SOLs, automatic control actions relevant to the establishment of stability limits are addressed in FAC-011-4 Requirement R4, Part 4.6 which requires the SOL Methodology to describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions as part of stability limit establishment. Accordingly, any RAS or automatic mitigation scheme (which includes those that interrupt customers or reconfigure the system) are required to be reflected in the establishment of stability limits per Requirement R4, Part 4.6. Furthermore, per Requirement R4, Part 4.4, stability limits are required to take into consideration the configuration of the system, which may include any necessary

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	automatic post-Contingency mitigation actions. The issues that are more centric to "how the system is to be operated" are more appropriately addressed in the development and implementation of Operating Plans as denoted in the following standards: 1. TOP-002-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. 2. TOP-002-4, Requirement R3: Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). 3. TOP-002-4, Requirement R6: Each Transmission Operator shall provide	manual actions taken by the System Operator to configure the system in a manner that supports the use of a given stability limit. However, insofar as FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to "how the system is to be operated", the operational decisions related to customer interruption and system reconfiguration are governed by the Operating Plan, if such actions are necessary to address SOL exceedance. The need for making system adjustments to prepare for the next Contingency is standard operational practice and does not need to be specified or required by the Reliability standards. Any such actions related to the interruption of customers, reconfiguration of the system, or operational preparations for the next Contingency are expected to be included in an Operating Plan, if such actions are required by System Operators to address SOL exceedances.

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	its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. 4. TOP-012-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. 5. IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. 6. IRO-008-2, Requirement R3: Each Reliability Coordinator shall notify	In the current body of TOP and IRO reliability standards, the Operating Plan is the mechanism for addressing SOL exceedances. The mitigation actions that System Operators take to prevent or address SOL exceedances are expected to be contained within the Operating Plan. TOPs need to have the flexibility in their Operating Plan to address the wide-ranging operational issues they may encounter. There is no reliability need for reliability standards to provide such highly prescriptive requirements which specify how TOPs are to operate the system. Because the development and implementation of Operating Plans is addressed in the current body of reliability standards, reliability is not compromised by the removal of FAC-011-3, Requirement R2, R2.3 and R2.4. Any concepts in this section may need to be retained are better suited in a Reliability Guideline (e.g., Reliability Guideline for the development of Operating Plans) rather

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	impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). 7. IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.	than a NERC Reliability Standard requirement.
FAC-011-3, Requirement R3, R3.1 R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including	FAC-011-3, Requirement R3, R3.1 and R3.4 both address the study model. These two requirements are addressed with the single requirement in proposed FAC-011-4, Requirement R4, Part 4.5. Facility Ratings are created and provided through FAC-008 and further examined

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R3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	through FAC-011-4, Requirement R2. System Voltage Limits are created per FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model. As a result, no study model reference is needed in FAC-011-4 for Facility Ratings or System Voltage Limits. However, for those RCs or TOPs that determine stability limits, a study model is needed to perform the "study". Therefore, the level of detail of the study model falls under the requirement associated with establishing stability limits (R4). FAC-011-4, Requirement R4, Part 4.5 affords the RC with the flexibility to the extent of the modeling area (including other RC areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide-area or inter-area instability). Part 4.5 acknowledges that some types of localized stability issues do not require a model of

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		the entire RC area to establish certain types of stability limits.
FAC-011-3, Requirement R3, R3.2 R3.2 [The RC's SOL Methodology shall include] Selection of applicable Contingencies	FAC-011-4, Requirement R5 R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include: 5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs: 5.1.1. Loss of any of the following, either by single phase to ground or three phase Fault (whichever is more severe) with normal clearing, or without a Fault: • generator; • transmission circuit; • transformer;	All requirements regarding Contingencies are consolidated and addressed in proposed FAC-011-4, Requirement R5.

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	• shunt device; • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system. 5.2. Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs. 5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs. 5.4. The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits.	
FAC-011-3, Requirement R3, R3.3 and R3.3.1. R3.3 [The RC's SOL Methodology shall include] A process for determining which of the stability limits associated with the list of	FAC-011-4, Requirement R5, Part 5.4 R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and	FAC-011-4, Requirement R5, Part 5.4 and FAC-015-1 Requirement R6 address the reliability objective in FAC-011-3, Requirement R3, R3.3.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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multiple contingencies (provided by the Planning Authority in accordance with FAC-014, Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.	multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include: 5.4. The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits. FAC-015-1 Requirement R6: R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include:	In FAC-015-1, Requirement R6, the Planning Coordinator is required to identify and communicate any instability, Cascading, or uncontrolled separation, as well as the related information contained in the Parts of Requirement R6, to the RC and associated TOPs. Once the RC receives this information, the RC then applies the method required by FAC-011-4, Requirement R5, Part 5.4 for considering those Contingencies for use in determining stability limits. These requirements collectively address the reliability objectives of FAC-011-3, Requirement R3, R3.1.

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	6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	
FAC-011-3, Requirement 3, R3.4. R3.4 [The RC's SOL Methodology shall include] Level of detail of system models used to determine SOLs.	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL Methodology the method	Reference the explanation provided for FAC-011-3, Requirement R3, R3.1.

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	for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	
FAC-011-3, Requirement R3, R3.5. R3.5 [The RC's SOL Methodology shall include] Allowed uses of Remedial Action Schemes.	FAC-011-4, Requirement R4, Part 4.6 R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions[1]. Footnote 1 states "The planned use of underfrequency load-shedding (UFLS) is not allowed in the establishment of stability limits."	FAC-011-3, Requirement R3, R3.5 was carried over into FAC-011-4, Requirement R4, Part 4.6. The requirement has been clarified by including other automatic mitigation actions that are not a RAS, for example UVLS.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R3, R3.6. R3.6 [The RC's SOL Methodology shall include] Anticipated transmission system configuration, generation dispatch and Load level	FAC-011-4, Requirement R4, Part 4.4: R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; TOP-002-4, Requirement R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating	The requirements in FAC-011-3, Requirement R3, R3.6 are addressed in proposed FAC-011-4, Requirement R4, Part 4.4. Part 4.4 was included as a Part to Requirement R4 because the information is relevant to the establishment of stability limits. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2, and System Voltage Limits are created through FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model that requires inclusion of the items in FAC-011-3, Requirement R3, R3.6. Additionally, TOP-002-4, Requirement R1 and IRO-008-2, Requirement R1 require the TOP and the RC respectively to have/perform an OPA. Per the definition of OPA, the OPA shall reflect applicable inputs which include the

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	Reliability Limits (IROLs) within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"*	items required by FAC-011-3, Requirement R3, R3.6. Accordingly, when stability limits include the information required in Requirement R4, and the TOPs and RCs perform their required OPAs, the information in FAC-011-3, Requirement R3, R3.6 is inherently addressed.
FAC-011-3, Requirement R3, R3.7. R3.7 [The RC's SOL Methodology shall include] Criteria for determining when violating a SOL qualifies as an Interconnection Reliability	FAC-011-4, Requirement R6, Part 6.2 R6.2 Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and	The reliability objective of FAC-011-3, Requirement R3, R3.7 was carried over into FAC-011-4, Requirement R6, Part 6.2.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Operating Limit (IROL) and criteria for developing any associated IROL T_V.	criteria for developing any associated IROL T_V.	
FAC-011-3, Requirement R4 and Requirement R4.1: R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	FAC-011-4, Requirement R8, Parts 8.1 and 8.4: R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.1. Each adjacent Reliability Coordinator within its Interconnection prior to the effective date of the SOL Methodology; 8.4. Each requesting Reliability Coordinator that indicates a reliability-related need and is not considered adjacent in Part 8.1, within 30 calendar days of receiving the request.	The reliability objective of FAC-011-3, Requirement R4 was carried over to FAC-011-4, Requirement R8, Parts 8.1 and 8.4 Clarifications were made in Part 8.1 that adjacent RCs include those within an Interconnection. This was added to clarify the intent of adjacent RCs for the purposes of communicating SOL Methodologies. These adjacent RCs are required to receive the SOL Methodology prior to the effective date of the Methodology because they can be directly impacted by it. Non-adjacent RCs, which are addressed in Part 8.4, do not require communication of the SOL Methodology prior to its effective date because these RCs are less likely to be directly impacted; however, provisions are made with Part 8.4 for non-adjacent RCs to obtain the SOL Methodology within 30 days of the request if they indicate a reliability-related need for it.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R4, R4.2 R4.2 [communicate the SOL Methodology to] Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	FAC-011-4, Requirement R8, Part 8.2 R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.2. Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The language was changed to better reflect the intent of the requirement. The requirement is intended to addresses PCs and TPs that are responsible for planning within the RC Area.
FAC-011-3, Requirement R4, R4.3 R4.3 [communicate the SOL Methodology to] Each Transmission Operator that operates in the Reliability Coordinator Area.	FAC-011-4, Requirement R8, Part 8.3 R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.3. Each Transmission Operator within its Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The reliability objective of FAC-011-3, Requirement R4, R4.3 was carried over to FAC-011-4, Requirement R8, Part 8.3.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rationale for FAC-011-4

September 2017

Requirement R1

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

Rationale R1

The three subparts in Requirement R1 in currently-effective Reliability Standard FAC-011-3 are either not necessary for reliability, or they are addressed through other mechanisms in FAC-011-4 and therefore are not included as part of Requirement R1.

Requirement R1.1 in currently-effective FAC-011-3 requires that the SOL Methodology shall be applicable for developing SOLs used in the operations horizon. The revised Requirement R1 is applicable to the Operations Planning Time Horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL Methodology is applicable for developing SOLs used in the operations horizon. Additionally, the purpose of the standard references SOLs used in the reliable operation of the BES.

Requirement R1.2 in currently-effective FAC-011-3 requires that the SOL Methodology state that SOLs shall not exceed associated Facility Ratings. Facility Ratings to be used in operations as System Operating Limits (SOLs) are addressed through FAC-011-4 Requirement R2 and therefore is not addressed as a subpart of R1.

Requirement R1.3 in currently-effective FAC-011-3 requires that the SOL Methodology include a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs). This language is preserved in Requirement R6.

Requirement R2

Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.

Rationale R2

The reliability objectives of Requirement R2 are 1) to ensure that the owner-provided Facility Ratings that are selected for use in operations are determined in accordance with the RC's SOL Methodology, and 2) to ensure the consistent use of applicable Facility Ratings between RCs and their Transmission Operators (TOP). For example, if a Transmission Owner (TO) provides three levels of Facility Ratings pursuant to Reliability Standard FAC-008-3, and another TO provides five

levels of ratings, the RC will establish the method for the TOPs to determine which of those Facility Ratings will be utilized in common with the TOP and the RC for monitoring and assessments.

The intent of Requirement R2 is not to change, limit, or modify Facility Ratings determined by the equipment owner. The equipment owner is still responsible for determining the Facility Ratings per FAC-008. The intent is to use those owner-provided Facility Ratings in a consistent manner between the TOP and RC during operations.

Requirement R3

Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

- **3.1** Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as specified in the Reliability Coordinator's SOL Methodology;
- **3.2** Require that System Voltage Limits respect the Facility voltage Ratings;
- **3.3** Require that System Voltage Limits are higher than in-service undervoltage load shedding (UVLS) relay settings;
- **3.4** Identify the lowest allowable System Voltage Limit;
- **3.5** Require the use of common System Voltage Limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area;
- **3.6** Require coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area;
- **3.7** Require coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

Rationale R3

System Voltage Limits (SVLs) are intended to provide reliable pre- and post-contingency System performance for operations within a Reliability Coordinator Area and across neighboring Reliability Coordinator Areas. The proposed definition of System Voltage Limits includes normal and emergency voltage limits, and can also include time-based voltage limits, depending on what the RC requires. It is expected that the RC would require a set of System Voltage Limits to cover the entire BES system within its Reliability Coordinator Area for facility-based voltage limits, voltage instability, voltage collapse and misactuation of relay elements.

Both high and low limits are required. High limits tend to be associated with equipment/facility limitations. Low limits are often used to prevent phenomena associated with low voltages such as system instability, voltage collapse, and potential misactuation of relay elements. Identifying the set of "System Voltage Limits", both high and low, assures that all voltage limits associated with a particular bus or station, or the equipment connected to it, have been considered and the most limiting are used.

While all BES buses/stations have equipment related voltage ratings, there may be reasons that certain buses/stations do not require a System Voltage limit. Part 3.1 allows RCs to identify certain buses/stations that may be excluded from having an associated System Voltage Limit. These exempt buses/stations should be identified in the RC's SOL Methodology with appropriate reasoning. The identification of such buses/stations could be documented by citing the type of buses/stations (based on voltage level or area of the System) as opposed to a more detailed list of individual buses/stations which are exempt.

Buses or stations may not require System Voltage Limits when the voltage at the station has no material impact on System performance and associated SOLs. For example, System Voltage Limits at neighboring/nearby stations may be sufficient to protect the facilities from high voltage, and the System from instability, voltage collapse, and misactuation of relay elements.

Parts 3.5-3.7 identifies the RC as the entity responsible for developing the overall method for TOPs and RCs to determine and coordinate System Voltage Limits in their areas and neighboring areas.

Part 3.2 provides that in establishing System Voltage Limits, the SOL Methodology shall respect any Facility voltage Ratings established by the Generation Owner or TO under FAC-008. Recognizing that voltage limits are difficult to reflect by facility, the System Voltage Limits provided for stations/buses should reflect any Facility voltage Ratings for facilities that terminate at or are adjacent to the stations/buses with System Voltage Limits.

FERC Order No. 818 issued November 19, 2015, states that UVLS should not be triggered for an N-1 Contingency. As such, under Part 3.3, the SOL Methodology shall ensure System Voltage Limits are set above all UVLS settings to avoid UVLS operation following N-1 Contingencies.

Requirement R4

Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall:

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

- **4.1.1** steady-state voltage stability;
- **4.1.2** transient voltage response;
- **4.1.3** angular stability;
- **4.1.4** System damping;

4.2 Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5;

4.3 Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area;

4.4 Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5 Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6 Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions[1].

Rationale R4

Reliability Standard FAC-011-3 currently requires the System to demonstrate transient, dynamic and voltage stability for both pre- and post-contingent states, but does not provide specifics. By requiring specific stability criteria within the SOL Methodology, the standard is improved and provides greater clarity and uniformity on practices across the industry. The set of commonly used stability criteria specified in Requirement R4 Part 4.1 is based upon information provided by standard drafting team members and observers, including many RCs and TOPs. Industry input from areas with significant experience managing stability issues led to the inclusion of system damping.

Also included in Part 4.1 is language requiring the SOL Methodology to include descriptions of how margins are applied. This language was added to explicitly capture the practices in use by RCs for off-line or on-line calculated stability limits, including any margin used in the application of the stability limits. It is left to the RC what type of margin to use (a percentage of the limit or a fixed MW value, for example), if it uses one at all.

Requirement R4 Part 4.2 provides the link to the Contingencies which must be respected in operations, which are unchanged from the current standard. In response to industry comments, Contingency specifications were moved to a separate requirement.

Requirement R4 Part 4.3 was introduced to preclude ambiguity in the resolution of stability limits when multiple TOPs within an RC's footprint are impacted. For example, this requirement may be met by providing language in the SOL Methodology describing which TOP (or identifying that the RC) has the responsibility to determine stability SOLs impacting multiple TOPs, and could also determine how to choose between stability limits derived by multiple TOPs for the same stability limit exceedance.

Requirement R4 Parts 4.4, 4.5 and 4.6 require that the SOL Methodology provide a description of the key parameters that must be considered and monitored when performing analyses to determine the stability limits. The intent of these parts is to help ensure that the SOL Methodology provides guidance such that the process/method used by the RC to determine stability limits may be repeated, successfully, by anyone reading the SOL Methodology. For example, the SOL Methodology could state that stability limits will be determined for any combination of all facilities in and single facility out

[1] The planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.

conditions, for all valid transfer conditions for the highest allowable thermal transfer condition (i.e. winter ratings), plus a flow margin of 10%, to account for potential emergency transfer conditions. This level of detail would allow TOPs and other entities to consistently duplicate results from study to study. Part 4.5 combines FAC-011-3 Requirements R3.1 and R3.4 into a single part while providing flexibility to the extent of the Reliability Coordinator Area (including other Reliability Coordinator Areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide area or inter area instability). By recognizing that some types of localized stability issues do not require entire Reliability Coordinator Area modeling to establish a stability limit, this revision aligns with and promotes the ability to monitor these localized areas with real time stability analysis tools.

Requirement 4 Part 4.4 is specifically intended to address the need for the SOL Methodology to identify the method for ensuring stability limits are "valid" (i.e. provide stable operations pre- and post-Contingency) for the Operational Planning Analysis (OPA) and Real-time Assessments (RTA) for which they will be used. Since stability limits may vary based on the system topology, load, generation dispatch, etc., and the current definitions for OPA and RTA include "An evaluation of … system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for ….operations", the stability limits used in OPA/RTA should be "valid" for those system conditions.

As described within PRC-006-2 in alignment with FERC Order No. 763, underfrequency load shedding (UFLS) are designed "to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures." In the establishment of stability limits under Requirement R4 Part 4.6, UFLS programs are expressly prohibited from being considered as an acceptable post-Contingency mitigation action in order to preserve the intended availability of UFLS as a "last resort system preservation measure".

Requirement R5

Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include:

5.1 The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

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

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

5.2 Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.4 The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits.

Rationale R5

Requirement R5 combines both the requirements for single Contingencies (formerly in Requirement R2.2 of FAC-011-3) and for multiple Contingencies (formerly in Requirement R3.3 of FAC-011-3) for ease of interpretation.

Furthermore, Requirement R5 continues to maintain the flexibility that existed in Requirement R2.2 and Requirement R3.3 for each RC to determine which additional single and multiple Contingencies to respect given the uniqueness of their system. Through both the feedback received as a result of the July 2016 informal posting and the May 2016 technical conference it was evident that both the drafting team and industry agree that sufficient flexibility is required for each RC to determine its own methodology for addressing Contingencies other than single Contingencies.

Requirement R5 mandates that the RC specify which types of Contingencies (both single and multiple) are used for determining stability limits as well as those used in checking for all types of SOL exceedances in OPAs and RTAs (thermal, voltage and stability limits). The SOL Methodology is the best place to communicate which Contingencies the RC is respecting in their footprint such that all TOPs and any neighboring RCs understand one another's internal and interconnection-related reliability objectives.

Requirement R5 Part 5.1.1 identifies the types of single Contingency events that at a minimum must be used for stability limit analysis and for performing OPAs and RTAs. However, other types of single Contingency events such as inadvertent breaker operation and bus faults may be considered if the probability of such an event is relevant. The method for determining those Contingencies must also be identified in the RC's methodology as per Requirement R5 Part 5.2.

Requirement R5 Parts 5. 1 through 5.4 require that differences in Contingency events for determining stability limits, those used for OPAs and those used for RTAs, be specified in the RC's methodology. It is important to distinguish between Contingencies used for determining stability limits and those that are actually applied in OPAs and RTAs as only specific system conditions may actually warrant their use in the days leading up to real-time operations. For example, multiple Contingencies at heightened risk under specific weather or system conditions may not need to be respected (and thus monitored) the majority of the time when these conditions are not present.

Requirement R5 Part 5.4 compliments the proposed Requirement R6 in FAC-015-1 by ensuring the RC's methodology describes how the Contingency event information from the Planning Coordinator is used in deriving stability limits used in operations.

Requirement R6

Each Reliability Coordinator shall include in its SOL Methodology:

6.1 A description of how to identify the subset of SOLs that qualify as IROLs.
6.2 Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V.

Rationale R6

The two IROL related requirements in FAC-011-3 were preserved under Requirement R6.

Requirement R7

Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s).

Rationale R7

Requirement R7 serves as a companion to FAC-014-3 Requirement R3 which states, *"The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology."*

The language in Requirement R7 is written to provide clarity that the TOP is responsible for communicating only those SOLs that it established for its own Transmission Operator Area. The TOP is not responsible for communicating SOLs established by other TOPs that it uses in its analyses.

While it is possible to address communication of SOLs through TOP-003-3 and IRO-010-2, the standard drafting team determined that the communication of SOLs was of such importance to the reliability of the BES that it should be addressed specifically in the RC's SOL Methodology and in FAC-014-3. Additionally, the aforementioned Reliability Standards address the data specifically necessary for performing OPA, Real-time monitoring, and RTA. SOL information may be necessary for other uses beyond these analyses, for example in outage coordination assessments.

Requirement R8

Each Reliability Coordinator shall provide its new or revised SOL Methodology to:

8.1 Each adjacent Reliability Coordinator within its Interconnection prior to the effective date of the SOL Methodology;
8.2 Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;
8.3 Each Transmission Operator within its Reliability Coordinator Area prior to the effective date of the SOL Methodology;

8.4 Each requesting Reliability Coordinator that indicates a reliability-related need and is not considered adjacent in Part 8.1, within 30 calendar days of receiving the request.

Rationale R8

Requirement R8 preserves the reliability objective of providing the SOL Methodology to the appropriate entities from Requirement R4 of FAC-011-3. Requirement R8 Part 8.1 mandates that an RC provide its SOL Methodology to each adjacent RC within its Interconnection. In Requirement R8 Part 8.2, PC, not Planning Authority, was used to be consistent with the Functional Model as well as to be consistent with TPL-001. Requirement R8 Part 8.2 also uses “responsible for planning” instead of “models any portion of” to identify those PCs and TPs who have a reliability-related need rather than a PC/TP who simply has acquired a model that contains a portion of the Reliability Coordinator Area, but does not plan for that area. Requirement R8 Part 8.4 differs from Requirement R8 Parts 8.1 through 8.3 in that it mandates that an RC provide its SOL Methodology to any requesting RC that indicates a reliability-related need within 30 calendar days of such request rather than prior to the effective date of the SOL Methodology.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

FAC-011-4 System Operating Limits Methodology for the Operations Horizon

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-011-4 System Operating Limits (SOL) Methodology for the Operations Horizon. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

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

FERC Guidelines for Violation Risk Factors

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

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

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

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

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

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

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-011-4 Requirement R1	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-013-2, Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for establishing SOLs has the potential unintended consequence of creating inconsistencies in establishing SOLs which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	The requirement contains one objective, therefore a single VRF is assigned.

mingle More than One Obligation	

VSLs for FAC-011-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.

VSL Justifications for FAC-011-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R2	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of improper Facility Ratings could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.

VSL Justifications for FAC-011-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 sub-requirement R1.2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect System Voltage Limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R4	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard TPL-001-4, Requirement R3, Part 3.4, which requires development of a list of contingencies to be evaluated for System performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Incorrectly identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs) could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of Requirement R5 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3, sub-requirements R3.2, R3.3, and R3.3.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirements R1, R3, and R4 which requires development of Interconnection Reliability Operating Limits (IROLs) to be consistent with a methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator failed to include Part 6.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (a criteria for determining when violating a SOL qualifies as an IROL) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	The Reliability Coordinator failed to include Parts 6.1 and 6.2 in its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1, sub-requirement R1.3 and Requirement R3, sub-requirement R3.7. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R7	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements (Parts) so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved other standards in the BAL, COM, EOP, IRO, and TOP families that require notification to other entities for situational awareness of the BES.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to communicate identified SOLs could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.

VSL Justifications for FAC-011-4, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R8	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of lower for this requirement is consistent with approved Reliability Standard FAC-010-3, Requirement R4, FAC-011-3, Requirement R4, and FAC-013-2, Requirement R2 which requires notification of a new or revised methodology to other entities.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to provide its SOL methodology to entities within and adjacent to its Reliability Coordinator Area could affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4 but was late by less than or equal to 10 calendar days.	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Parts 8.1 through 8.3. OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two or more of the parties specified in Parts 8.1 through 8.3. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology. OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability

			Coordinator in accordance with Part 8.4.

VSL Justifications for FAC-011-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs map to the currently-effective FAC-011-3 Requirement R4. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16

Anticipated Actions	Date
45-day formal comment period with ballot	September 2017 – October 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-2~~2~~3

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

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Reliability Coordinator

~~**1.1.** Planning Authority~~

~~**1.2.** Transmission Planner~~

4.1.2. Transmission Operator

~~**2. Effective Date:** April 29, 2009~~

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

B. Requirements and Measures

~~The~~

R1. Each Reliability Coordinator shall ~~ensure that SOLs, including~~ establish Interconnection Reliability Operating Limits (IROLs~~),~~) for its Reliability Coordinator Area ~~are~~in accordance with its System Operating Limit Methodology (SOL Methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established ~~and that the SOLs (including Interconnection Reliability Operating Limits) are consistent~~IROLs in accordance with ~~its~~it SOL Methodology.

R2. ~~The~~Each Transmission Operator shall establish ~~SOLs (as directed by its Reliability Coordinator~~System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area ~~that are consistent~~in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL Methodology.

~~**R1.**~~**R3.** The ~~Planning Authority~~Transmission Operator shall ~~establish SOLs, including IROLs, for~~provide its ~~Planning Authority Area that are consistent~~SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. ~~The Transmission Planner shall establish SOLs, including IROLs, for its~~Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission ~~Planning Area that are consistent~~Operator provided its SOLs in accordance with its ~~Planning Authority's~~Reliability Coordinator's SOL Methodology.

~~**R1.** The Reliability Coordinator, Planning Authority, and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:~~

R4. ~~The~~Each Reliability Coordinator shall ~~provide its SOLs~~establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) ~~to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and~~ at least once every twelve calendar months.

~~**1.1.**~~**5.2.** Each impacted Planning ~~Authorities~~Coordinator within its Reliability Coordinator Area~~. For~~, the following information for each established stability limit and each established IROL~~, the Reliability Coordinator shall provide the following supporting information~~ at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

~~**1.1.1.**~~**5.2.2.** Identification ~~and status~~ of the ~~associated Facility (or group of~~ Facilities~~)~~ that ~~is (~~are~~)~~ critical to the derivation of the stability limit or IROL~~.~~;

~~**1.1.2.**~~**5.2.3.** The ~~value of the IROL and its~~ associated IROL T_V~~.~~ for any IROL;

~~**1.1.3.**~~**5.2.4.** The associated Contingency(ies~~).~~); and

~~**1.1.4.**~~**5.2.5.** The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3. ~~The~~Each impacted Transmission Operator ~~shall provide any SOLs it developed~~within its Reliability Coordinator Area, the value of the stability limits established pursuant to ~~its Reliability Coordinator~~Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame

necessary for inclusion in the Transmission ~~Service Providers that share its portion of the~~ Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

~~1.2.~~5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

~~**R1.1.** The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.~~

~~**R1.2.** The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.~~

~~**R2.** The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.~~

~~**R2.1.** The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.~~

~~**R2.2.** If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the~~ Each requesting Transmission Operator within its Reliability Coordinator~~.~~

~~A. Measures~~

5.5. ~~The~~ Area, requested SOL information for its Reliability Coordinator~~, Planning Authority, Transmission Operator, and Transmission Planner shall each be able~~ Area, on a mutually agreed upon schedule.

~~**M4.**~~ Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that ~~it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.~~

~~**M5.** The~~ the Reliability Coordinator~~, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.~~

~~**M6.**~~**M5.** ~~The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and~~ provided the ~~list and the limits to its Reliability Coordinators~~information in accordance with Requirement ~~6~~R5.

R6. Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator provided the list of Facilities in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

~~**2.1. Compliance Monitoring Responsibility**~~

~~Regional Reliability Organization~~

~~**2.2. Compliance Monitoring Period and Reset Time Frame**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.~~

~~The Performance-Reset Period shall be twelve months from the last finding of non-compliance.~~

~~**2.3. Data Retention**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.~~

~~The Compliance Monitor shall keep the last audit and all subsequent compliance records.~~

~~**2.4. Additional Compliance Information**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:~~

~~**2.4.1** SOL Methodology(ies)~~

~~**2.4.2** SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information~~

~~**2.4.3** Evidence that SOLs were distributed~~

~~**2.4.4** Evidence that a list of stability-related multiple contingencies and their associated limits were distributed~~

~~**2.4.5** Distribution schedules provided by entities that requested SOLs~~

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through R6 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels~~:~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	~~There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs~~The Reliability Coordinator did not establish Interconnection Reliability Operating Limits (IROLs) for ~~the~~its Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the Reliability Coordinator's~~ its System Operating Limit Methodology ("SOL Methodology~~. (R1)~~") as established in FAC-011-4.
R2.	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	The Transmission Operator ~~has established~~did not establish SOLs for its portion of the Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the~~its Reliability Coordinator's SOL Methodology~~. (R2)~~
R3.	~~There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than,~~	~~There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50%~~	~~There are~~The Transmission Operator provided its SOLs	~~There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are~~

	~~25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~N/A	~~of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~N/A	~~for the Planning~~to its Reliability Coordinator ~~Area~~, but ~~50% or more, but less than 75% of these~~did not provide its SOLs ~~are inconsistent with~~at the periodicity at which the ~~Planning Coordinator's SOL Methodology. (R3)~~RC needs such information to perform its reliability functions.	~~inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~The Transmission Operator did not provide its SOLs to its Reliability Coordinator.
R4.	~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	~~The Transmission Planner has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	The Reliability Coordinator did not determine stability limits to be used in operations when the limit impacts more than one Transmission ~~Planner has established SOLs for~~Operator in its ~~portion of the Planning~~Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the Planning Coordinator's~~its SOL Methodology. ~~(R4)~~
R5 ~~.~~	~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)~~	~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting~~	~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting~~	~~One of the following:~~ ~~The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45~~

	The Reliability Coordinator did not provide one of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.4~~ The Reliability Coordinator did not provide two of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.3~~ The Reliability Coordinator did not provide three of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~calendar days of the associated schedules. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.~~ The Reliability Coordinator did not provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.5.
R6 ~~:~~	~~The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2~~N/A	~~Not applicable.~~N/A	~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~ N/A	~~The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6)~~ ~~OR~~ ~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~The Reliability Coordinator with an established IROL, or the

				Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

D. Regional ~~Differences~~Variances

None ~~identified.~~

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revision

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Mapping Document for FAC-014-2

Project 2015-09 Establish and Communicate System Operating Limits

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-014-2, Requirement R1 R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.	Requirements R1, R2, and R4 of FAC-014-3 R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology. R4. Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL Methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL Methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL Methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		not ensure that the TOP's SOL was consistent with its SOL Methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
FAC-014-2, Requirement R2 R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	FAC-014-3, Requirement R2 R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly understood to mean that the TOPs are

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.		only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL Methodology.
FAC-014-2, Requirements R3 and R4 R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.	1. FAC-011-4, Requirement R8, Part 8.2 2. FAC-015-1, Requirements R 1 – R6 FAC-011-4, Requirement R8, Part 8.2: R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.2. Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The PCs and TOPs responsible for planning any portion of the RC's Area are made aware of the RC's SOL Methodology through FAC-011-4, Requirement R8, Part 8.2. By having the RC's SOL Methodology, PCs and TPs who plan any portion of the System in the RC Area have knowledge of the methods and criteria for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. New Reliability Standard FAC-015-1 along with the changes made to FAC-011-4 and FAC-014-3 represent an improvement for

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	FAC-015-1: R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its	planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-015-1, Requirements R1 – R3 ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R1 addresses Facility Ratings used in Planning Assessments, Requirement R2 addresses the System steady state voltage limits used in Planning Assessments, and Requirement R3 addresses the stability performance criteria used in Planning Assessments. These requirements address the three components of SOLs used in operations and facilitates continuity between operations and planning.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators. R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more	Implementing the processes required in FAC-015-1, Requirements R1 – R3 provides the PC with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R4 requires the PC to provide those Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its TPs and to requesting PCs. FAC-015-1, Requirement R5 requires the TP to use the Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its PC. By implementing Requirements R1 – R5 of FAC-015-1, equally limiting or more limiting Facility Ratings, System steady-

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator. R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-	state voltage limits and stability criteria that are established in accordance with the RC's SOL Methodology are ultimately implemented in the Planning Assessments performed by the PCs and TPs, thus improving reliability by ensuring continuity between planning and operations. FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation identified in the Planning Assessments to the RC and to impacted TOPs. The subparts of Requirement R6 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	
<u>FAC-014-2, Requirement R5, R5.1</u> R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities) 2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) <u>FAC-014-3, Requirement R5:</u> R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area, the following	Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1. While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3, Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs,

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies); and 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the	which addresses RC-to-RC communication and coordinated operations issues.

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	information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. <u>IRO-014-3, Requirement R1</u> R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: 1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages.	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
FAC-014-2, Requirement R5, R5.2 R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2.6 FAC-014-3, Requirement R3 R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. MOD-028-2, Requirement R7: R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than:	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3. The revised language represents an improvement on the current standard because the specifics of TOP communication to the RC is now addressed in the RC's SOL Methodology. This revised requirement has a companion Requirement R7 in FAC-011-4 which states: R7. Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s).

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. MOD-029-2a, Requirement R4: R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. MOD-030-3, Requirement R2.6: [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	The Transmission Service Provider (TSP) was removed from the SOL communication chain because the TSP does not need SOLs to perform its obligations specified in the Modeling, Data, and Analysis (MOD) standards; rather, they need Total Transfer Capability (TTC) and Total Flowgate Capability (TFC) from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs.
FAC-014-2, Requirement R5, R5.3 and R5.4 R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators	1. FAC-015-1, Requirements R1 – R6 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2 5. TPL-001-4, Requirement R8 FAC-015-1, Requirements R1 –R6:	Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1. Implementing the processes required in FAC-015-1, Requirements R1 – R3

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the	provides the PC with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R4 addresses the PC's role for providing the Facility Ratings, System steady-state voltage limits and stability performance criteria derived from Requirements R1 – R3 to the TPs and to requesting PCs for their use in performing Planning Assessments. FAC-015-1, Requirement R5 requires the TP to use the Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its PC. FAC-015-1, Requirements R1 – R5 result in PC and TPs using Facility Ratings, System steady state voltage limits, and stability performance criteria in their

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators. R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-	Planning Assessments that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation identified in the Planning Assessments to the RC and to impacted TOPs. The subparts of Requirement R6 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. The TSP was removed from the SOL communication chain. The TSP does not need SOLs from the PCs or TPs; rather, TSPs need TTC and TFC from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	state voltage limits, and stability criteria provided by its Planning Coordinator. R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;	TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs. TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. With this requirement, any functional entity with a reliability-related need for a PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation. MOD-028-2, Requirement R7: R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. MOD-029-2a, Requirement R4: R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path.	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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	MOD-030-3, Requirement R2.6: [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment. TPL-001-4, Requirement R8: R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. 8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
FAC-014-2, Requirement R6 R6. The Planning Authority shall identify the subset of multiple contingencies (if any),	FAC-015-1, Requirement R6 R6. Each Planning Coordinator shall communicate any instability, Cascading or	FAC-015-1, Requirement R6 cover the content of FAC-014-2, Requirement R6 and improves upon it as follows:

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of the instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	• FAC-015-1, Requirement R6 addresses not only the identification of multiple contingencies that result in stability limits, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6, FAC-015-1, Requirement R6 ensures the type of instability, relevant stability criteria, and mitigation assumptions used by the PC are communicated to the appropriate RC. • Additionally, FAC-015-1, Requirement R6 includes all planning events (single and multiple contingencies) that result in instability, Cascading, or uncontrolled separation. • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-015-1, Requirement R6 because all instances of instability identified by the PC are to be communicated

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		to the RC in accordance with FAC-015-1, Requirement R6. In addition, FAC-014-2, Requirement R6, R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-015-1, Requirement R6 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rationales for FAC-014-3

September 2017

Requirement R1

Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL Methodology).

Rationale R1

Reliability Standard FAC-014-2 Requirement R1 requires that the Reliability Coordinator (RC) ensure that System Operating Limits (SOLs), including Interconnection Reliability Operating Limits (IROLs), for its RC Area are established and that the SOLs (including IROLs) are consistent with its SOL Methodology.

Furthermore, Requirement R2 of FAC-014-2 requires the Transmission Operator (TOP) to establish SOLs consistent with its RC's SOL Methodology.

Under this structure the RC is responsible for ensuring that SOLs established by the TOP, per Requirement R2, are consistent with the RC's SOL Methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP.

Accordingly, if the TOP does not establish SOLs per its RC's SOL Methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did not ensure that the TOP's SOL was consistent with its SOL Methodology.

The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.

Requirement R2

Each Transmission Operator shall establish System Operating Limits (SOL) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R2

Requirement R2 preserves the intent of Requirement R2 of FAC-014-2.

The standard drafting team (SDT) removed language from the existing FAC-014-2 Requirement R2 that states the TOP "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the SDT has removed the unnecessary and potentially confusing language. The

proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL Methodology.

Requirement R3

The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R3

Requirement R3 requires TOPs to provide the SOLs it established (under requirement R2) to the RC in accordance with the RC's SOL Methodology. This requirement is a companion requirement to FAC-011-4 Requirement R7, which states: "Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its RC(s). The method shall address the periodicity of SOL communication." These two requirements work together to ensure that SOLs established by the TOP in accordance with the RC's SOL Methodology are communicated to the RC in a timely manner.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2, but the proposed requirement may also be utilized for SOL information other than what is utilized for Operational Planning Analysis (OPA)/ Real-time Assessment (RTA)/ Real-time monitoring. In such instances, the timing requirements should be coordinated between the RC's SOL methodology and the data specification document.

Requirement R4

Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

Rationale R4

Requirement R4 requires that the RC establish stability limits to be used in operations when the limit impacts more than one TOP in its RC Area. This ensures that the RC who has wide-area responsibility will identify such stability limits and prevent any gaps in identification and monitoring of stability limits that impacts more than one TOP in its RC Area. TOPs are still required to identify stability limits that are within its TOP area (including Generator Operator areas interconnected to its TOP area).

Requirement R5

Each Reliability Coordinator shall provide:

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area,, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL;

5.2.3. The associated IROL T_v for any IROL;

5.2.4. The associated Contingency(ies); and,

5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analysis, Real-time monitoring, and Real-time Assessments.

5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

Rationale R5

Requirement R5 requires the RC to provide SOLs (including the subset that are IROLs) and any updates to those SOLs to Planning Coordinators (PCs) and Transmission Operators (TOP)s. This is an improvement over Requirement R5 in FAC-014-2 because it provides additional clarity on when the RC is responsible for performing these tasks. FAC-014-2 Requirement R5 includes the triggering clause of when entities "provide a written request that includes a schedule for delivery of those limits", while Requirement R5 of FAC-014-3 clearly identifies the RC's responsibilities with or without a request. This also removes confusion associated with FAC-010 in terms of SOLs existing in the planning horizon. All requirements in pertaining to SOLs in the planning horizon have thus been removed.

The requirement addresses varying needs in terms of both the content and the frequency at which the information is provided. This requirement also complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information (e.g. TOP-003-3, IRO-010-2, IRO-014-3) to prevent redundancies in requirements. TOP-to-TOP SOL information communication is addressed in TOP-003-3. RC-to-RC SOL information communication is addressed

in IRO-014-3. TOP-to-RC information communication is addressed in Requirement R3 and may be addressed in IRO-010-2.

Requirement R5 Part 5.1 requires the RC to provide the PCs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PC the relevant information necessary for its assessments and its Transmission Planner's (TP's) assessments. MOD-032-1 and FAC-015-1 requirements provides the mechanism for SOLs to be communicated between the PCs and its TPs. It is expected that PCs do not need more frequent updates as most of their assessments are performed on an annual cycle. Transmission Service Providers were not retained as an entity that would have a reliability related need for stability limit and IROL related information. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle.

Requirement R5 Part 5.3 requires the RC to provide the impacted TOPs within its RC Area the value of the stability limits established in Requirement R4 and IROLs established in Requirement R1 in the Real-time Operations time horizon. This recognizes that the actual numerical "limit" (whether a new limit or modification of an existing one) may change based on varying system topology and thus those limit values must be provided in a timeframe designed to meet the impacted TOP's needs for their OPA, Real-time monitoring, and RTA.

Requirement R5 Part 5.4 requires the RC to provide the impacted TOPs additional specific information (consistent with FAC-014-2 R5.1.1-5.1.4) for stability limits and IROLs within Same-day or Operations Planning time horizon. This additional information is essential for the TOP's OPA; however, it can be communicated within a longer-term agreed upon time frame outside the Real-time Operations time horizon.

Additionally, Requirement R5 Part 5.5 requires that if a TOP requests any SOL information beyond what impacts that TOP, the RC must provide this SOL information as well. Both Requirement R5 Parts 5.4 and 5.5 require that the related information be provided in a mutually agreed upon schedule to ensure the TOP's needs are met (e.g. OPA, RTA, etc.) and the RC's ability to meet those needs are taken into consideration.

Requirement R6

Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

Rationale R6

Requirement R6 addresses FERC Order No. 777 directive for the communication of IROL information to Transmission Owners (TOs) (P6 and P41). FERC Order No. 777 states:

> *"As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners." (P 6) "NERC should establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners...One way to achieve this objective...is to modify FAC-014 to require the provision of IROLs to transmission owners. However, we leave it to NERC to determine the most appropriate means for communicating IROL status to transmission owners." (P 41)*

Requirement R5 Parts 5.2.1 through 5.2.5 requires that IROL information – including the Facilities critical to the derivation of the IROL – be communicated to the TOPs. SDT determined that while TOs and Generator Owners (GOs) need to be made aware of their Facilities that are critical to the derivation of the IROL, the TOs and GOs do not need to know the other IROL information specified in Requirement R5 Part 5.2.1 and Parts 5.2.3 through 5.2.5. These items may contain operationally sensitive information that should be limited to the TOPs that operate the equipment. Therefore, the SDT separated the communication to the TOs and GOs into a stand-alone Requirement R6.

The language "Each Reliability Coordinator that is impacted by an IROL" was used to cover scenarios where an IROL in one Reliability Coordinator Area contains Facilities that reside in a neighboring Reliability Coordinator's Area that are critical to the derivation of the IROL. Therefore, any Facilities that are critical to the derivation of an IROL will be communicated from the responsible RC to the appropriate TOs and GOs.

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Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Guidelines for Violation Risk Factors

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

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

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

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

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

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

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-014-3 Requirement R1	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (“SOL Methodology”) as established in FAC-011-4.

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but did not provide its SOLs at the periodicity at which the RC needs such information to perform its reliability functions.	The Transmission Operator did not provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.5.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	**High**

This reliability objective of Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R6 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator with an established IROL, or the Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with ballot	September 2017 – November 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board adoption	May 2018

A. Introduction

1. **Title:** Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

2. **Number:** FAC-015-1

3. **Purpose:** To ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the Reliability Coordinator's System Operating Limits (SOL) Methodology.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Transmission Planner

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

B. Requirements and Measures

R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R1.

R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R2.

R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R3.

R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinator's. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator provided its information in accordance with Requirement R4.

R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Transmission Planner used the information provided by its Planning Coordinator in accordance with Requirement R5.

R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- **6.1** The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);
- **6.2** The associated stability criteria used as part of determining the instability;
- **6.3** The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;
- **6.4** Any Remedial Action Scheme action, undervoltage load shedding (UVLS) action, underfrequency load shedding (UFLS) action, interruption of Firm Transmission

Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and

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

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

C. Compliance

1. Compliance Monitoring Process

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

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator and Transmission Planner shall keep evidence for Requirements R1 through R6 for the most current year plus the previous three years.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.
R2.	N/A	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.
R3.	N/A	The Planning Coordinator used less limiting stability	The Planning Coordinator used less limiting stability	The Planning Coordinator failed to implement a

		performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	process to ensure that stability performance criteria used in planning assessments are equally limiting or more limiting than those used in operations established in the Reliability Coordinator's SOL Methodology.
R4.	N/A	N/A	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide one element of the required information.	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide two or more elements of the required information.
R5.	N/A	N/A	N/A	The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were equally or more limiting than those provided by its Planning Coordinator.

R6.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R6, Parts 6.1 – 6.5. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1		Project 2015-09 SOL – Adopt new standard.	New

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rationale for FAC-015-1

September 2017

Requirement R1

Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R1

Requirement R1 was drafted to ensure the appropriate use of applicable Facility Ratings in planning models. Analysis of these models determines System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Requirement R1 provides a mechanism for the coordination of Facility Ratings in planning models to those established in accordance with the Reliability Coordinator's (RC's) System Operating Limit (SOL) Methodology. Since the analysis of planning models determines what facilities are constructed or modified, Facility Ratings used in these analyses should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by thermal constraints that were not identified in preceding planning studies.

Reliability Standard MOD-032 requires the modeling data in a Planning Coordinator (PC) area be coordinated between the PC and applicable Transmission Planners (TPs). It is the opinion of the standard drafting team (SDT) that the resulting coordination is the appropriate means to ensure Facility Ratings included in planning models are equally limiting or more limiting than the Facility Ratings established in accordance with the RC's SOL Methodology, since Planning Assessments and Corrective Action Plans are developed based on analysis of these models (TPL-001).

The Near-Term Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System. This is accomplished by requiring the PC to use Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. If less limiting Facility Ratings are used by the PC, a technical justification is required to be documented and provided to the RC. This does

not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R2

Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R2

The purpose of TPL-001 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001, planning criteria used in developing the Planning Assessment should support the eventual operation of BES Facilities.

Requirement R2 was drafted to ensure the use of appropriate System steady-state voltage limits when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what Facilities are constructed or modified, the application of System steady-state voltage limits used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by voltage constraints that were not identified in preceding planning studies. Requirement R2 provides a mechanism for the coordination of System steady-state voltage limits evaluated in planning studies with the System Voltage Limits established in accordance with the RC's SOL Methodology.

The Near-Term Transmission Planning Horizon is specified because planning assumptions tend to be more certain earlier in the planning horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.
The intent of Requirement R2 is to supplement Requirement R5 of TPL-001-4 which states, "Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level

and a maximum length of time that transient voltages may remain below that level." When determining the criteria for System steady-state voltage limits in accordance with TPL-001-4 Requirement R2, the PC is required to implement the process described in FAC-015-1 Requirement R2.

Requirement R2 requires the PC to use System steady-state voltage limits that are equally limiting or more limiting than the System Voltage Limits established in accordance with the RC's SOL methodology. If less limiting System steady-state voltage limits are used by the PC, a technical justification is required to be documented and provided to the RC. This does not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R3

Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R3

The purpose of TPL-001-4 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probably Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001-4, planning criteria used in developing the Planning Assessment should support the eventual operation of BES facilities.

Requirement R3 was drafted to ensure the use of appropriate stability performance criteria when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what facilities are constructed or modified, the application of stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than the criteria specified in the RCs SOL Methodology. Otherwise, operators could be unduly limited by stability constraints that were not identified in preceding planning studies. Requirement R3 provides a mechanism for the coordination of stability performance criteria evaluated in planning studies with the Reliability Coordinator's SOL Methodology.

The Near-Term Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R3 is to address the stability performance criteria used by PCs and TPs when performing the required stability analysis per TPL-001. When the PC performs the relevant stability analyses in accordance with TPL-001, they are required to implement the process in FAC-015-1 Requirement R3, which requires the PC to use stability performance criteria that are equally limiting or more limiting than the criteria established in accordance with the RC's SOL Methodology. If less limiting stability performance criteria are used by the PC, a technical justification is required to be documented and provided to the RC. This does not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R4

Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators.

Requirement R5

Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator.

Rationale R4 and R5

Requirements R4 and R5 provide for the explicit coordination between PCs and TPs of Facility Ratings, System steady-state voltage limits, and stability performance criteria used to develop Planning Assessments of the PC area. Additionally, Requirement R4 provides a mechanism for other PCs to obtain this same information, as needed. Requirement R5 also allows the TP to use more conservative Facility Ratings, System steady-state voltage limits, and stability performance criteria than those the PC provides where the TP deems appropriate

These requirements supplement TPL-001-4 Requirements R1, R5, and R6 by ensuring Facility Ratings, System steady-state voltage limits, and stability performance criteria are consistently applied in Planning Assessments of the PC area.

Requirement R6

Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its

Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include:

- **6.1** The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);
- **6.2** The associated stability criteria used as part of determining the instability;
- **6.3** The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;
- **6.4** Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;
- **6.5** Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

Rationale R6

IRO-017-1 Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2 Part 2.4 and Requirement R4 in TPL-001-4, which outline the Stability analysis portion of the Planning Assessment, do not provide for the level of detail prescribed in FAC-015-1 Requirement R6. Therefore this requirement was drafted to ensure the appropriate details regarding potential instability identified in the Stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted RC and Transmission Operators (TOPs).

The information itemized in Requirement R6 is a key consideration for RC and TOPs in the establishment of SOLs. Of particular importance is the identification of potential risks of instability, Cascading conditions and uncontrolled separation that warrant establishment of an IROL by the RC. The details required by Requirement R6 will supplement the severe System conditions identified Requirements R4 Parts 4.4 & 4.5 of TPL-001-4.

Violation Risk Factor and Violation Severity Level Justifications

FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator's System Operating Limits (SOL) Methodology. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

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

FERC Guidelines for Violation Risk Factors

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

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

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

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

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

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

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-015-1 Requirement R1	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R1 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that stability performance criteria used in planning assessments are equally limiting or more limiting than those used in operations established in its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R4	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 from approved Reliability Standard FAC-014-2 is now Requirement R4 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide one element of the required information.	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide two or more elements of the required information.

VSL Justifications for FAC-015-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R5	
Proposed VRF	**Medium**

This reliability objective of Requirement R4 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were equally or more limiting than those provided by its Planning Coordinator.

VSL Justifications for FAC-015-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R6	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R6 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain one of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain two of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain three elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain four or more of the elements listed in Requirement R6, Parts 6.1 – 6.5. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-015-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.3 and R6 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

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Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s)

- 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

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
- Transmission Planner
- Transmission Operator

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, and FAC-015-1 and the NERC Glossary term "System Voltage 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 and the NERC Glossary term "System Voltage 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, 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 the NERC Glossary term "System Voltage 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 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 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, and FAC-015-1.

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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Rationales for FAC-010-3 (Retirement) and FAC-015-1

September 2017

Background

The Facilities Design, Connections, and Maintenance (FAC) group of Reliability Standards provide for, among other things, the important reliability objective of establishing and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) that help ensure reliable operation of the Bulk Electric System (BES). Specifically, under currently-effective Reliability Standard FAC-010-3, each Planning Authority must have a documented methodology for establishing SOLs (including IROLs) used in the planning horizon. Currently-effective Reliability Standard FAC-011-3 requires each Reliability Coordinator (RC) to have a documented methodology for establishing SOLs (including IROLs) within its Reliability Coordinator Area for the operations horizon. Further, under currently-effective Reliability Standard FAC-014-2, Transmission Operators (TOPs) must establish and communicate SOLs consistent with the RC's methodology and RCs must determine and communicate which of those SOLs are deemed as IROLs. Likewise, FAC-014-2 requires Planning Coordinators (PCs) and Transmission Planners (TPs) to establish and communicate SOLs and IROLs used in the planning horizon consistent with the PC's SOL Methodology.

The FAC-010, FAC-011, and FAC-014 Reliability Standards, however, have remained essentially unchanged since they were initially developed and became effective in 2008. Since that time there have been many improvements to other mandatory NERC Reliability Standards that work in concert with those FAC Reliability Standards, namely, those in the Transmission Planning (TPL), Transmission Operations (TOP), and Interconnection Reliability Operations and Coordination (IRO) groups of Reliability Standards. Specifically, the retired versions TPL-001, 002, 003, and 004 Reliability standards have been replaced with currently-effective TPL-001-4, all of the TOP standards have been replaced with the currently-effective TOP-001-3, TOP-002-4, and TOP-003-3, and all of the IRO standards have been modified. The FAC Reliability Standards that address SOLs and IROLs are inextricably linked to many of these TPL, TOP, and IRO Reliability Standards, as they all address in some manner the foundational reliability concept of reliable system performance as it relates to SOLs and IROLs. While the changes to the TPL, TOP, and IRO standards have been significant and have evolved as industry practices and needs have changed, there have been no consequential substantive changes to the related FAC Reliability Standards. One of the primary objectives of Project 2015-09 is to make changes to the SOL/IROL-related FAC standards to create better alignment with the currently-effective TPL, TOP, and IRO Reliability Standards.

The Project 2015-09 standard drafting team (SDT) is proposing to make a significant improvement to the SOL/IROL-related FAC standards by minimizing redundancy, allowing for better continuity from the establishment to communication of SOLs, and improving the efficiency and effectiveness of the tasks performed by planners and operators to achieve the ultimate reliability objective of reliable system performance in operations. As discussed in this whitepaper, one of the fundamental changes proposed by

the SDT is to retire the FAC-010-3 Reliability Standard, eliminating the requirement for PCs to have a methodology for establishing SOLs for use in the planning horizon, as well as the corresponding requirements in the FAC-014 Reliability Standard related to the establishment and communication of planning horizon SOLs and IROLs. As discussed further below, the SDT concluded that, with the changes in TPL-001-4, the establishment of planning horizon SOLs were unnecessary and not useful for ensuring reliable planning or reliable operations. Rather, the SDT concluded, the reliability need was for the limits and criteria used in the TPL-001-4 Planning Assessments to be equally limiting or more limiting than those established in accordance with or identified within its RC's SOL Methodology. The SDT developed proposed FAC-015-1 to ensure the coordination of the limits and criteria used in the Planning Assessment with the RC's SOL Methodology.

Under the current construct, PCs and RCs may have significantly different SOL Methodologies as the currently-effective Reliability Standards (FAC-010-3, FAC-011-3 & FAC-014-2) do not have any link requiring coordination between the methodologies. Furthermore, the nature of the current construct does not address continuity between planning and operations and may potentially result in a system not adequately planned for operational needs. The SDT's proposed changes help address the potential for inconsistencies between the PC's SOL Methodology and the RC's SOL Methodology.

Additionally, because of the evolution of the TPL standards, there are many redundancies in the responsibilities for PCs and Transmission Planners (TPs) between those in FAC-010/FAC-014 and those in TPL-001-4. In fact, planners are under no obligation to use (and many do not use) the PC's SOL Methodology for their Planning Assessments. Under Reliability Standard TPL-001-4, the SOLs established for the planning horizon pursuant to the FAC-010 and FAC-014 Reliability Standards are not necessary for reliable planning.

The SDT's proposal addresses both of these issues by providing for better continuity between planning and operations and by eliminating any redundancies that exist. To accomplish these objectives, the SDT is proposing a new construct. Under the proposed construct, the terms "SOL" and "IROL" are only applicable to the operations horizon and, in turn, only the RC would have an obligation to develop an SOL Methodology. RCs and TOPs would continue to have the responsibility under the FAC-014 Reliability Standard for establishing SOLs and IROLs consistent with the RCs' SOL Methodology. Planners, however, would no longer have an obligation to have an SOL Methodology applicable for the planning horizon, nor would planners be required to establish SOLs and IROLs for use in the planning horizon. Instead, planners would continue to perform Planning Assessments in accordance with TPL-001-4, and work with operating entities per the proposed new standard FAC-015-1 to ensure continuity between planning and operations. Specifically, under proposed FAC-015-1, planners are responsible for ensuring that the Facility Ratings, System (steady-state) voltage limits, and stability performance criteria used in their planning assessments for the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria as determined in accordance with the RC's SOL Methodology.

This whitepaper demonstrates that the proposed construct would improve reliability by eliminating redundancies and by providing better continuity between planning and operations. The primary principles of the proposed approach include:

- Clarifying that SOLs are established only for the *operations horizon,* which aligns with the *"Operating"* term in System *"Operating"* Limits. Additionally, IROLs are better identified by the RC in the operations time horizon.

- The existing FAC-010-3 and related requirements in FAC-014-2 are addressed by TPL-001-4 and proposed FAC-015-1such that the retirement of FAC-010 and related requirements in FAC-014-2 would not create any reliability gaps.

- The addition of FAC-015-1 consolidates PC and TP requirements related to coordination of limits and criteria utilized in the planning horizon with those used in the operations horizon into one standard. This reduces the risk of multiple varying methodologies/processes, clarifies the usage of such limits and criteria (TPL-001-4, FAC-010-3, FAC-013-2) and eliminates any redundancy with such limits and criteria.

- Clarity and efficiency of communication of limits and criteria between planning and operating entities is improved with FAC-015-1.

System Operating Limits in the Planning Horizon

There are two different time frames in which the system is analyzed to ensure reliable operation: the planning horizon and the operations horizon. The time frame covered by the PC's SOL methodology developed pursuant to FAC-010-3 is for the *planning horizon*. The planning horizon covers the period from one year and beyond, while the operations horizon covers real-time (now) to one year. Between those two time horizons, the topology of the system could be quite different based on the addition of new projects, changes in generation, planned or forced outages of elements, and different uses of the system (power transfers), and weather.

Under the currently-effective FAC Reliability Standards, planners must establish SOLs for use in the planning horizon and operators must establish SOLs for use in operations. The initial intent for requiring planners to establish SOLs for use in the planning horizon was to develop a consistent set of limits to be used by the TPs while *planning* for the reliability of the transmission system. To ensure this consistency, the PC develops the SOL Methodology to be used by its TPs and thus provide for an overall, coherent transmission plan for a PC area.

The purpose of requiring the establishment of SOLs for the operations horizon is to identify limits that if operated within, will result in the system being *operated* reliably. TOPs must establish SOLs in the operations horizon that account for real-time characteristics (generation, load, topology and transfers) of their system. To ensure the consistent use of limits within a RC area, the RC is obligated to develop the SOL methodology to be used by its TOPs. The RC's methodology includes how Facility Ratings, System Voltage Limits, and stability performance criteria will be used to establish limits for use in assessments that determine whether the system is being reliably *operated*. Additionally, the RC's methodology prescribes what tests (Contingencies) must be used during the reliability assessment of the system during operations.

One of the key aspects of the proposed new construct is to eliminate the use of the SOL term as applied to the planning horizon. The SDT views SOLs as limits that are used in operations, hence the use of the term

"Operating" in System "Operating" Limits. The components of SOLs include the use of Facility Ratings, System Voltage Limits, and stability limits. These SOLs are based on specifications and criteria identified in the RC's SOL Methodology. While planners also use Facility Ratings provided by Facility Owners, System steady state voltage limits (TPL-001-4 Requirement R5), and stability performance criteria (TPL-001-4 Requirement R6) for its Planning Assessments, these are not referred to as SOLs.

The SDT determined that there is limited value in requiring PCs and TPs to establish SOLs for use in the planning horizon. Rather, the SDT believes that the reliability objective is to ensure that there is continuity between the limits and criteria used in the Planning Assessments with the limits and criteria (i.e., SOLs) that are used in operations. This adds further clarity that it is the RCs and TOPs – not the PCs and TPs – who determine the SOLs and IROLs that are used in operations. However, the RCs and TOPs may use the information provided by PCs and TPs, especially with regard to risks for System instability, Cascading, and uncontrolled separation, when developing the SOLs and IROLs used in operations. Proposed FAC-015-1 Requirement R6 retains this concept, which is currently in FAC-014-2 Requirement R6, and appropriately points to the TPL-001-4 Reliability Standard rather than FAC-010.

Another key difference in the proposed new construct is seen in the PC's and TP's role in addressing instability and the establishment of IROLs. Under the current construct, PCs and TPs are responsible for identifying stability SOLs and IROLs in accordance with the PCs Methodology. As stated above, there is little value in the establishment of SOLs and IROLs (by current definitions a "value" such as MW, Mvar, etc.) for use in the planning horizon; however, there is great value identifying more severe System risks in the planning horizon and communicating those risks to the impacted entities who operate those systems. PCs and TPs are currently responsible for identifying more severe System impacts such as Cascading, voltage instability, or uncontrolled islanding in accordance with TPL-001-4 Requirements R3.4, R3.5, R4.4, and R4.5. The new FAC-015-1 requires continuity in the criteria used and requires that the PC and TP communicate these risks of System instability, Cascading or uncontrolled separation identified in its Planning Assessment to impacted RCs and impacted TOPs. The entities that operate those systems can then use that information, if applicable and appropriate, to assist in establishing stability limits and IROLs that will ultimately be used in operations.

SOLs in the planning horizon are developed starting with a model that has all facilities in service and has different system conditions (different transfers, weather assumptions, load levels) than those in the operations time horizon. The results from the planning horizon SOL methodology application can therefore be quite different and either do not correspond to SOLs (different limiting elements) in the operations time horizon or have very different limiting results (voltage limit violations versus System instability). Therefore, there is little or no value to using planning horizon SOLs during operations horizon conditions.

The use of the word "Operating" within the term "System Operating Limit" when establishing limits in the planning horizon has created confusion as to which value is referred to when referencing "SOL". Is it the "planning horizon SOL" or the "operations horizon SOL"? Retiring FAC-010-3 and eliminating references to SOLs and IROLs in the planning horizon will eliminate this confusion.

Retirement of FAC-010-3

Background

The purpose of FAC-010-3 (System Operating Limits Methodology for the Planning Horizon) is to ensure that SOLs used in the reliable planning of the (BES are determined based on an established methodology or methodologies. This standard only requires a PC to have a documented SOL Methodology. FAC-014-2 Requirements R3, R4, R4.3 and R5.4 require its use. Retirement of FAC-010-3 would consequently necessitate retirement of the associated requirements in FAC-014-2.

Comprehensive Requirements of TPL-001-4

The requirements in the TPL-001-4 standard require a comprehensive Planning Assessment and includes the establishment of limits and criteria (Facility ratings, System steady-state voltage limits, and stability performance criteria) and the *methodology* used by the planners (TPL-001-4, Requirement R6) to identify System instability (Cascading, voltage instability, or uncontrolled islanding) for the planning horizon. TPL-001-4 requires that a summary of the results of the assessment (TPL-001-4, Requirement R2) and a list of critical Contingencies that are expected to produce the most severe System impacts (TPL-001-4, Requirement R4.5) be included in the Planning Assessment. Further, TPL-001-4, Requirement R8 requires that the Planning Assessment, which includes all of information listed above, be distributed to any functional entity that has a reliability related need, for which the RC qualifies.

With the introduction of TPL-001-4 in 2013, FAC-010-3 became redundant as TPL-001-4 *is an established methodology* used in the reliable planning of the BES. This comprehensive methodology describes how the transmission system should be studied, addresses the establishment of performance criteria, prescribes the outages that must be analyzed, identifies the outages that do not meet the performance requirements, and requires determination of the corrective actions that should be taken to ensure future system reliability. This established methodology meets and exceeds performance requirements identified in FAC-010-3 SOL methodology. The comprehensive nature of TPL-001-4 is seen in the following excerpts from the TPL-001-4 requirements, which correspond to FAC-010-3:

<u>Modeling</u>:

TPL-001-4, Requirement R1 – “Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment.”

<u>Criteria/Methodology</u>:

TPL-001-4, Requirement R5 – “Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.”

TPL-001-4, Requirement R6 – “Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.”

<u>Analyzed Events</u>:

TPL-001-4, Table 1 – “Steady State & Stability Performance Planning Events”

<u>Reporting</u>:

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TPL-001-4, Requirement R2 – "Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES."

TPL-001-4, Requirement R8 – "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request."

Corrective Action:

TPL-001-4, R2.7: "For the planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met."

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Prior Review of FAC-010

The June 2013 report from the Independent Experts Review Project identified FAC-010-2.1 Requirements R3, R4, and R5 as "Requirements Recommended for Retirement" in Appendix E of the report. Requirement R5 was retired effective January 21, 2014 as part of NERC's P81 project. The Independent Expert Review team consisted of five independent industry experts and a sixth participant from FERC. The relevant table entries are shown below.

FAC-010-2.1	R3.	More appropriate as a Guideline. This is a checklist.
FAC-010-2.1	R4.	More appropriate as a Guideline. Description of appropriate coordination does not rise to a Standard.
FAC-010-2.1	R5.	P81 Phase 1.

In addition, the Periodic Review Team under the NERC Project 2015-03 recommended retirement of FAC-010-3. Industry comments received and reviewed during the PRT efforts indicate significant support for the retirement of FAC-010-3 due to its redundancy.

Creation of FAC-015-1

Rationale for FAC-015-1

As noted above, the SDT identified consistency of the limits and criteria used in the planning and operations time horizons as an area in the Reliability Standards that could be improved. To that end, the SDT developed FAC-015-1 to require that the planners use limits and criteria in their Planning Assessments that are as limiting, if not more limiting, than the limits and criteria developed in accordance with the RC's SOL Methodology.

The Perceived "Gap"

The perceived *gap* stems from the concern about the potential use of limits and criteria in the planning horizon that is less conservative than that used in the operations time horizon. For example, if planners used less conservative thermal limits when planning the System to meet all-facilities-in-service, peak load conditions, then operations would potentially face Facility Rating exceedances, which may require corrective actions up to and including Load shed to operate within Facility Ratings. Failing to have limit and criteria consistency between planning and operations may result in unacceptable System performance in the operations time horizon for the same conditions that were previously deemed acceptable when assessed in the planning horizon (i.e. planning the System less conservatively than the System is operated).

There is currently no mechanism to require consistency between the limits and criteria used in the two time horizons. By requiring a direct link of coordination between the limits and criteria in the SOL Methodology in the operations horizon with the limits and criteria used in Planning Assessments, which are used for the reliable planning of the BES, reliability and consistency is improved. By retiring FAC-010-3 the coordination is directly linked and a risk for a third and potentially disparate "methodology" around limits and criteria is also removed.

Development of FAC-015-1

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Despite the comprehensive requirements in TPL-001-4 and to address the perceived gap, the SDT developed FAC-015-1 with the title "Coordination of Planning Assessments with the RC's SOL Methodology" and the purpose "to ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the RC's SOL Methodology." FAC-015-1 will require the PC to implement processes that ensure that the Facility Ratings, voltage limits, and stability performance criteria used in its planning assessment are equal or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria specified in the RC's SOL Methodology.

Improved Communication of Limits and Criteria Between Planning and Operating Entities

Reliability Standard FAC-014-2 Requirements R5 and R6 address communication of limits and criteria between the planning (PCs and TPs) and operating entities (RCs and TOPs). The requirements lack some clarity with respect to timing of the communication. In proposed FAC-014-3, the SDT revised Requirements R5 and R6 to simplify and streamline the PC's and TP's responsibilities for communication of limits and criteria. Proposed FAC-015-1 coordinates with proposed FAC-014-3 by identifying the necessary communication of limits and criteria between the planning and operating entities that utilize such limits and criteria. These two standards also recognize existing requirements that already address some of the necessary communication (e.g. IRO-010-2, TOP-003-3, and IRO-014-3).

The SDT is improving clarity and efficiency of communications by establishing a single point of contact between the RC and the PC for communication of SOLs from the operations horizon to the planning horizon. The PC, which is more familiar with and interacts regularly with TPs, is the entity responsible for communicating the SOLs to impacted Transmission Planners. This removes communications directly from the RC to the TPs and keeps the PC in the direct path of all SOLs from the operations time horizon. The requirements for FAC-015-1 can be thus met during times of annual preparation for its annual Planning Assessments.

The figure below shows examples of how the communication of SOLs would work given the proposed FAC-014-3 and FAC-015-1. The figure details what is communicated, direction of the communication (i.e. from whom to whom), and the respective NERC Reliability Standard Requirements that require or contain a provision for such communication. Requirements that are struck through and grayed out represent currently-effective requirements that are proposed to be replaced and/or not be retained (due to redundancy with the other referenced requirements) in FAC-014-3. Requirements that are bold and red text are proposed requirements that support or replace existing requirements for the noted communication path and content.

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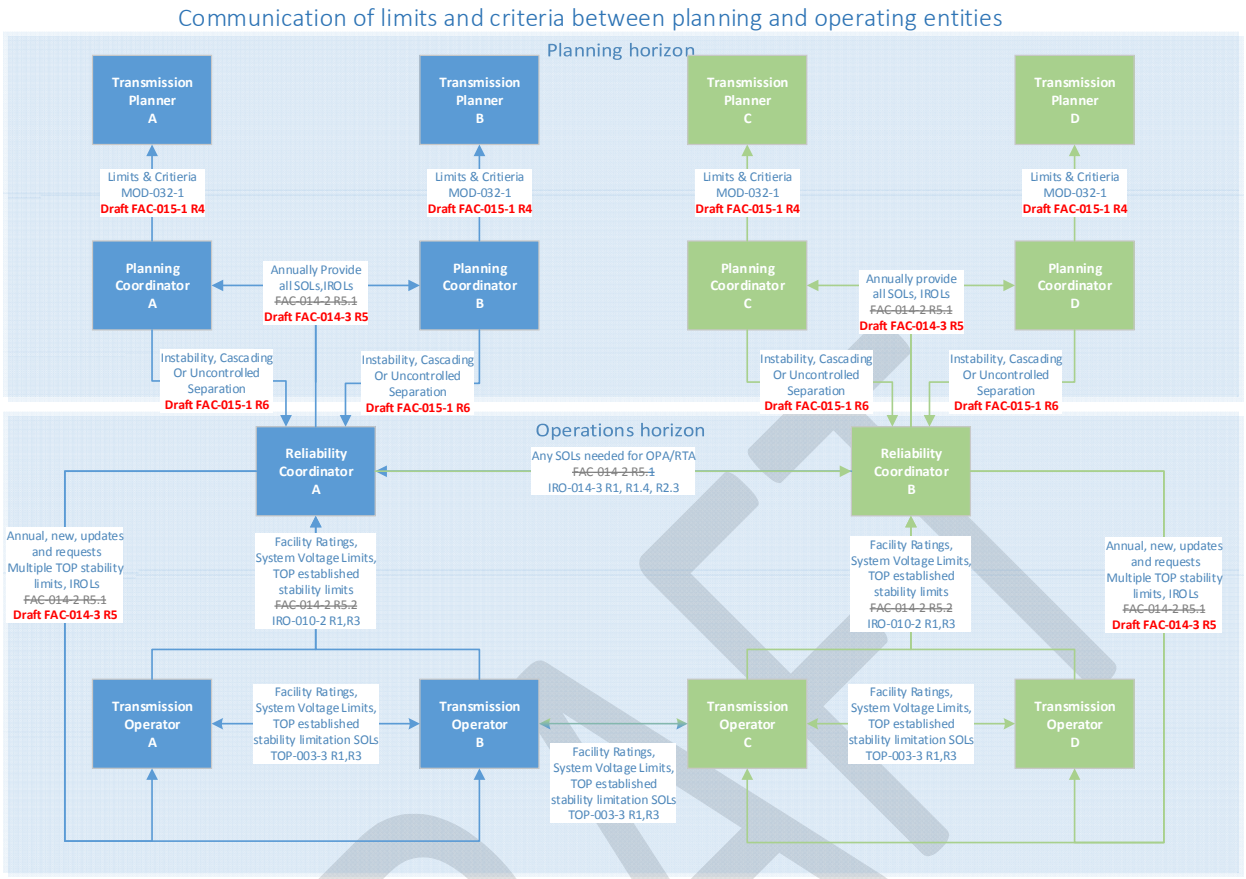

FAC-015 single standard for PCs and TPs

Currently, planning entities (PCs and TPs) have requirements in FAC-010-3 and FAC-014-2. With FAC-010-3 and FAC-014-2 Requirements R3, R4, R5.3 and R5.4 being effectively replaced by proposed FAC-015-1, the communication of stability related information identified in FAC-014-2 Requirement R6 from the PC to the RC remained. The SDT has opted to relocate the content addressed in FAC-014-2 Requirement R6 into newly proposed FAC-015-1 Requirement R6 rather than keep in FAC-014. This relocation allowed for all PC and TP requirements related to coordination of limits utilized between planning and operations time horizons to be in a single standard.

Proposed Definition of "System Voltage Limit"

Term: "System Voltage Limit"

Definition:

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

Rationale

As noted above, the Project 2015-09 standard drafting team (SDT) also proposes to add the term System Voltage Limit to the NERC Glossary with the following definition:

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

The SDT identified a need to develop a NERC Glossary definition for the term System Voltage Limit to address confusion within industry as to what constitutes a system voltage limit. As part of its informal comment period on initial drafts of FAC-011-4 and FAC-014-3 (July 14- August 12, 2016), the SDT requested industry comment on whether there is a need to clarify what constitutes system voltage limits through a defined term in the NERC Glossary. The SDT proposed the following definition: "The maximum and minimum steady-state voltages (both Normal and Emergency) that provide for reliable system operations."

The vast majority of commenters indicated support for developing a definition for System Voltage Limits but noted a few concerns with the proposed definition. In response to those comments, the SDT made the following revisions:

- The word "limits" was added to clarify that it is a numeric value.
- The terms "Normal" and "Emergency" were changed to lower case as "Normal" is not defined in the NERC Glossary, and the SDT concluded that the NERC defined term "Emergency" was not appropriate.
- The phrase "reliable system operations" was replaced with "acceptable System performance" because the SDT determined that this language was more reflective of the desired intent behind the definition.
- The SDT used the NERC Glossary term "System" as the definition implies that System Voltage Limits should result in acceptable performance (from a voltage perspective) of the overall System.

The proposed System Voltage Limit definition does not specify whether the Transmission Operator would be required to provide a "System Voltage Limit" for each bus on its system, or if the Transmission Operator would need to provide a single high and low limit that is applicable to its entire system. The SDT intends for the Reliability Coordinator's System Operating Limits (SOL) Methodology to dictate the manner in which

System Voltage Limits should be established. The proposed definition allows Reliability Coordinators to have such flexibility, provided the requirements in proposed FAC-011-4 are met.

Additionally, the System Voltage Limit definition allows for differing time components that may be associated with short term or dynamic ratings. The SDT's intent is to allow the flexibility to establish System Voltage Limits consistent with the Reliability Coordinator's SOL Methodology, provided the requirements in proposed FAC-011-4 are met. The proposed definition specifies that System Voltage Limits must include normal and emergency maximum and minimum limits, and that these limits provide for acceptable System performance (in the context of voltage performance). According to the definition, it is acceptable for a Reliability Coordinator's SOL Methodology to allow for System Voltage Limits to include a normal limit and multiple emergency limits, which may have associated time values similar to the way emergency Facility Ratings are associated with time values. As discussed below, this concept is supported by the proposed definition of SOL Exceedance which states, in relevant par: "Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to defined levels should the Contingency occur

Lastly, the proposed definition of System Voltage Limit does not explicitly distinguish between a voltage limit and a voltage rating. That is because proposed FAC-011-4 requires that System Voltage Limits respect equipment voltage ratings.

Potential Standards for Use of New Term: "System Voltage Limit"

These standard(s) were identified as potential areas that may benefit from the use of the new term. The SDT is in the process of evaluating these standards with respect to incorporating the definition.

- FAC-003-4 Transmission Vegetation Management
- MOD-001-2 Available Transmission System Capability
- PRC-012-2 Remedial Action Schemes
- TPL-001-4 Transmission System Planning Performance Requirements
- TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events
- VAR-001-4.1 Voltage and Reactive Control

Standard Development Timeline

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

Description of Current Draft

This is the ~~third~~ fourth draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	February 10- March 13, 2017
45-day formal comment period with initial ballot	July 27 – September 11, 2017
45-day formal comment period with additional ballot	October 27 – December 11, 2017
45-day formal comment period with additional ballot	March 16 – April 30, 2018
45-day formal comment period with additional ballot	May 18 – July 2, 2018

Anticipated Actions	Date
~~45-day formal comment period with additional ballot~~	~~May 18 – July 2, 2018~~
10-day final ballot	July 30 – August 8, 2018
NERC Board	August 16, 2018

A. Introduction

1. **Title:** Cyber Security – Communications between Control Centers

2. **Number:** CIP-012-1

3. **Purpose:** To protect the confidentiality and integrity of Real-time Assessment and Real-time monitoring data transmitted between Control Centers.

4. **Applicability:**

   4.1. Functional Entities: The requirements in this standard apply to the following functional entities, referred to as "Responsible Entities," that own or operate a Control Center.

   4.1.1. Balancing Authority

   4.1.2. Generator Operator

   4.1.3. Generator Owner

   4.1.4. Reliability Coordinator

   4.1.5. Transmission Operator

   4.1.6. Transmission Owner

   4.2. Exemptions: The following are exempt from Reliability Standard CIP-012-1:

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

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

   4.2.3. A Control Center at a generation resource or Transmission station or substation that transmits to another Control Center Real-time Assessment or Real-time monitoring data pertaining only to the generation resource or Transmission station or substation at which the transmitting Control Center is located.

5. **Effective Date:** See Implementation Plan for CIP-012-1.

B. Requirements and Measures

R1. The Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between any applicable Control Centers. The~~is~~ Responsible Entity is not required to include ~~requirement excludes~~ oral communications in its plan. The plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. Identification of security protection used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between Control Centers;

1.2. Identification of where the Responsible Entity applied security protection ~~-~~for transmitting Real-time Assessment and Real-time monitoring data between Control Centers; and

1.3. If the Control Centers are owned or operated by different Responsible Entities, identify the responsibilities of each Responsible Entity for applying security protection to the transmission of Real-time Assessment and Real-time monitoring data between those Control Centers.

M1. Evidence may include, but is not limited to, documented plan(s) that meet the security objective of Requirement R1 and documentation demonstrating the implementation of the plan(s).

C. Compliance

1. Compliance Monitoring Process

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

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the ~~Compliance Enforcement Authority~~CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its ~~Compliance Enforcement Authority~~CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Responsible Entities shall keep data or evidence of each Requirement in this Reliability Standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The ~~Compliance Enforcement Authority~~CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Responsible Entity documented its plan(s) but failed to include one of the applicable Pparts of the plan as specified in Requirement R1.	The Responsible Entity documented its plan(s) but failed to include two of the applicable Pparts of the plan as specified in Requirement R1.	The Responsible Entity failed to document plan(s) for Requirement R1; Or The Responsible Entity failed to implement any Part of its plan(s) for Requirement R1, except under CIP Exceptional Circumstances.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Technical Rationale for CIP-012-1.

Implementation Guidance.

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to FERC Order No. 822	N/A

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT

Cyber Security – Communications between Control Centers

Technical Rationale and Justification for Reliability Standard CIP-012-1

~~March~~ May 2018

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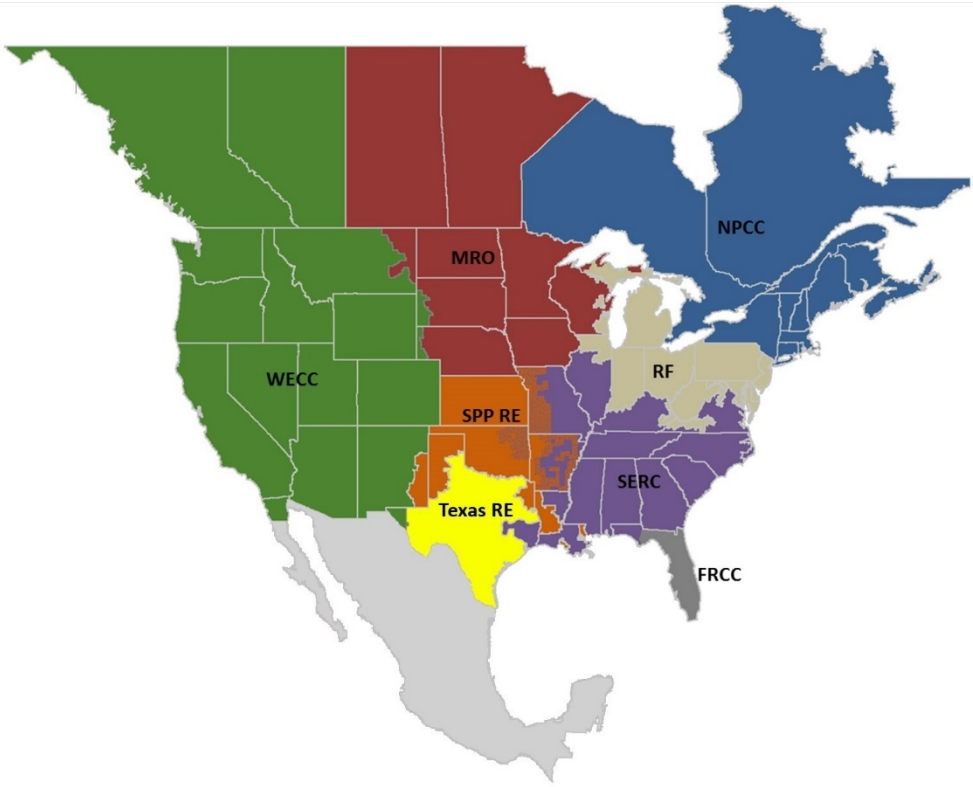
Preface

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

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



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

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard CIP-012-1. It will provide stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. It also contains information on the SDT's intent in drafting the requirements. This Technical Rationale and Justification for CIP-012-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

On January 21, 2016, the Federal Energy Regulatory Commission (FERC or Commission) issued Order No. 822, approving seven Critical Infrastructure Protection (CIP) Reliability Standards and new or modified terms in the Glossary of Terms Used in NERC Reliability Standards, and directing modifications to the CIP Reliability Standards. Among others, the Commission directed the North American Electric Reliability Corporation (NERC) to "develop modifications to the CIP Reliability Standards to require Responsible Entities[1] to implement controls to protect, at a minimum, communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact)." (Order 822, Paragraph 53)

In response to the directive in Order No. 822, the Project 2016-02 standard drafting team (SDT) drafted Reliability Standard CIP-012-1 to require Responsible Entities to implement controls to protect sensitive Bulk Electric System (BES) data and communications links between BES Control Centers. Due to the sensitivity of the data being communicated between Control Centers, as defined in the Glossary of Terms Used in NERC Reliability Standards, the standard applies to all impact levels (i.e., high, medium, or low impact).

Although the Commission directed NERC to develop modifications to CIP-006, the SDT determined that modifications to CIP-006 would not be appropriate. There are differences between the plan(s) required to be developed and implemented for CIP-012-1 and the protection required in CIP-006-6 Requirement R1 Part 1.10. CIP-012-1 Requirements R1 and R2 protect the applicable data during transmission between two separate Control Centers. CIP-006 Requirement R1 Part 1.10 protects nonprogrammable communication components within an Electronic Security Perimeter (ESP) but outside of a Physical Security Perimeter (PSP). The transmission of applicable data between Control Centers takes place outside of an ESP. Therefore, the protection contained in CIP-006-6 Requirement R1 Part 1.10 does not apply.

The SDT drafted requirements to provide Responsible Entities the latitude to protect the communication links, the data, or both to satisfy the security objective consistent with the capabilities of the Responsible Entity's operational environment.

CIP-012 Exemption (4.2.3) for certain Control Centers

As the SDT drafted CIP-012, it became aware of certain generating plant or Transmission substation situations where such field assets could be dual-classified as Control Centers based on the current Control Center definition. However, their communications to their normal BA or TOP Control Center are not the type of communications that are the intended scope of CIP-012 as they do not differ from any other generating plant or substation. The SDT wrote an exemption (Section 4.2.3 within CIP-012) for this particular scenario which is described in further detail below.

[1] As used in the CIP Standards, a Responsible Entity refers to the registered entities subject to the CIP Standards.

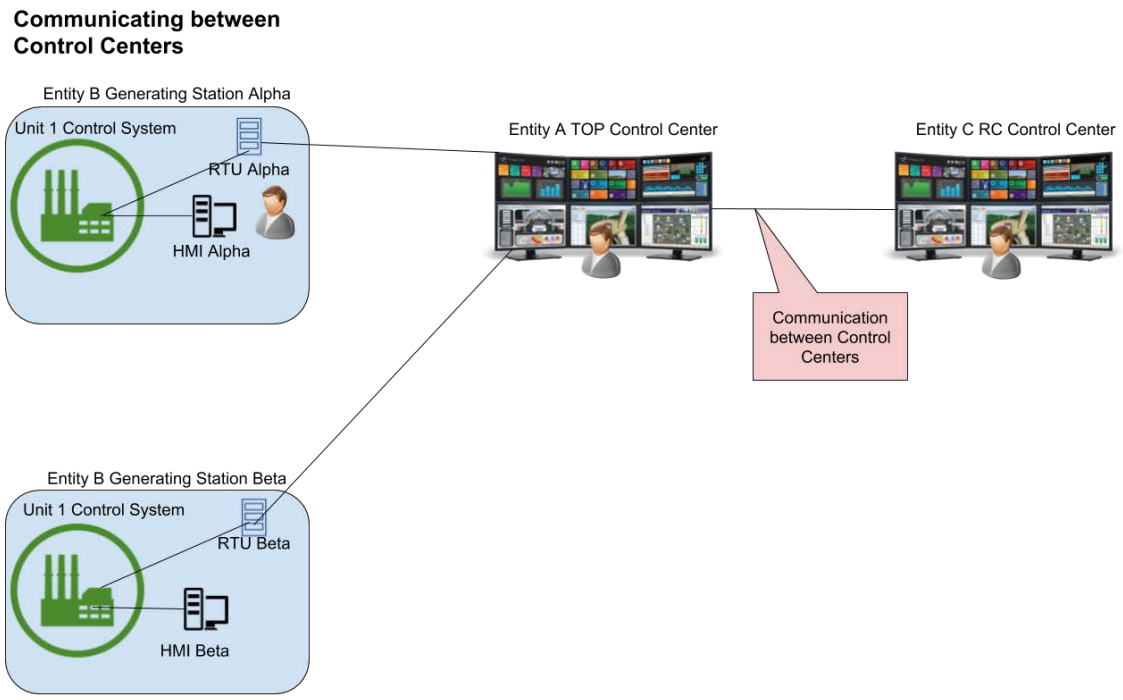


Figure 1

Figure 1 above pictures a typical scenario with two Control Centers communicating (in this instance Entity C's RC Control Center and Entity A's TOP Control Center). The communication between them is the intended scope of CIP-012's requirements if it meets the types of data inclusions and exclusions within the standard. The TOP Control Center is communicating with an RTU at two of Entity B's generating plants (Stations Alpha and Beta) and those RTU's are gathering information from each generating unit's control system. Each generating unit at each plant has an HMI (Human/Machine Interface; an operator workstation) that the local personnel use to operate their respective units.

Entity B decides that the generating unit at Station Beta, a small peaking facility, will only have an operator on site during the day and the operator at Station Alpha should be able to remotely start the unit at Station Beta if necessary.

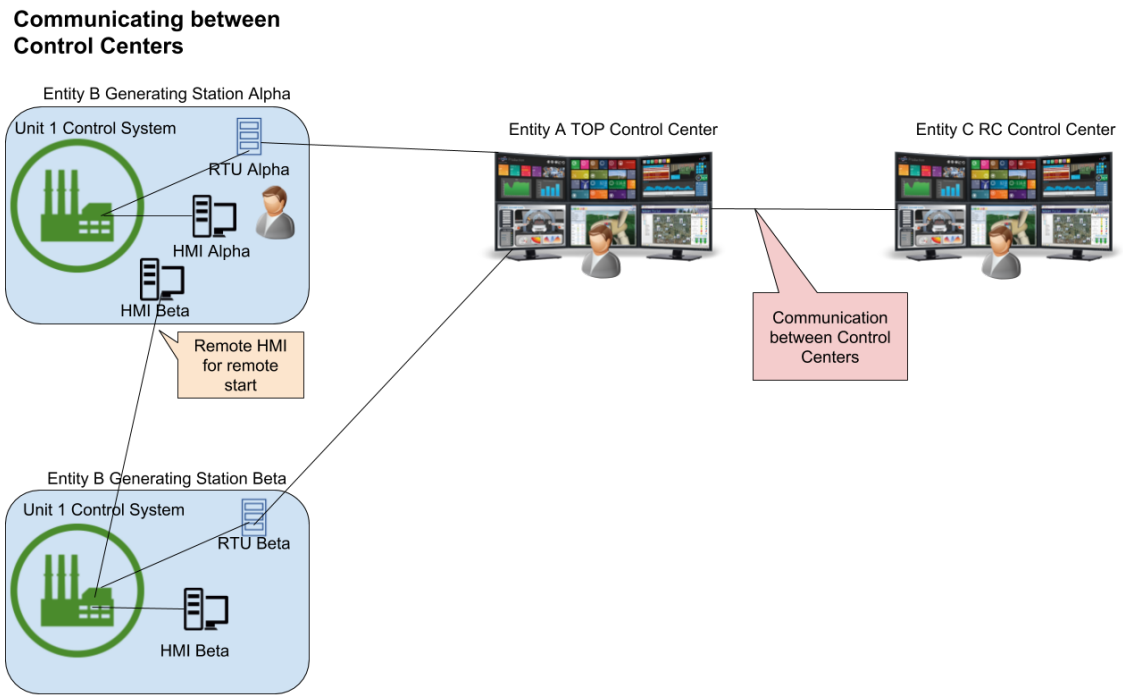


Figure 2

In Figure 2, Entity B installs a dedicated communications circuit from the control system on Station Beta's control system and puts a dedicated HMI at Station Alpha the operator can use. Station Alpha is now "one or more facilities hosting operating personnel that monitor and control the BES in real time to perform the reliability tasks of…a Generator Operator for generation Facilities at two or more locations." It can now be dual-classified not only as a generation resource but also as a Control Center.

The communications to the TOP and RC Control Centers from Figure 1 have not changed at all. –No new cyber systems are in place that can impact multiple units. -No cyber systems have been added performing Control Center functions. No additional risk from cyber systems has been added. -The only thing that has changed is an HMI for Station Beta has been moved within close physical proximity to an HMI for Station Alpha.

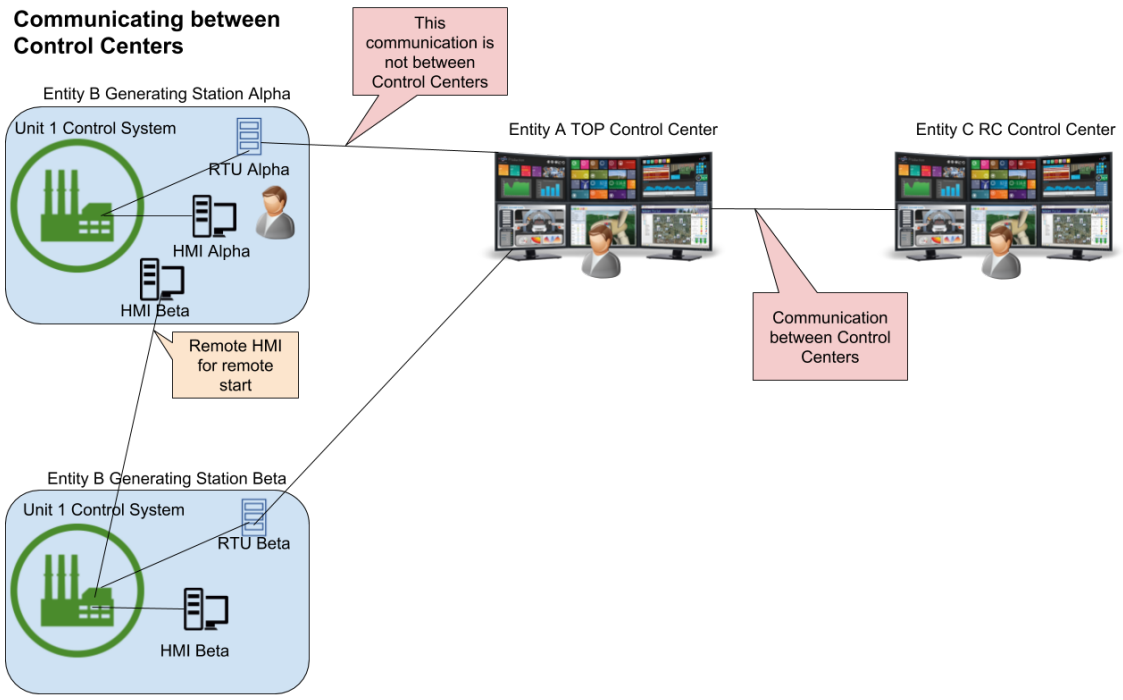


Figure 3

The SDT realized how this suddenly makes the communication noted in Figure 3 between Station Alpha and Entity A's TOP Control Center subject to CIP-012 although nothing has changed between them. —There is no new risk involved. -Two HMI's have been moved into the same room and suddenly a new NERC CIP standard applies to two entities.

This is an anamoly of the current Control Center definition defining a facility, room, or building from which something can be done without regard to how its done or with what systems. This is a generation specific example, but the SDT can envision substations with an HMI or protective relay that "operating personnel" within the substation could use to impact an adjacent substation. The SDT realizes that in the criteria for TO's and GOP's the "two or more geographic locations" is not a precise enough filter for capturing what a Control Center truly is. The SDT's attempts to address this issue by clarifying the definition of Control Center pointed out larger issues that are not within the SDT's SAR to address at this time. Therefore the SDT is handling the issue this creates for CIP-012 by the 4.2.3 exemption within the CIP-012 standard which reads:

> 4.2.3. ————A Control Center at a generation resource or Transmission station or substation that transmits to another Control Center Real-time Assessment or Real-time monitoring data pertaining only to the generation resource or Transmission station or substation at which the transmitting Control Center is located.
> ~~Control Centers located at a generation resource or Transmission station or substation that transmits Real-time Assessment and Real-time monitoring data to another Control Center and that data pertains only to the generation resource or Transmission station or substation at which the Control Center is located.~~

The intent of this exemption is to exclude the normal RTU-style communication from a field asset about that field asset's status from CIP-012. -Throughout this scenario or others like it, that communication has not changed and is still the same data pertaining only to the single location. -The SDT recognizes that this communication is not the

intent of the standard for protecting communications between Control Centers and this type of communications can be using older legacy communication technology and protocols.

Requirement R1

R1. The Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between any applicable Control Centers. ~~This requirement excludes oral communications.~~ The Responsible Entity is not required to include oral communications in its plan. ~~-~~The plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 *Identification of security protection used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring while being transmitted between Control Centers;*

1.2 *Identification of where the Responsible Entity applied security protection for transmitting Real-time Assessment and Real-time monitoring data between Control Centers; and*

1.3 *If he Control Centers are owned or operated by different Responsible Entities,identify the responsibilities of each Responsible Entity for applying security protection to the transmission of Real-time Assessment and Real-time monitoring data between those Control Centers.*

General Considerations for Requirement R1

Requirement R1 focuses on implementing a documented plan to protect information that is critical to the Real-time operations of the Bulk Electric System while in transit between applicable Control Centers. The SDT does not intend for the listed order of the three requirement parts to convey any sequence or significance.

Overview of confidentiality and integrity

The SDT drafted CIP-012-1 to address confidentiality and integrity of Real-time Assessment and Real-time monitoring data. This is accomplished by drafting the requirement to mitigate the risk of unauthorized disclosure (confidentiality) or modification (integrity). For this Standard, the SDT relied on the definitions of confidentiality and integrity as defined by National Institute of Standards and Technology (NIST):

- Confidentiality is defined as, "Preserving authorized restrictions on information access and disclosure, including means for protecting personal privacy and proprietary information."[2]
- Integrity is defined as, "Guarding against improper information modification or destruction, and includes ensuring information non-repudiation and authenticity."[3]

The SDT asserts that the availability of this data is already required by the performance obligation of the Operating and Planning Reliability Standards. The SDT drafted CIP-012 to address the data while being transmitted. The SDT maintains that this data resides within BES Cyber Systems, and while at rest is protected by CIP-003 through CIP-011.

Alignment with IRO and TOP standards

The SDT recognized the FERC reference to additional Reliability Standards and the responsibilities to protect the applicable data in accordance with NERC Reliability Standards TOP-003 and IRO-010. The SDT used these references to drive the identification of sensitive BES data and chose to base the CIP-012 requirements on the Real-time data specification elements in these standards. This approach provides consistent scoping of identified data, and does not require each entity to devise its own list or inventory of this data. Many entities are required to provide this data

[2] NIST Special Publication 800-53A, Revision 4, page B-3
[3] NIST Special Publication 800-53A, Revision 4, page B-6

under agreements executed with their RC, BA or TOP. The SDT asserts that typically the RC, BA or TOP will identify all data requiring protection for CIP-012-1 through the TOP-003 and IRO-010 Reliability Standards. However, the SDT noted that there may be special instances during which Real-time Assessment or Real-time ~~Monitoring~~ monitoring data is not identified by the RC, BA, or TOP. This would include data that may be exchanged between a Responsible Entity's primary and backup Control Center.

Identification of Where Security Protection is Applied by the Responsible Entity

The SDT noted the need for a Responsible Entity to identify where it will apply protection for applicable data. The SDT did not specify the location where CIP-012 security protection must be applied to provide latitude for Responsible Entities to implement the security controls in a manner best fitting their individual circumstances. This latitude ensures entities can still take advantage of security measures, such as deep packet inspection implemented at or near the EAP when ESPs are present, while maintaining the capability to protect the applicable data being transmitted between Control Centers.

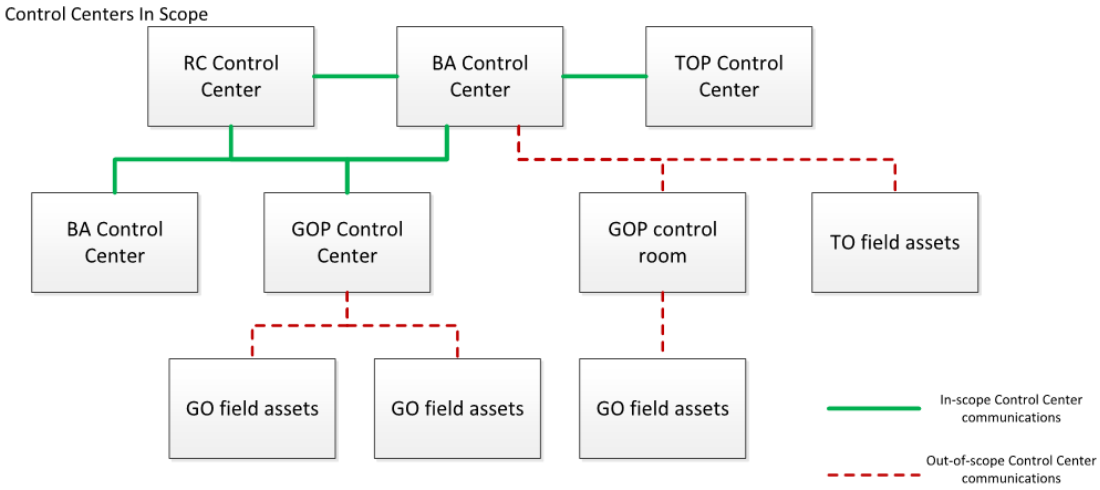
The SDT also recognizes that CIP-012 security protection may be applied to a Cyber Asset that is not an identified BES Cyber Asset or EACMS. The identification of the Cyber Asset as the location where security protection is applied does not expand the scope of Cyber Assets identified as applicable under Cyber Security Standards CIP-002 through CIP-011.

The SDT understands that in data exchanges between Control Centers, a single entity may not be responsible for both ends of the communication link. The SDT intends for a Responsible Entity to identify only where it applied security protection. The Responsible Entity should not be held accountable for identifying where a neighboring entity applied security protection at the neighboring entity's facility. A Responsible Entity, however, may decide to take responsibility for both ends of a communication link. For example, it may place a router in a neighboring entity's data center. In a scenario like this, where a Responsible Entity has taken responsibility for applying security protection on both ends of the communication link, the Responsible Entity should identify where it applied security protection at both ends of the link. The SDT intends for there to be alignment between the identification of where security protection is applied in CIP-012 R1, Part 1.2 and the identification of Responsible Entity responsibilities in CIP-012 R1, Part 1.3.

Control Center Ownership

The requirements address protection for Real-time Assessment and Real-time monitoring data while being transmitted between Control Centers owned by a single Responsible Entity. They also cover the applicable data transmitted between Control Centers owned by two or more separate Responsible Entities. Unlike protection between a single Responsible Entity's Control Centers, applying protection between Control Centers owned by more than one Responsible Entity requires additional coordination. The requirements do not explicitly require formal agreements between Responsible Entities partnering for protection of applicable data. It is strongly recommended, however, that these partnering entities develop agreements, or use existing ones, to define responsibilities to ensure the security objective is met. An example noted in FERC Order No. 822 Paragraph 59 is, "if several registered entities have joint responsibility for a cryptographic key management system used between their respective Control Centers, they should have the prerogative to come to a consensus on which organization administers that particular key management system."

As an example, the reference model below shows some of the data transmissions between Control Centers that a Responsible Entity should consider to be in-scope. The example does not include all possible scenarios. The solid green lines are in-scope communications. The dashed red lines are out-of-scope communications.



This reference model is an example and does not include all possible scenarios.

References

Here are several references to assist entities in developing plan(s) for protection of communication links:

- NIST Special Publication 800-53A, Revision 4: Security and Privacy Controls for Federal Information Systems and Organizations
- NIST Special Publication 800-82: Guide to Industrial Control Systems (ICS) Security
- NIST Special Publication 800-175B: Guideline for Using Cryptographic Standards in the Federal Government: Cryptographic Mechanisms
- NIST Special Publication 800-47: Security Guide for Interconnecting Information Technology Systems

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Cyber Security – Communications Between Control Centers

Implementation Guidance for CIP-012-1

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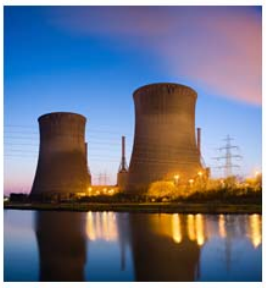

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Introduction

The Project 2016-02 SDT drafted this Implementation Guidance to provide example approaches for compliance with CIP-012-1. Implementation Guidance does not prescribe the only approach, but highlights one or more approaches that would be effective in achieving compliance with the standard. Because Implementation Guidance only provides examples, entities may choose alternative approaches that better fit their individual situations[1].

Responsible Entities may find it useful to consider this Implementation Guidance document along with the additional context and background provided in the SDT-developed Technical Rationale and Justification for CIP-012-1 document.

Background

The Commission issued Order No. 822 on January 21, 2016. Order 822 ~~approving seven~~approving seven CIP Reliability Standards and new or modified definitions, and directed modifications be made to the CIP Reliability Standards. Among other items, the Commission directed NERC to "develop modifications to the CIP Reliability Standards to require responsible entities to implement controls to protect, at a minimum, communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact)." (Order 822, Paragraph 53)

In response to the directive in Order No. 822, the Project 2016-02 standard drafting team (SDT) drafted Reliability Standard CIP-012-1 to require Responsible Entities to implement controls to protect sensitive Bulk Electric System (BES) data and communications links between BES Control Centers. Due to the sensitivity of the data being communicated between Control Centers, the standard applies to all impact levels (i.e., high, medium, or low impact).

The SDT drafted requirements to provide Responsible Entities the latitude to protect the communication links, the data, or both, to satisfy the security objective consistent with the capabilities of the Responsible Entity's operational environment.

[1] NERC's Compliance Guidance Policy

Requirements

R1. *The Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between any applicable Control Centers. ~~This requirement excludes oral communications~~The Responsible Entity is not required to include oral communications in its plan. The plan shall include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. Identification of security protection used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between Control Centers;

1.2. Identification of where the Responsible Entity applied security protection for transmitting Real-time Assessment and Real-time monitoring and control data between Control Centers; and

1.3. If the Control Centers are owned or operated by different Responsible Entities, identify the responsibilities of each Responsible Entity for applying security protection to the transmission of Real-time Assessment and Real-time monitoring data between those Control Centers.

General Considerations

Plan Development

As noted in the Technical Rationale and Justification for CIP-012-1, the focus of Requirement R1 is ~~-~~implementing a documented plan to protect information that is critical to the real-time operations of the Bulk Electric System while in transit between applicable Control Centers. The number of plan(s) and their content may vary depending on a Responsible Entity's management structure and operating conditions. The Responsible Entity may document as many plans as necessary to meet its needs. For instance, a Responsible Entity may choose to document one plan per Control Center or choose an all-inclusive, single plan for its Control Center communication environment. A Responsible Entity may choose to document one plan for communications between Control Centers it owns and a separate plan for communications between its Control Centers and the Control Centers of a neighboring Entity. The number and structure of the plans is at the discretion of the Responsible Entity as long as the plan(s) include the required elements described in parts 1.1, 1.2, and 1.3 of Requirement R1.

Identification of Security Protection

Entities have latitude to identify and choose which security protection is used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between Control Centers.

This security protection could consist of logical protection, physical protection, or some combination of both. To determine security protection, the requirement specifies that it must mitigate the risk of unauthorized disclosure or modification of applicable data.

Security protection implementation can be demonstrated in many ways. If a Responsible Entity uses physical protection, it may demonstrate implementation through review of an applicable Control Center floor plan with details subsequently confirmed through visual inspection, which identifies the physical security measures in place protecting the communication link. If the Responsible Entity uses logical protection, it may demonstrate implementation through an export of the device configuration which applies the security protection. Alternatively, a Responsible Entity may demonstrate implementation through security control monitoring, using an automated monitoring tool to generate reports on the encryption service used to protect a communications link. Where the operational obligations of an entire communication link, including both endpoints, belong to the Control Center of another Responsible Entity, the Responsible Entity without operational obligations for the communication link may demonstrate compliance by ensuring the communications link endpoint is within its Control Center, which could be limited to including the communication link endpoint within a PSP.

Identification of ~~-~~Where Security Protection is Applied by the Responsible Entity

A Responsible Entity should consider its environment when identifying where security protections should be applied. One approach is to implement security within the Control Center itself to ensure that data confidentiality and integrity is protected throughout the transmission. The Responsible Entity can identify where security protection is applied using a logical or physical location The application of security in accordance with CIP-012 requirements does not add additional assets to the scope of the CIP Reliability Standards. Locations of applied security protection may vary based on many factors such as impact levels of the Control Center, different technologies, or infrastructures. Where the operational obligations of an entire communication link, including both endpoints, belong to the Control Center of another Responsible Entity, the Responsible Entity without operational obligations for the communication link may demonstrate compliance by ensuring the communications link endpoint is within its Control Center, which could be limited to including the communication link endpoint within a PSP.

Identification of where a Responsible Entity applies security protection could be demonstrated with a list or a Control Center diagram showing either physical or logical security controls. Physical diagrams may require visual

confirmation of these controls. These diagrams or a list could be included within the plan developed for R1. A Responsible Entity could also use labels to identify on-site devices where CIP-012 security protection is applied.

When exchanging data between two entities, if a Responsible Entity only manages one end of a communication link, the Responsible Entity is not responsible for identifying where the security protection is applied by the neighboring entity with ~~whom~~which it is exchanging data. ~~–~~However, if a Responsible Entity has taken responsibility for both ends of the communication link (such as by placing a router within the neighboring entity's data center), then the Responsible Entity shall identify where the security protection is applied at both ends of the link.

Similarly, if a Responsible Entity owns and operates both Control Centers which are exchanging data (such as in the case of a primary and backup Control Center), then the Responsible Entity shall identify where security protection is applied at both ends of the link.

Identification of Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities

The Technical Rationale and Justification for CIP-012-1 identifies key considerations in the Control Center Ownership section when communications between Control Centers with different owners or operators. Many operational relationships between Responsible Entities are unique. Consequently, there is no single way to identify responsibilities for applying security protection to the transmission of Real-time Assessment and Real-time monitoring data between Control Centers.

Implementation of responsibilities could also be demonstrated in many ways. Some examples include a joint procedure, a memorandum of understanding, or meeting minutes between the two parties where responsibilities are defined.

Where the operational obligations of an entire communication link, including both endpoints, belong to the Control Center of another Responsible Entity, the Responsible Entity without operational obligations for the communication link may demonstrate compliance by ensuring the communications link endpoint is within its Control Center, which could be limited to including the communication link endpoint within a PSP. ~~–~~These responsibilities should be included in both Responsible Entities' plans satisfying requirement part 1.3.

Reference Model

For this Implementation Guidance, the SDT uses a basic reference model of Primary and Backup Control Centers (Entity Alpha) to illustrate approaches to demonstrating compliance. These Control Centers communicate to each other and to a neighboring entity's Control Center (Entity Beta) in configurations outlined by the diagrams in this section. The SDT recognizes that the reference model does not contain many of the complexities of a real Control Center. For this Implementation Guidance, the registration or functions performed in the reference model Control Center are also not considered. A high level block diagram of the basic reference model is shown below in Figure 1. -This Implementation Guidance is developed from the perspective of Entity Alpha.

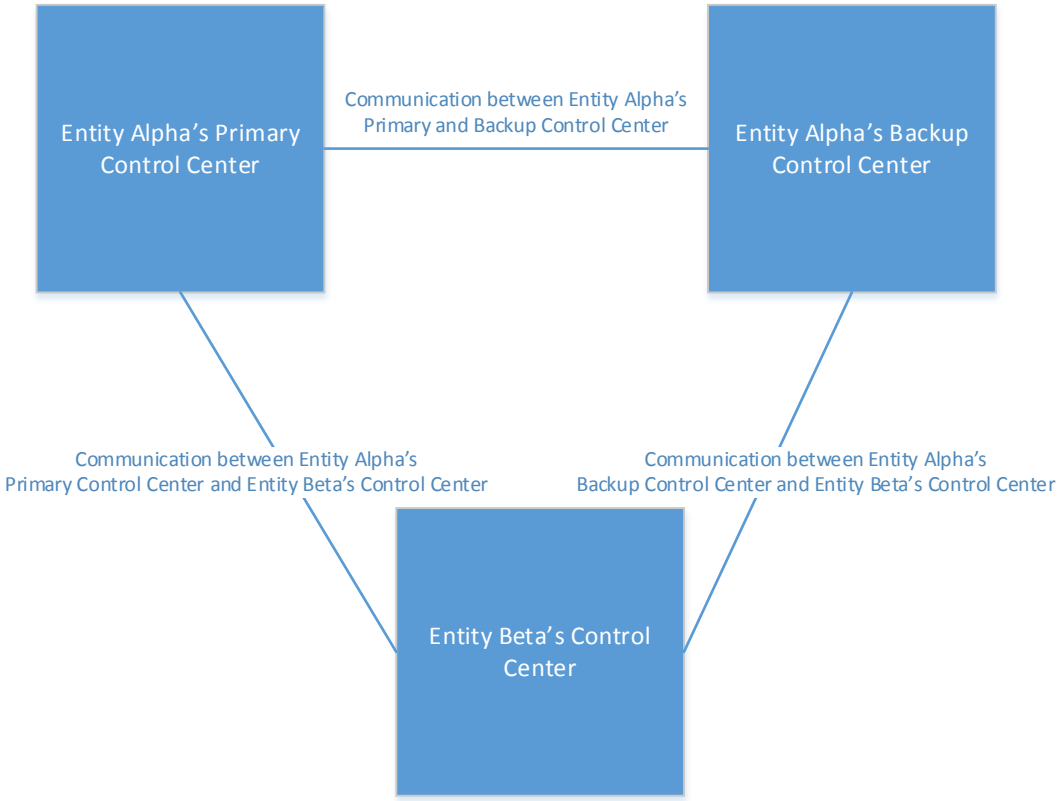

Figure 1: High Level Block Diagram of Reference Model Control Centers

Reference Model Discussion

Requirement R1 requires the implementation of a documented plan. To comply with requirement R1, one approach to a plan is to first determine which communications are in scope of CIP-012-1. There are multiple ways to identify an entity's scope in R1. For example, Entity Alpha in the reference model may first identify the Control Centers with which it communicates. Entity Alpha would determine that there are three: Entity Alpha's Primary Control Center, Entity Alpha's Backup Control Center, and Entity Beta's Control Center.– Entity Alpha does not need to consider whether Entity Beta further shares its data with another Entity. That is the responsibility of Entity Beta and is outside of Entity Alpha's purview. Additionally, Entity Alpha does not need to consider any communications to other non-Control Center facilities such as generating plants or substations. –These communications are out of scope for CIP-012-1.

Now that Entity Alpha has identified the Control Centers with which it communicates, Entity Alpha identifies either: (1) the Real-time Assessment and Real-time monitoring data; or (2) communication links which are used to transmit Real-time Assessment and Real-time monitoring data between Control Centers. In either case, Entity Alpha should refer to the data specification for Real-time Assessment and Real-time monitoring data identified in

TOP-003-3 and IRO-010-2. For this reference model scenario, identifying the communication links used to transmit Real-time Assessment and Real-time monitoring data may be the most straightforward approach. Through an evaluation of communication links between Control Centers and an evaluation of how it transmits and receives Real-time Assessment and Real-time monitoring data, Entity Alpha determined that it communicates applicable data between its primary and backup Control Centers across a single communication link. Entity Alpha also determined that it communicates applicable data to and from Entity Beta's Control Center across one of two links that originate from either Entity Alpha's primary or backup Control Center using the Inter-Control Center Communications Protocol (ICCP).

With an identified scope of communications links, Entity Alpha now considers the three required elements of its required communications between Control Centers for its plan.

Identification of Security Protection

- Entity Alpha must ensure that protection is applied where identified in its CIP-012-1 plan. The protection must also meet the security objective of mitigating the risk of unauthorized disclosure or modification of applicable data while in transit between Control Centers. The identification of security protection could be demonstrated by a network diagram similar to that shown in Figure 2 or Figure 3.
- In a simple case where the security protection is applied sufficiently close to the Control Center, such as within the Physical Security Perimeter of the Control Center, Entity Alpha may use a single security protection method to meet the security objective. For this case, shown in Figure 2, Entity Alpha implements a Virtual Private Network (VPN) connection across a private leased communication circuit for each of its three in-scope communication links. To meet the security objective, Entity Alpha further states that its VPN uses Internet Protocol security (IPsec) with encryption.
- For more complex scenarios, Entity Alpha may need to use a combination of security controls. ~~–~~For instance, in Figure 3, Entity Alpha uses a combination of physical security controls (physical access control) and logical security controls (encrypted communications consistent with the first scenario above) to meet the security objective.~~–~~ The SDT notes that the same technical architecture could exist where the responsibilities of the registered entities are different. ~~Alternately~~Therefore as shown in Figure 2 & 3, in the scenario where entity Alpha owns and operationally manages the communication link and endpoint equipment, Entity Beta is responsible for ensuring the communication endpoint of the communication link is within a Control Center. Entity Beta ensures Entity Alpha's communication link endpoint equipment is within a Control Center by including the communication endpoint within a Control Center PSP. ~~–~~The physical controls for the PSP are described in CIP-006 documentation and do not need to be repeated for this requirement. This satisfies Entity Beta's obligation for Part 1.1 and 1.2.
- While these scenarios are all specific to communication links, it is possible that Entity Alpha and Entity Beta achieve the security objective by applying protection to the data rather than the communication links. In this scenario, the application enabling the data exchange between Control Centers may be capable of applying security controls directly to the data. These security controls mitigate the risk of unauthorized disclosure or modification of applicable data rather than relying on lower level network services to provide this security. For instance, Entity Alpha and Entity Beta may apply security protection at the application layer by using Secure ICCP to exchange applicable data. According to a report released by Sandia National Labs[2], Secure ICCP provides "data integrity indirectly by providing a cryptographic checksum. Secure ICCP provides data confidentiality by encrypting ICCP data exchanges." Methods other than Secure ICCP could also be used to apply security protection to the data at the application layer.
- It is theoretically possible that Entity Alpha and Entity Beta could exchange Real-time Assessment data between Control Centers by email. In that scenario, one approach may be for Entity Alpha to email the

[2] https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/19-Secure_ICCP_Integration.pdf

applicable data to Entity Beta's Control Center in a protected container such as an encrypted zip file. Entity Alpha and Entity Beta can then exchange the password to that encrypted container through another method, such as by phone. While the notional example of protecting data exchanged by email is a useful illustration of how to achieve the security objective of CIP-012-1, it is extremely unlikely to be used in practice. The characteristics of email communication are inconsistent with the requirements of Real-time data exchange.

Identification of Where Security Protection is Applied by the Responsible Entity

Similar to the identification of security protection above, the identification of where security protection is applied can also be demonstrated by a network diagram similar to those found in Figures 2 and 3.

- Figure 2 shows the identification where CIP-012-1 security protection is applied for the Entity Alpha reference model when a single encrypted tunnel is used to implement the required protection. Entity Alpha has identified that security protection is applied at each of its Control Centers on the external Ethernet interface on the WAN router. While the diagram depicts where Entity Beta has applied security protection for illustrative purposes, Entity Alpha is not responsible for identifying where Entity Beta has applied security protection.

- In order to understand the application of security protection in context of who controls the communication link, it may be helpful to identify both where CIP-012-1 security protection is applied and the location of the telecommunications carrier (telco) demarcation point. Figure 3 provides such an example where the telco demarcation point may not be within the Control Center and based the facts and ~~circumstances surrounding this scenario, Entity Alpha has~~circumstances~~'~~ surrounding this scenario, Entity Alpha has implemented a combination of security controls to comply with CIP-012-1. In this scenario, Entity Alpha identifies that it has applied physical security protection for its PSP and continuing for its WAN router and that it has applied logical security protection (encryption) at the WAN router. Entity Alpha has also identified the telco demarcation point at a point in the telecommunications cabling connecting to Entity Alpha's WAN router, perhaps at a punch down block for example. In Figure 3, the telco demarcation point is inside the same room as the WAN router. The telco demarcation points are referenced in the drawing for clarity, but are not part of the plan.

- Figure 2 & 3 provides an example of where the operational obligations of an entire communications link, including both endpoints, belong to Entity Alpha. -In this case, Entity Beta may be responsible for ensuring the communications endpoint of the communications link is within their Control Center. Entity Beta ensures Entity Alpha's communication link endpoint equipment is within a Control Center by including the communication endpoint within a Control Center PSP. The documentation provided for Part 1.1 by Entity Beta fulfils this obligation.

- The data-centric scenario described above is less intuitive for identifying where security protection is applied by Entity Alpha. If security protection is applied at the application layer (such as Secure ICCP), Entity Alpha could reasonably identify the application or service applying the security (such as the Secure ICCP service) as the location of where security protection is applied.

Identification of Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities

Entity Alpha and Entity Beta may determine they each are responsible for one end of the VPN configuration on their respective WAN routers. Entity Alpha and Entity Beta have agreed to a 30 character pre-shared key for IPSec authentication.

Rather than use a pre-shared key, Entity Alpha and Entity Beta may decide to use digital certificates for the IPSec authentication using a trusted certificate authority. In that scenario, Entity Alpha and Entity Beta would agree on who is the party responsible for managing the certificate authority.

In the example where the communication link and endpoint equipment are owned by Entity Alpha, both entities should include ownership responsibilities in their plans satisfying requirement 1.3. Examples include but are not limited to, a letter ~~stating~~ indicating ownership or responsibility, a copy of a contract indicating ownership or responsibilities, an excerpt from an operational agreement or manual indicating ownership or responsibility.

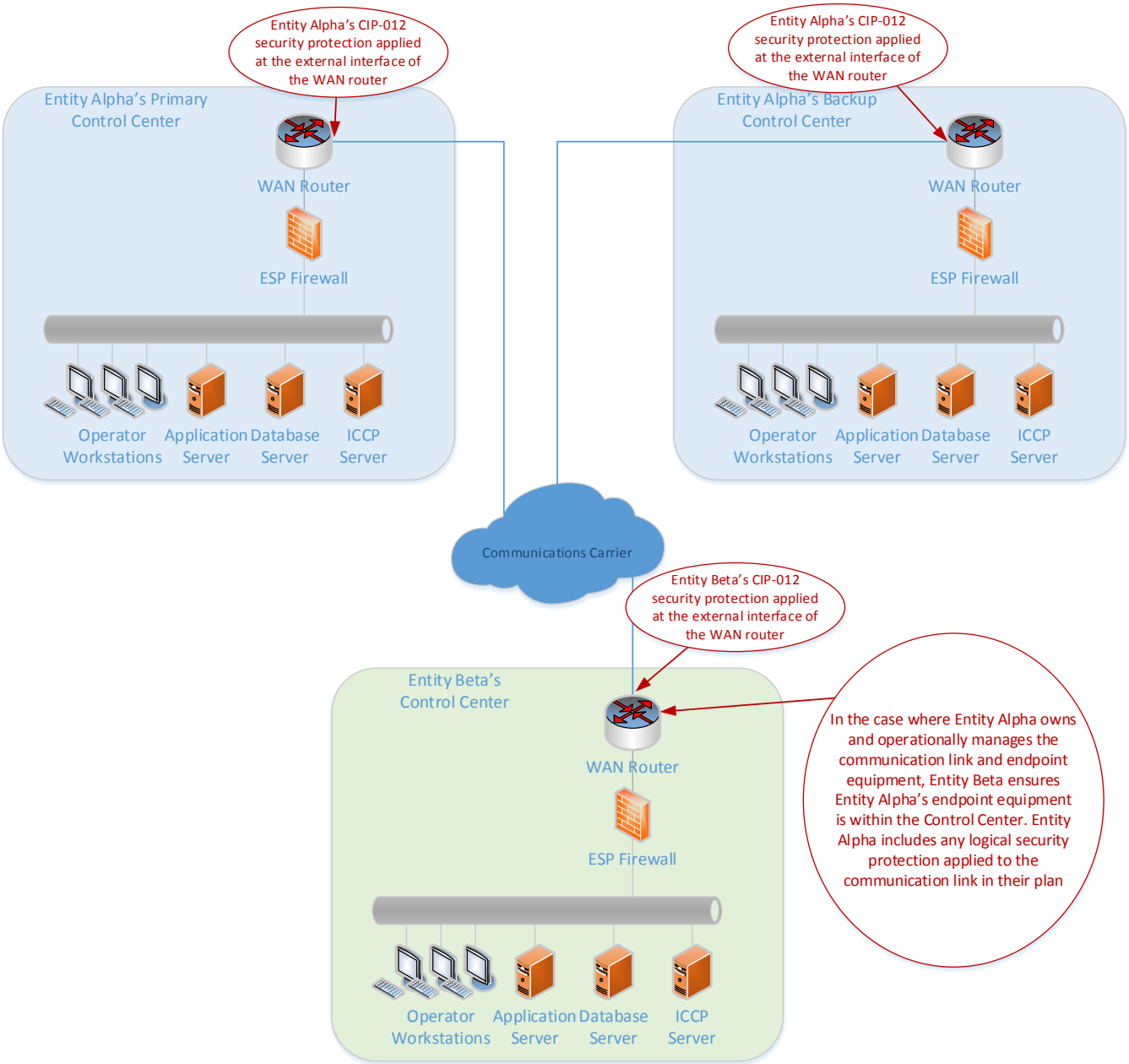

Figure 2: Network diagram and identification of where security protection is applied

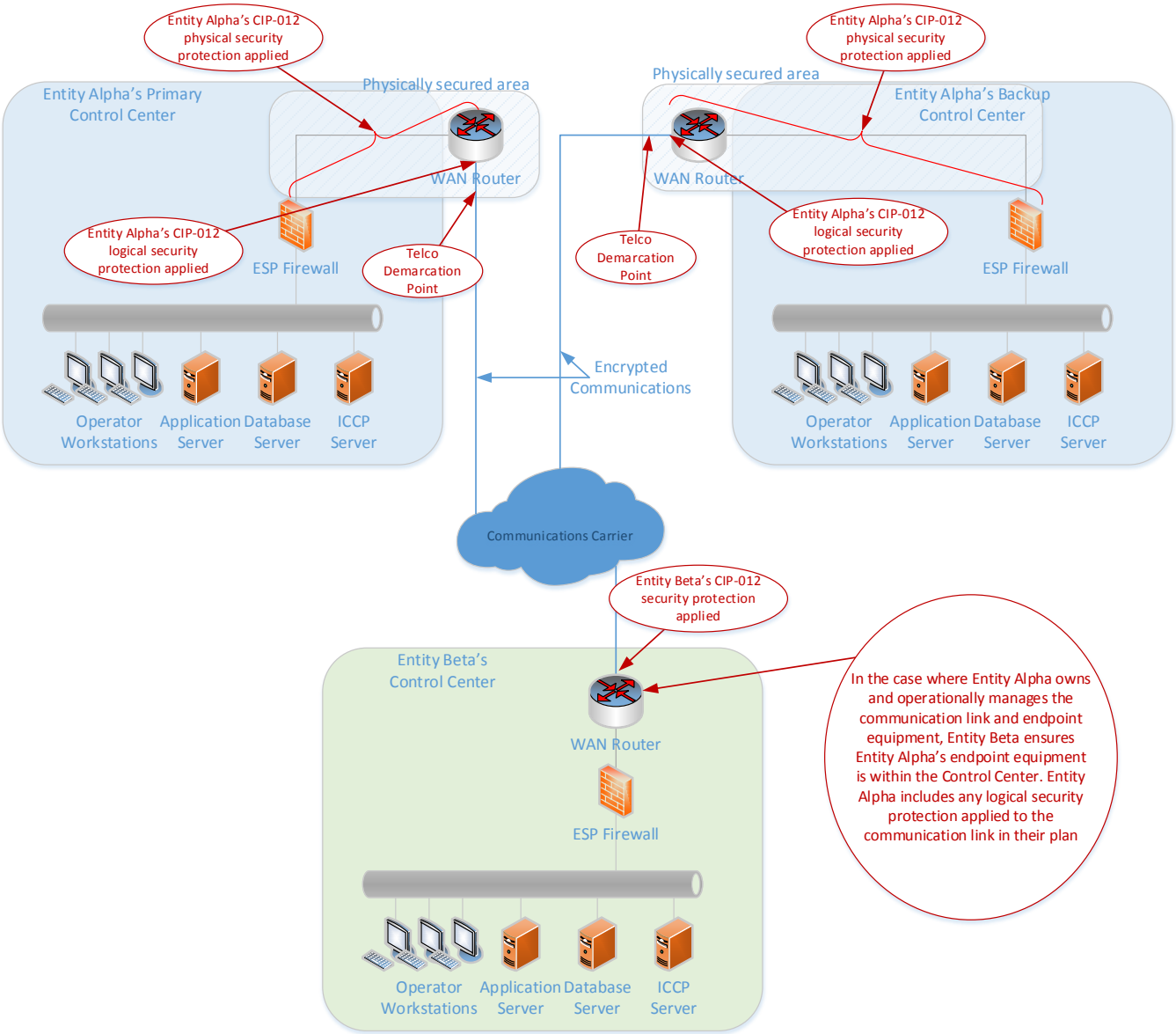

Figure 3: Network diagram using a combination of controls for CIP-012-1

References

Mitre Common Weakness Enumeration (CWE™) list of software weakness types
https://cwe.mitre.org/data/definitions/327.html

Cryptographic Standards and Guidelines
https://csrc.nist.gov/Projects/Cryptographic-Standards-and-Guidelines

NIST Special Publication 800-175B
Guideline for Using Cryptographic Standards in the Federal Government: Cryptographic Mechanisms
http://nvlpubs.nist.gov/nistpubs/SpecialPublications/NIST.SP.800-175B.pdf

Guide to Cryptography
https://www.owasp.org/index.php/Guide_to_Cryptography#Symmetric_Cryptography

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Implementation Plan

Project 2016-02 Modifications to CIP Standards
Reliability Standard CIP-012-1

Applicable Standard

- Reliability Standard CIP-012-1 - Cyber Security – Communications between Control Centers

Requested Retirements

- None

Prerequisite Standard

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Effective Date

Reliability Standard CIP-012-1 - Cyber Security – Communications between Control Centers

Where approval by an applicable governmental authority is required, Reliability Standard CIP-012-1 shall become effective on the first day of the first calendar quarter that is twenty-four (24) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard CIP-012-1 shall become effective on the first day of the first calendar quarter that is twenty-four (24) calendar months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **CIP-012-1**. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Guidelines for Violation Risk Factors

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

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

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

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

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

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

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for CIP-012-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium was assigned to this requirement. Cyber security plans enable effective implementation of the CIP standard's requirements to mitigate the risk of the unauthorized disclosure or modification of data used for Real-time Assessments and Real-time monitoring while being transmitted between Control Centers.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	N/A
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirement complements CIP-005-1, Requirement R1, CIP-006-6, Requirement R1, and CIP-007-6, Requirement R1 which are related to security of networks and communications components. The proposed VRF is consistent with these related requirements.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to have a cyber security plan would not, under Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion	N/A

VRF Justifications for CIP-012-1, Requirement R1	
Proposed VRF	**Medium**
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	

VSLs for CIP-012-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Responsible Entity documented its plan(s) but failed to include one of the applicable ~~p~~Parts of the plan as specified in Requirement R1.	The Responsible Entity documented its plan(s) but failed to include two of the applicable ~~p~~Parts of the plan as specified in Requirement R1.	The Responsible Entity failed to document plan(s) for Requirement R1; Or The Responsible Entity failed to implement any Part of its plan(s) for Requirement R1, except under CIP Exceptional Circumstances.

VSL Justifications for CIP-012-1 Requirements R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL does not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement is for the Responsible Entity to implement one or more documented plan(s) as specified in Requirement R1. The moderate VSL addresses where the Responsible Entity documented its plan(s) but failed to include one of the applicable parts of the plan as specified in Requirement R1. The high VSL addresses where the Responsible Entity documented its plan(s) but failed to include two of the applicable parts of the plan as specified in Requirement R1. The severe VSL addresses where the Responsible Entity failed to document plan(s) for Requirement R1, or where the Responsible Entity failed to implement plan(s) for Requirement R1.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, therefore, consistent with the requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

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Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	BAL-003-1.1 – Frequency Response and Frequency Bias Setting		
Date Submitted:			
SAR Requester Information			
Name:	David Lemmons – Chair of the Project 2017-01 BAL3 SAR Drafting Team		
Organization:	Project 2017-01 BAL3 SAR Drafting Team		
Telephone:	303.807.7949	Email:	David.Lemmons@ethosenergygroup.com
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The revisions to this standard are proposed to be approached in phases; however, the Standard Drafting Team (SDT) will determine the priority for each of the specific tasks. The revisions proposed in ~~the first~~ ~~p~~Phase I are intended only to correct inconsistencies identified through ~~use~~ implementation of the standard and to improve efficiencies and effectiveness of the administration associated with the standard. Revisions proposed for ~~the~~ ~~second~~ Phase II are modifications intended to align the standard more closely with its purpose.

SAR Information

Phase I

The supporting documents for BAL-003-1.1 were developed using engineering judgment on the data collection and process needed to determine the interconnection Frequency Response Obligation (IFRO), as well as the processing of raw data to determine compliance. Now that the standard is in place and the data is available for analysis, minor errors in assumptions, as well as process inefficiencies, have been identified. It is expected that as Frequency Response improves, the approaches embedded in the standard for annual samples may need to be modified.

~~In addition to fixing the inconsistencies outlined below, the drafting team may separate the administrative and procedural items and reassign them to an alternative process subject to Electric Reliability Organization (ERO) and North American Electric Reliability (NERC) Operating Committee approval.~~

The items that need to be addressed are to:

- Revise the IFRO calculation in BAL-003-1 due to issues identified in the 2016 Frequency Response Annual Analysis (FRAA) Report, such as the IFRO values with respect to Point C and varying Value B;
- Reevaluate the interconnections' Resource Contingency Protection Criteria;
- Reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12);
- Review and modify as necessary Attachment A of the Reliability Standard to remove administrative tasks and provide additional clarity, e.g., related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities; and
- Make enhancements to the BAL-003-1.1 FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data.

In addition to fixing the inconsistencies outlined above, the SDT may separate the administrative and procedural items and propose that they be reassigned to an alternative process subject to Electric Reliability Organization (ERO) and North American Electric Reliability (NERC) Operating Committee approval.

Phase II

The intent of the Reliability Standard is to ensure sufficient Frequency Response for each interconnection. Allocation of the responsibility to provide Frequency Response needs to reflect current conditions of the grid and correspond~~be commensurate~~ with the entities which provide and/or coordinate its provision.

- Both the IFRO calculations and the allocation of IFROs to reliability entities are retrospective (up to 2 years). The review should determine if there are alternate methodologies which consider

SAR Information
characteristics affecting Frequency Response (e.g., load response, mix and type of generation, Balancing Authority Area (BAA) footprint changes) to make allocation as equitable as possible; • Although Balancing Authorities (BAs) and FRSGs are responsible for coordination and/or management of Frequency Response from both resources and loads, response from resources is not addressed. The review should determine if additional reliability entities should have responsibility (e.g., Generator Operators (GOPs)) for provision of generator governor response); and • Review the measurement methodology of Frequency Response (both System and equipment level): o The Frequency Response Measure (FRM) should be reviewed to ensure that over-performance by one entity does not negatively impact the evaluation of performance by another.
Purpose or Goal (How does this request propose to address the problem described above?):
Phase I Review and revise the BAL-003-1.1 Reliability Standard and process documents to address the items listed in Phase I above. Additionally, the SDT should consider removing the supporting procedural and administrative processes from Attachment A ~~shall be considered~~ for incorporation into ERO-approved reference document(s) such that timely process improvements can be made as future lessons are learned. For additional information, please refer to the 2016 FRAA Report. **Phase II** Review and revise the BAL-003-1.1 Reliability Standard subsequent to Phase I and process documents to address the items listed in Phase II above.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
To address the issues with the Reliability Standard referenced above, including those that were described in the 2016 FRAA Report.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
Phase I During the 2016 annual evaluation of the values used in the calculation of the IFRO, the above-mentioned issues listed under Phase I were identified. The scope of the work will be to (1) address the inconsistency in the ratio of Point C to Value B, (2) reevaluate the Resource Contingency Protection

SAR Information
Criteria for each interconnection, (3) reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12), (4) clarify language in Attachment A, and (5) make enhancements to the BAL-003-1.1 FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data and identify opportunities to make current processes more efficient. For additional information on items #1, 2 and 3, please refer to the 2016 FRAA Report. **Phase II** The scope of the work will be to (1) revise the Reliability Standard to address the Real-time aspects of Frequency Response necessary to maintain reliability, (2) ensure comparability of and applicability to the appropriate responsible entities, (3) develop measurements to incorporate Real-time and resource and load characteristics, and (4) ensure equitability of performance measurement.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Phase I Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 1 of Phase I above through the standards development process to correct the inconsistency in the ratio of Point C to Value B. According to the FRAA Report, this ratio in the IFRO calculation couples Point C and Value B together, resulting in IFRO trends that do not align with the intent of the standard. Improvement in Value B with no change in Point C (improving recovery phase) would result in higher obligations to be carried, essentially penalizing improved recovery performance. Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 2 of Phase I above through the standards development process to modify the Resource Contingency Protection Criteria (RCPC). The RCPC for each interconnection should be revised to help ensure sufficient primary frequency response is maintained. The Eastern Interconnection uses the "largest resource event in last 10 years," which is the August 4, 2007 event. The ~~standard drafting team~~SDT should revisit this issue for modifications to the BAL-003-1 Reliability Standard, and the Resources Subcommittee (RS) should recommend ~~how~~ the criteria used to identify events ~~are selected~~ for each interconnection. Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 3 of Phase I above through the standards development process to revisit the frequency nadir point used in the calculation. Many events, particularly in the Eastern Interconnection due to its large synchronous inertia, tend to have a

SAR Information
frequency nadir point that exceeds the t_0 +12 seconds specified in BAL-003-1. Therefore, some events are characterized with a Point C value that is only partially down the arresting period of the event and does not accurately reflect the actual nadir. BAL-003-1 should be modified to allow for accurate representation of the Point C nadir value if exceeding beyond t_0+12 seconds. The actual event nadir can occur at any time, including beyond the time period used for calculating Value B (t_0+20 through t_0+52 seconds) and may be the value known as Point C' which typically occurs in the 72 to 95 second range after t_0. Consider revising BAL-003-1.1 Attachment A to provide clarity of intent giving particular attention to FRSGs and the timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities. Consider transferring supporting procedural and process steps from Attachment A into an ERO and NERC Operating Committee approved Reference Document or Reliability Guideline. Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 5 of Phase I above through the standards development process to provide enhancements of the FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data. **Phase II** Consider revising the BAL-003-1.1 Reliability Standard to: • Make the IFRO calculations and associated allocations 1) ~~be~~ more reflective of current conditions, 2) consider all characteristics affecting Frequency Response (e.g., load response, mix and type of generation), 3) include all applicable entities, and 4) be as equitable as possible; and • Make the FRM 1) ensure that over-performance by one entity does not negatively impact the evaluation of performance by another, 2) measure types/periods of response in addition to secondary Frequency Response, particularly primary Frequency Response, 3) include all applicable entities, and 4) make allocations as equitable as possible.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the end-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

Reliability Functions	
☐ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles		
Applicable Reliability Principles (Check all that apply).		
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.	
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.	
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.	
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.	
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.	
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.	
Does the proposed Standard comply with all of the following Market Interface Principles?		Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.		Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.		Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.		Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.		Yes

Related Standards	
Standard No.	Explanation
MOD-027-1	This standard applies to GOPs and requires verification of Turbine/Governor and Load Control or Active Power/Frequency Control Functions. Modifications to the BAL-003-1.1 Reliability Standard will need to coordinate with/complement MOD-027-1 to ensure there is no overlap or gap of requirements for governor performance.
EOP-005-2	Consider impacts to EOP-005-2.
BAL-001-TRE-1	Consider impacts to BAL-001-TRE-1.

Related SARs	
SAR ID	Explanation
None	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.

Regional Variances	
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.
WECC	None.

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review Team Preliminary Recommendation

FAC-008-3 Facility Ratings

Executive Summary

The Review Team completed a comprehensive review of FAC-008-3 – Facility Ratings. The team found the standard is sufficient to protect reliability and meets its reliability objective; however, there may be future opportunity to improve minor clarity and consistency issues. The observations and recommendations of the Review Team are documented below.

Introduction

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten (10) years, or once every five (5) years for Reliability Standards approved by the American National Standards Institute (ANSI) as an American National Standard.[1] The Reliability Standard identified above has been included in the current cycle of periodic reviews. The Review Team shall consist of two (2) subgroups; a Standing Review Team, which is appointed annually by the Standards Committee (SC) for periodic reviews, and a stakeholder Subject Matter Expert (SME) team. Consistent with Section 13 of the Standards Processes Manual (SPM)[2], the SC may use a public nomination process to appoint the stakeholder Subject Matter Expert (SME) team, or may use another method to appoint that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the periodic review, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the periodic review.

Together, the Standing Review Team and SME stakeholder team are the Review Team for a particular periodic review project and complete their portion of the template below.

The purpose of the template is to collect background information, pose questions to guide a comprehensive review of the standard(s) by the Review Team, and document the Review Team's considerations and recommendations. The Review Team will post the completed template containing its recommendations for information and stakeholder input, as required by Section 13 of the NERC SPM.

[1] American National Standards Institute website: https://www.ansi.org/ http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[2] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

Review Team Composition

	Standing Review Team	Plus Section 13 (SMEs):
Non-CIP Standards	Chairs of the following NERC Standing Committees[3]: • SC (Also the SC chair or his/her delegate from the SC will chair the Standing Review Team)[4] • Planning Committee • Operating Committee A regional representative will be included on the Standing Review Team. The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.	The SC will appoint stakeholder SMEs for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.
CIP Standards	Chairs of the following NERC Standing Committees[5]: • SC (Also the SC chair or his/her delegate from the SC will chair the Standing Review Team) • CIPC	The SC will appoint stakeholder SMEs for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.

The Review Team will use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation from one of the following three (3) choices:

1. Recommend re-affirming the standard as steady-state (Green); or
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard; however there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or

[3]Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.
[4] The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team's review of a standard s), and another SC member to chair a review of another standard(s).
[5] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to, or a retirement of, the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

A completed Periodic Review Template and any associated documentation should be submitted by email to Al McMeekin.

Applicable Reliability Standard: FAC-008-3 Facility Ratings
Team Members (include name and organization): 1. William Winters, Consolidated Edison Company of NY, Inc. 2. Josephine Daggett, Western Area Power Administration 3. Jeff Gruseck, Duke Energy 4. Kimberly Jursic, Georgia Power Company 5. Mario Kiresich, Southern California Edison 6. Hassib El Murdea, Ontario Power Generation 7. Brett Riedl, ComEd 8. Yaoyu Wang, American Electric Power
Date Review Completed:

Background Information *(to be completed initially by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) directives associated with the Reliability Standard? (*If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)*

   ☐ Yes
   ☒ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? (*If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard*.)

   ☐ Yes
   ☒ No

   Please explain:

3. Is the Reliability Standard one of the most violated Reliability Standards?

☐ Yes
☒ No

If so, does the cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes
☐ No

Please explain:

Questions for the Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff, as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

I. Quality

1. **Reliability Need, Paragraph 81:** Do any of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? *Use Attachment 2: Paragraph 81 Criteria to make this determination.*

   ☐ Yes
   ☒ No

   Please summarize your application of Paragraph 81 Criteria, if any:

2. **Clarity:** From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN or issue associated with it, or is frequently violated because of ambiguity?

   a. Does the Reliability Standard have obvious ambiguous language?

   b. Does the Reliability Standard have language that requires performance that is not measurable?

   c. Are the requirements consistent with the purpose of the Reliability Standard?

   d. Should the requirements stand alone as is, or should they be consolidated with other standards?

   e. Is the Reliability Standard complete and self-contained?

   f. Does the Reliability Standard use consistent terminology?

   ☐ Yes
   ☒ No

   Please summarize your assessment: **See Attachment 4.**

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

   ☐ Yes
   ☒ No

   Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), Violation Severity Levels (VSL) and Time Horizons) consistent with the direction of the Reliability Assurance Initiative (RAI) and FERC and NERC guidelines?

   ☒ Yes
   ☐ No

   If you answered "No," please identify which elements require revision, and why:

   See Attachment 4.

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard, or for coordination with other Reliability Standards?

   ☐ Yes
   ☒ No

   If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

   See Attachment 4.

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions or other factors?

   ☐ Yes
   ☒ No

   If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

7. **Practicable**:
   a. Can the Reliability Standard be practically implemented?

      ☒ Yes
      ☐ No

   b. Is there a concern that it is not cost effective as drafted?

      ☐ Yes
      ☒ No

   Please summarize your assessment of the practicability of the standard:

8. **Consideration of Generator and Transmission Interconnection Facilities:** Is responsibility for generator Interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

Guiding Questions:

a. If the Reliability Standard is applicable to Generator Owners (GOs) and/or Generator Operators (GOPs), is there any ambiguity about the inclusion of generator Interconnection Facilities? (If generation Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

Response: The standard is applicable to GOs. There is no ambiguity about the inclusion of generator Interconnection Facilities.

b. If the Reliability Standard is not applicable to GOs and/or GOPs, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, GOs that own and/or GOPs that operate relevant generator Interconnection Facilities should be explicit in the Applicability section of the Reliability Standard.)

Response: Not applicable.

c. If the Reliability Standard is applicable to Transmission Operators (TOPs) and/or Distribution Providers (DPs), is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

Response: Not applicable.

9. **Results-Based Standard (RBS):** Is the Reliability Standard drafted as a RBS?

☒ Yes
☐ No

If not, please summarize your assessment:

Guiding Questions:

a. Does the Reliability Standard address performance, risk (prevention) and capability?

☒ Yes
☐ No

b. Does the Reliability Standard follow the RBS format (for example, requirement and part structure) in Attachment 1?

☐ Yes
☒ No

c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard[6]?

☒ Yes
☐ No

[6] Ten Benchmarks of an Excellent Reliability Standard, posted at Page 626 of: http://www.nerc.com/pa/Stand/Resources/Documents/DT_Reference_Manual_Resource_Package_080114.pdf

II. Content

10. **Technical accuracy:** Is the content of the requirements technically correct, including identifying who does what and when?

☒ Yes
☐ No

If not, please summarize your assessment: **See Attachment 4.**

11. **Functional Model:** Are the correct functional entities assigned to perform the requirements consistent with the Functional Model?

☒ Yes
☐ No

If not, please summarize your assessment:
Applicability: Is there a technical justification for revising the Applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?

☐ Yes
☒ No

If so, please summarize your assessment:

12. **Reliability Gaps:** Are the appropriate actions for which there should be accountability included, or is there a gap?

☐ Yes
☒ No

If a gap is identified, please explain:

13. **Technical Quality:** Does the Reliability Standard have a technical basis in engineering and operations?

☒ Yes
☐ No

If not, please summarize your assessment:

14. **Does the Reliability Standard reflect a higher solution than the lowest common denominator?**

☒ Yes
☐ No

If not, please summarize your assessment:

15. **Related Regional Reliability Standards**: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide standard?

☐ Yes
☒ No

If yes, please identify the regional standard(s) and summarize your assessment:

Red, Yellow, Green Grading

Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow – is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the standard through the standards development process for retirement or revision. The reasons for the Review Team's conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team, minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow, or Red.

Recommendation

The answers to the questions above, along with its Red, Yellow, or Green grading and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its initial recommendation, and will document the final recommendation which will be presented to the SC.

Preliminary Recommendation *(to be completed by the Review Team after its review and prior to posting the results of the review for industry comment)*

☐ RE-AFFIRM *(This should be checked only if there are no outstanding directives, Interpretations or issues identified by stakeholders.) GREEN*

☒ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard; however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☐ RETIRE (Would include retirement of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment *(date):* 10/30/2017

Final Recommendation ***(to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation)***

☐ RE-AFFIRM *(This should be checked only if there are no outstanding directives, Interpretations or issues identified by stakeholders.) GREEN*

☐ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard; however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☐ RETIRE (Would include retirement of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR)*:

Date submitted to Standards Committee:

Attachment 1: Results-based Standards

Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[7] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

B2. Data Collection/Data Retention

These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

[7] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation

The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting

The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates

The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice

The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant

The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with

little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (*footnote omitted*)

C6. Is there any negative impact on the defense in depth protection of the BES?

The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?

The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Attachment 3: Independent Expert Evaluation Process

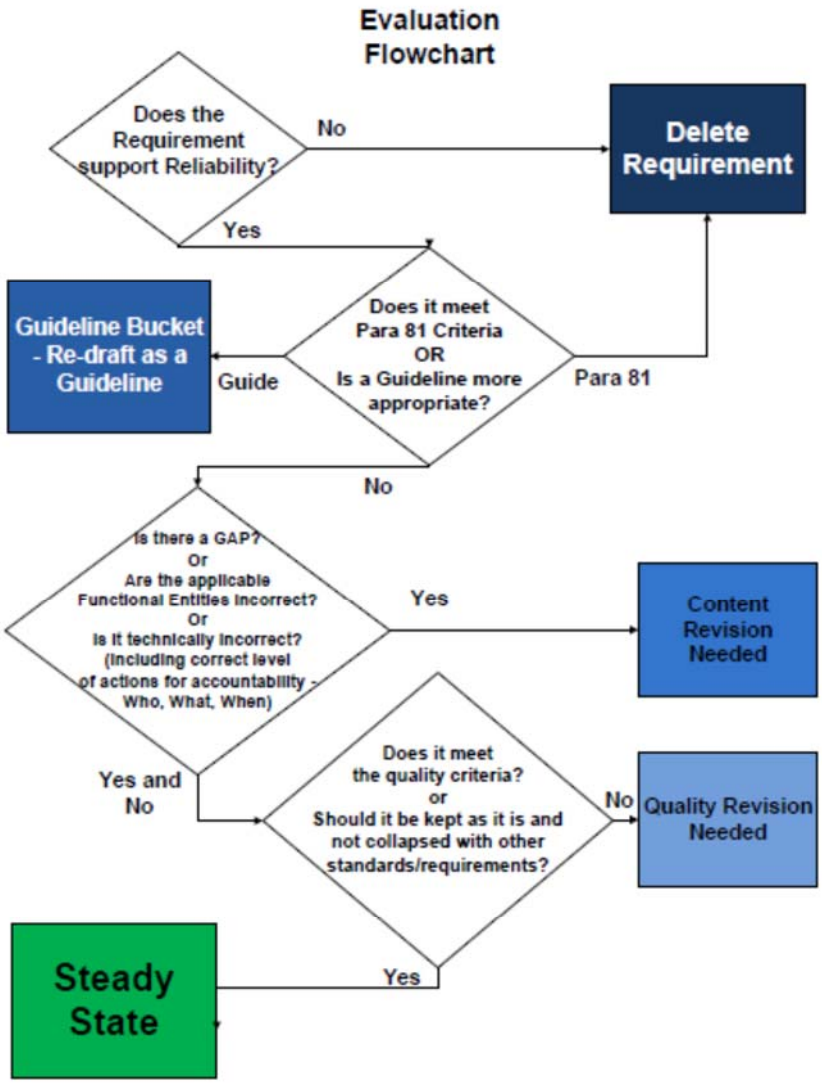

Figure 1: Evaluation Flow Chart

Attachment 4: Potential Revisions/Corrections

The Review Team consolidated a number of potential improvements that could be implemented by a drafting team should the standard be opened for revision. If you provide comments during the posting period regarding one of the team's observations, please reference the particular observation.

1) Paragraph 81 (None)

2) Clarity

   A. Requirement R1 and Requirement R2:
   Future consideration could be given to combining the requirements. The provision for Generator Owners to use documentation (e.g., design criteria or test data) for establishing Facility Ratings could be incorporated into the Facility Ratings methodology specified in Requirement R2.

   B. Requirement R2 and Requirement R3:
   Consider reordering the Parts of Requirements R2 and R3 in a more logical order, perhaps hierarchically from Facility Ratings to Equipment Ratings.

   C. Requirement R2, Part 2.1 and Requirement R3, Part 3.1:
   Consider replacing the term 'methodology' in Requirement R2, Part 2.1 and Requirement R3, Part 3.1 with the term 'methods' to prevent confusion. Using the term 'methodology' twice implies that two different documents (rather than a single document for Facility Ratings) are required.

   D. Requirement R2, Part 2.2 and Requirement R3, Part 3.2:
   Consider removing the word 'methods' as the 'methodology' is already addressed in Requirement R2, Part 2.1 and Requirement R3, Part 3.1. Parts 2.2 and 3.2 should be limited to the assumptions and design criteria.

   E. Requirement R2, Part 2.2.1 and Requirement R3, Part 3.2.1:
   Consider revising Parts 2.2.1 and 3.2.1 to state: "Industry standard(s) for establishing Equipment Ratings" since 'methodology' is already addressed in Parts 2.1 and 3.1.

   F. Requirement R2, Part 2.4 and Requirement R3, Part 3.4:
   Consider deleting the main body of Parts 2.4 and 3.4 as they seem redundant to Parts 2.1 and 3.1, respectively. Parts 2.4.1, 2.4.2, 3.4.1 and 3.4.2 are sufficiently independent and clear enough to be Parts 2.4, 2.5, 3.4, and 3.5, respectively.

   G. Requirement R7 and Requirement R8, Part 8.1:
   Consider replacing 'as scheduled by … requesting entities' with "on a mutually agreed upon schedule". According to the current language, a requesting entity could propose an unreasonable schedule which could impose a compliance burden on the provider.

3) Definitions (None)

4) Compliance Elements

   A. High VSLs Requirements R2 and R3:

Since Requirements R2 and R3 are identical, consider revising the language of the High VSLs to be identical.

5) Consistency with other Reliability Standards

   A. Requirement R1, Part 1.1:
   Consider adding the term 'Facility(ies)' after 'generator' to be consistent with the term 'Generator Facility(ies)' in the main body of Requirement R1.

   B. Requirement R1, Part 1.1, Requirement R2, Part 2.1, Requirement R3, Part 3.1:
   Consider making the language (of the three bullets) referencing industry groups (e.g. IEEE, ANSI, CIGRE) consistent across all requirements.

   C. Requirement R1, Part 1.2, Requirement R2, Part 2.3, Requirement R3, Part 3.3:
   Consider using "do not exceed" rather than "respect" for consistency and additional clarity.

   D. Requirement R2, Part 2.1 and Requirement R3, Part 3.1:
   Consider using the NERC Glossary term "Equipment Ratings" rather than "Ratings of the equipment that comprise the Facility".

   E. Measures M4 and M5:
   Update the text "(Retirement approved by NERC BOT pending applicable regulatory approval.)" to reflect FERC approval of retirement as stated with Requirements R4 and R5: "(Retirement approved by FERC effective January 21, 2014.)"

6) Changes Technology, System Conditions, or other Factors (None)

7) Practicable (None)

8) Consideration of Generator and Transmission Interconnection Facilities (None)

9) Results-Based Standard (RBS) (None)

10) Technical accuracy

   A. Requirement R2, Part 2.4 and Requirement R3, Part 3.4:
   Consider removing 'shunt compensation devices' from the list of equipment that comprises a Facility. Shunt devices are not series-connected devices. There are no thermal ratings and therefore are not considered in the Facility Rating as limiting equipment. The RSAW correctly focuses the auditor's attention on series-connected devices.

11) Functional Model (None)

12) Applicability (None)

13) Reliability Gaps (None)

14) Technical Quality (None)

15) Does the Reliability Standard reflect a higher solution than the lowest common denominator? (None)

16) Related Regional Reliability Standards (None)

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Standards Announcement

Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards

Periodic Review Team Nomination Period Open through May 15, 2017

Now Available

Nominations are being sought for periodic review team members through **8 p.m. Eastern, Monday, May 15, 2017**.

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

Previous drafting or periodic review team experience is beneficial, but not required. See the project page and unofficial nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the team July 2017. Nominees will be notified shortly after they have been appointed**.**

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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Standards Announcement

Project 2017-05 NUC-001-3 Periodic Review

Periodic Review Team Nomination Period Open through Tuesday, May 23, 2017

Now Available

Nominations are being sought for review team members through **8 p.m. Eastern, Tuesday, May 23, 2017.**

Use the electronic form to submit a nomination. If you experience any difficulties using the electronic form, contact Nasheema Santos An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

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

Periodic Review team members should expect to invest an average of approximately 10 hours per month for approximately 12 months to support this project. The first face-to-face meeting is tentatively planned for August 2017 in Atlanta, with one additional face-to-face meeting in North America, in addition to regular conference calls. Team members may also have supporting projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the Periodic Review effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

Previous team experience is beneficial but not required. See the project page and nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the team in July 2017. Nominees will be notified shortly after they have been appointed**.**

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Mat Bunch (via email) or at (404) 446-9785.

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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 Board of Trustees.

Description of Current Draft

Completed Actions	Date
SAR posted for comment	06/20/17 – 07/20/17

Anticipated Actions	Date
45-day formal comment period with initial ballot	February 2018 through March 2018
10-day final ballot	April 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

2. **Number:** BAL-002-32

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-32.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that the Responsible Entity:

- is a Balancing Authority experiencing a Reliability Coordinator declared Energy Emergency Alert Level or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous calendar years, unless directed by its

Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency.

	annually the Operating Process.			
R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document~~

CR Form 1

BAL-002-3 Rationales

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
2	January 19, 2017	FERC Order approved BAL-002-2. Docket No. RM16-7-000	
2	October 2, 2017	FERC letter Order issued approving raising the VRF for Requirement R1 and R2 from Medium to High. Docket No. RD17-6-000.	

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

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SAR posted for comment	06/20/17 – 07/20/17

Anticipated Actions	Date
45-day formal comment period with initial ballot	February 2018 through March 2018
10-day final ballot	April 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

2. **Number:** BAL-002-3

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-3.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

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- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

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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.

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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.

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1.3. Compliance Monitoring and Assessment Processes:

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	annually the Operating Process.			
R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

CR Form 1

BAL-002-3 Rationales

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
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1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
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Implementation Plan

Project 2017-06 Modifications to BAL-002-2

Requested Approvals

- BAL-002-3 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Requested Retirements

- BAL-002-2 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Applicable Entities

- Balancing Authority
- Reserve Sharing Group

Effective Date

The effective date for proposed Reliability Standard BAL-002-3 is provided below:

Where approval by an applicable governmental authority is required, Reliability Standard BAL-002-3 shall become effective the first day of the first calendar quarter that is six (6) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard BAL-002-3 shall become effective on the first day of the first calendar quarter that is six (6) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Current NERC Reliability Standards

The existing standard BAL-002-2 shall be retired immediately prior to the effective date of the proposed BAL-002-3 standard.

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Rationales for BAL-002-3

February, 2018

Requirement R1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is a experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time.

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

Rationale R1

Requirement R1 reflects the operating principles first established by NERC Policy 1 (Generation Control and Performance). Its objective is to assure the Responsible Entity balances resources and demand and returns its Reporting Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability. The SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

Commenters suggested a Quarterly Compliance similar to the current reports sent to NERC. The drafting team attempted to draft measurement language and VSL's for quarterly monitoring of compliance to R1. But the drafting team found that the VSL levels developed were likely to place smaller Balancing Authority's (BA) and Reserve Sharing Groups (RSG) in a severe violation regardless of the size of the failure. Therefore, the drafting team has not adopted a quarterly compliance calculation. Also, the proposed requirement and compliance process meets the directive in Paragraph 354 of Order 693.

The language in R1 part 1.3 does not specifically state under which EEA level the exclusion applies to reduce the need for consequent modifications of the BAL-002 standard. Thus, language in Requirement 1 Part 1.3.1 addresses both current and future EEA process. In addition, the drafting team has added language to R 1.3.1 clarifying that if a BA is experiencing an EEA event under

which its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance.

In addition, to address FERC Order No. 835, the drafting team has modified Requirement R1 Part 1.3.1 to clarify that the Responsible Entity, is the Balancing Authority (BA) notifying the Reliability Coordinator (RC) of the conditions set forth in Requirement R1, Part 1.3.1 in accordance with the Energy Emergency Alert (EEA) procedures. Under the Energy Emergency Alert procedures, the BA must inform the RC of the conditions and necessary requirements to meet reliability and the RC must approve of the information being provided before issuing an Energy Emergency Alert. Requirement R1 Part 1.3.1 requires the BA to provide additional information to the RC, allowing the RC to have a wide-area view of the state of the Bulk Electric System for possible future decisions concerning the System. It also provides for relief to a BA or RSG when reserves are being utilized under an EEA. These modifications keep the issues associated with Energy Emergencies within the Emergency Preparedness and Operations Standards, while allowing BAL-002-3 to compliment the process and clarify the narrow set of conditions where the BA and/or RSG is not subject to compliance to R1..

Requirement R2

Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.

Rationale R2

R2 establishes the need to actively plan in the near term (e.g., day-ahead) for expected Reportable Balancing Contingency Events. This requirement is similar to the current standard which requires an entity to have available a level of contingency reserves equal to or greater than its Most Severe Single Contingency.

Requirement R3

Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period.

Rationale R3

This requirement is similar to the existing requirement that an entity that has experienced an event shall restore its Contingency Reserves within 105 minutes of the event. Note that if an entity is experiencing an EEA it may need to depend on potential availability (or make ready for potential curtailment) of its firm loads to restore Contingency Reserve. This is the reason for the changes to the definition of Contingency Reserve in the posting.

Standard Authorization Request (SAR) Form

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

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

Requested information			
SAR Title:	Standards Alignment with Registration		
Date Submitted:			
SAR Requester			
Name:	Revised by Project 2017-07 Standards Alignment with Registration SAR Drafting Team Stephen Wendling, Chair		
Organization:	American Transmission Company		
Telephone:	(608) 877-8232	Email:	swendling@atcllc.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
This project will align the Reliability Standards with the outcome of the Risk-Based Registration (RBR) initiative.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project would modify Reliability Standards to be consistent with the FERC-approved changes to registration as part of the RBR initiative.			
Project Scope (Define the parameters of the proposed project):			
This project will review and align Reliability Standards impacted by the RBR initiative.			
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):			
This project will formally address any remaining edits to the Reliability Standards that are needed to align the existing standards with the RBR initiatives. The edits include updates to the BAL, CIP, FAC, INT, IRO, MOD, NUC, and TOP family of standards to remove the references to Purchasing-Selling Entities			

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

Requested information
(PSEs) and Interchange Authorities (IAs); references to the Load-Serving Entity (LSEs) will be removed or replaced by ~~either the Distribution Provider (DP), the Balancing Authority (BA), or~~ the appropriate functional ~~applicable~~ entity. ~~Additionally, t~~The project will include adding Underfrequency Load Shedding (UFLS)-only Distribution Providers (DPs) to the Applicability ~~Section~~ section of PRC-005 and PRC-006 per NERC registration criteria.~~; and review the Applicability sections of PRC-004 and PRC-008 and revise, as appropriate, to add UFLS-only DPs.~~ Additionally, the project will consider whether to include a definition for UFLS into the NERC Glossary of Terms, as well as review the standards to ensure consistent use of the term Planning Coordinator. The clean-up effort of the standards can be categorized into the following: 1. Modifications to existing standards where the removal of the retired function may need replacement by another function. For instance, Reliability Standard MOD-032-1 specifies certain data from LSEs that may need to be provided by other functional entities going forward. 2. Modifications where the applicable entity and references may be removed. These updates may be able to follow a similar process to the Paragraph 81 initiatives where standards are redlined and posted for industry comment and ballot. A majority of the edits would simply remove deregistered functional entities and their applicable requirements/references. The impacted standards include the BAL, CIP, IRO, and TOP family of standards. Additionally, PRC-005~~-1.1b~~ and PRC-006~~-003~~ will be updated to add UFLS-only DP to the Applicability ~~Sections~~sections. ~~and a review of the Applicability Sections of PRC-004-5(i) and PRC-008-0 to add, as appropriate, UFLS-only DP to align with the post-RBR registration impacts.~~ 3. Initiatives that can address RBR updates through the periodic review process. ~~-~~The 2017-07 SAR drafting team should consider whether it or the periodic review teams currently reviewing those standards should make the necessary revisions. ~~This would include the INT-004-3.1 and NUC-001-3 standards. Rather than the Project 2017-07 making the revisions the SDT could coordinate with the periodic review teams currently reviewing INT-004-3.1 and NUC-001-3 so that any changes resulting from those periodic reviews, if any, may be proposed at the same time after completion of each periodic review.~~
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
No additional costs outside of the time and resources needed to serve on the SAR and Standard Drafting Team.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.* Dispersed Generation Resources):
None
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.* Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):

Requested information
Since LSE is being removed or replaced by either the Distribution Provider (DP), the Balancing Authority (BA), or the appropriate Applicable Entity for the standards that need to be updated, those entities will likely be best suited for the MOD and PRC updates.
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
None
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes

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

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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
NPCC and SERC	~~UFLS-only DP will be added to the Applicability Section of PRC-006 and will create a variance of the following two~~ Regional Reliability Standards: PRC-006-NPCC-1 PRC-006-SERC-01 PRC-006-SERC-02

For Use by NERC Only

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

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	~~January X~~December 11, 2017	Standards Information Staff	Revised
3	February 1, 2018	Standards Information Staff	Revised

Standard 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 the appropriate functional entity. The project will include adding Underfrequency Load Shedding (UFLS)-only Distribution Providers (DPs) to the Applicability section of PRC-005 and PRC-006 per NERC registration criteria. 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 and PRC-006 will be updated to add UFLS-only DP to the Applicability sections. 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.
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):
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

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

Requested information
Are there 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
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	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	December 11, 2017	Standards Information Staff	Revised
3	February 1, 2018	Standards Information Staff	Revised

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	Canadian-specific Revision to proposed standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events)		
Date Submitted:	February 27, 2018		
SAR Requester			
Name:	Helen Lainis (IESO) and Payam Farahbakhsh (Hydro One)		
Organization:	Canadian Electricity Association ("CEA") Members from Ontario (IESO and Hydro One), with the support of additional CEA Members including Manitoba Hydro, Hydro Québec and SaskPower.		
Telephone:	Helen: 905-855-4106 Payam: 416- 345 - 5484	Email:	Helen: helen.lainis@ieso.ca Payam: Payam.Farahbakhsh@HydroOne.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☒ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The need for this SAR is to enable the option for Canadian Registered Entities to leverage operating experience, observed GMD effects and on-going research efforts for defining alternative Benchmark GMD Events and/or Supplemental GMD Events specific to their unique topology. Registered Entities from Ontario, Québec, Manitoba and Saskatchewan have indicated support for a revision to be included in TPL-007-2 as an option for Canadian Registered Entities to pursue. At a minimum, Registered Entities in Ontario (Hydro One and IESO) have indicated that this proposed			

Requested information
revision would be used to define and implement an alternative Benchmark GMD Event and/or Supplemental GMD Event that appropriately reflects their specific geographical and geological characteristics.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The goal is to enable Canadian Registered Entities to define and implement alternative Benchmark GMD Events and/or Supplemental GMD Events that appropriately reflects the specific geographical and geological characteristics of the Canadian provinces, including those located on the Canadian Shield, a vast area of igneous rock exhibiting low electrical conductivity, through leveraging ongoing research efforts, operating experience, and observed GMD effects: • Registered Canadian entities from Canadian provinces (most prominently Manitoba, Ontario and Québec) located on the Canadian Shield, are currently working to develop a Benchmark GMD Event and/or Supplemental GMD Event that takes into account their unique topology. • These Canadian Registered Entities have been researching the impact of GMD on their power systems for several years now, and have been collaborating with Natural Resources Canada to collect and analyze Canadian magnetometer data for their respective provinces.
Project Scope (Define the parameters of the proposed project):
Reliability Standard TPL-007-2 should be revised to allow Canadian jurisdictions to define and implement alternative Benchmark GMD Events and/or Supplemental GMD Events that are different from the ones defined in TPL-007-2 appropriate for a continent wide standard. The Benchmark GMD Event and/or Supplemental GMD Event described in TPL-007-2 should be options to pursue for Canadian Registered Entities for performing GMD Vulnerability Assessments. Implementation of Benchmark GMD Events and/or Supplemental GMD Events by Canadian Registered Entities should be subject to approval by applicable Canadian governmental authority or their agencies.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
NERC has spent a substantial amount of time and effort working with experts across the industry to develop scientifically sound Benchmark GMD Events defined in TPL-007-2 appropriate for a continent wide standard.

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

Requested information
The research and development in this field continues to evolve, and more remains to be learned, new assessment tools need to be developed and assessment models need to be verified. In Canada, there is on-going work being done on this subject. We request that TPL-007-2 provide the flexibility for Canadian jurisdictions to leverage their expertise and to build on their research and on GMD impact assessment methodologies to define alternative Benchmark GMD Events and/or Supplemental GMD Events targeted to their unique topology. The Canadian Shield is a sprawling rock formation that stretches across nearly all of Québec, much of Ontario and Manitoba, the northern portion of Saskatchewan and the northeast corner of Alberta. This geological formation blocks current from being dissipated into the Earth, making these Canadian provinces more susceptible to solar storms. As such, Registered Entities from several Canadian shield provinces have been researching the impact of GMD on the reliable operation of their BES for years. For example, Hydro One Networks Inc., has been conducting this work in Ontario, Manitoba Hydro has been conducting this work in Manitoba and Hydro Québec has been conducted this work in Québec. A list of several technical publications could be provided upon request of the SDT to demonstrate the depth of Hydro One's, Manitoba Hydro's, Hydro Québec's and other jurisdictions' technical research and expertise in modeling and analyzing GMD impacts. These references also describe significant development efforts on tools and operating processes to support planned transmission system performance during GMD events. Natural Resources Canada has published their calculations of extreme value statistics for a 1-50 and 1-100 year geomagnetic storm based on data from 13 Natural Resources Canada geomagnetic observatories, and Natural Resources Canada and Registered Entities from Canadian shield provinces have been collaborating to collect and analyze Canadian magnetometer data for their respective provinces.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost implications of addressing a Benchmark GMD Event and/or Supplemental GMD Event is expected to be more significant for the Canadian shield provinces than for those registered entities in the lower 48 state portion of the United States. Furthermore, any capital investment must be approved by the applicable provincial regulatory authority. Consequently, it is essential that the requirements of the standard appropriately reflect conditions that exist in affected Canadian provinces. To this end, Registered Entities from these provinces are working with Natural Resources Canada and are using their own inputs to develop a Benchmark GMD Event and/or Supplemental GMD Event based on empirical data that will form the basis for seeking approval for any required investments with their respective regulatory authorities.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.* Dispersed Generation Resources):
Not Applicable

Requested information
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.* Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Canadian Registered Entities that meet the applicability specified in Sections 4.1 and 4.2 of the proposed TPL-007-2 Reliability Standard.
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The revision would be used, at a minimum, by IESO and Hydro One to avoid needing to seek remand to TPL-007-2 in Ontario, Canada. Working with CEA, IESO and Hydro One have engaged other Canadian Registered Entities to solicit feedback. Registered entities from Manitoba, Québec and Saskatchewan are supportive of a to TPL-007-2 as an option for Canadian Registered Entities to pursue. No Canadian Entity has voiced opposition to such a revision.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
No
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
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Reliability Principles	
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber-attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	YES

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	

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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

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		

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253	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.82% Approval: 43.72%			
254	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.04% Approval: 38.56%			
255	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.53% Approval: 46.38%			
256	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1a	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.95% Approval: 92.41%	Support 4/16/12		
257	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28%% Approval: 75.44%			
258	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.02% Approval: 87.22%			
259	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28% Approval: 80.11%			
260	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.21% Approval: 69.84%			
261	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.48% Approval: 67.64%			
262	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 90.96% Approval: 80.08%	Support 3/16/12		
263	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 92.68% Approval: 94.61%	Support 3/16/12		
264	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.72% Approval: 87.34%			
265	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.94% Approval: 87.32%			
266	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1b	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 90.44% Approval: 93.23%			
267	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 76.84%	Abstain 4/19/12		
268	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 88.11%	Support 4/19/12		
269	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 80.79%	Support 4/19/12		
270	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.63% Approval: 37.37%	Abstain 5/17/12		
271	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.45% Approval: 60.55%	Abstain 5/17/12		
272	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.40% Approval: 38.81%	Abstain 5/17/12		
273	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.98% Approval: 55.08%	Abstain 5/17/12		
274	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.22% Approval: 38.50%	Abstain 5/17/12		
275	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 45.78%	Abstain 5/17/12		
276	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.19% Approval: 67.19%	Abstain 5/17/12		
277	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 60.19%	Abstain 5/17/12		
278	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 47.92%	Abstain 5/17/12		
279	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 58.23%	Abstain 5/17/12		
280	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	5/11/2012	5/21/2012	Quorum: 85.12% Approval: 66.23%	Abstain 5/17/12		
281	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	5/11/2012	5/21/2012	Quorum: 84.09% Approval: 47.88%	Abstain 5/17/12		
282	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	5/15/2012	5/24/2012	Quorum: 84.43% Approval: 46.18%			
283	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	5/15/2012	5/24/2012	Quorum: 79.95% Approval: 52.67%			
284	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Initial Ballot	6/11/2012	6/20/2012	Quorum: 84.14% Approval: 21.11%	Oppose 6/13/12		
285	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	6/11/2012	6/20/2012	Quorum: 81.01% Approval: 28.30%			
286	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	6/18/2012	6/27/2012	Quorum: 79.46% Approval: 79.00%			
287	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	6/18/2012	6/27/2012	Quorum: 75.00% Approval: 70.21%			
288	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Successive Ballot	6/18/2012	6/27/2012	Quorum: 85.98% Approval: 68.22%	Support 6/26/12		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
289	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Initial Ballot	6/26/2012	7/5/2012	Quorum: 84.24% Approval: 23.82%	Oppose 6/27/12		
290	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	6/26/2012	7/5/2012	Quorum: 82.26% Approval: 25.19%			
291	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.34% Approval: 81.71%			
292	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.04% Approval: 81.72%			
293	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 84.16% Approval: 79.16%			
294	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 83.87% Approval: 86.91%			
295	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	6/27/2012	7/9/2012	Quorum: 75.37% Approval: 72.16%	No Consensus 7/5/12		
296	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	6/27/2012	7/11/2012	Quorum: 75.37% Approval: 73.71%			
297	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Recirculation Ballot	7/18/2012	7/27/2012	Quorum: 90.97% Approval: 69.81%	Support 6/26/12		
298	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Non-binding Poll	7/18/2012	7/27/2012	Quorum: 81.31% Approval: 60.93%			
299	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Initial Ballot	7/20/2012	7/30/2012	Quorum: 80.39% Approval: 79.28%	Oppose 7/20/12		
300	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Non-binding Poll	7/20/2012	7/30/2012	Quorum: 78.26% Approval: 76.07%			
301	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Initial Ballot	7/24/2012	8/2/2012	Quorum: 83.11% Approval: 54.16%	Oppose 7/20/12		
302	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	8/17/2012	8/27/2012	Quorum: 78.11% Approval: 80.31%	Support 6/22/12		
303	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group	Successive Ballot	8/23/2012	9/4/2012	Quorum: 79.21% Approval: 87.78%	Support 2/22/10		
304	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Initial Ballot	8/29/2012	9/7/2012	Quorum: 86.71% Approval: 37.68%	Support 9/5/12		
305	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	8/29/2012	9/7/2012	Quorum: 84.17% Approval: 37.36%			
306	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Recirculation Ballot	9/6/2012	9/17/2012	Quorum: 80.35% Approval: 75.01%			
307	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols	Successive Ballot	9/11/2012	9/20/2012	Quorum: 77.70% Approval: 50.57%	Support 9/15/12		
308	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	9/11/2012	9/20/2012	Quorum: 84.05% Approval: 54.07%			
309	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Recirculation Ballot	9/12/2012	9/21/2012	Quorum: 85.36% Approval: 87.34%			
310	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	9/18/2012	9/27/2012	Quorum: 78.54% Approval: 63.40%	No Consensus 9/27/12		
311	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	9/18/2012	9/27/2012	Quorum: 78.93% Approval: 71.04%			
312	Project 2009-19	Project 2009-19 - Interpretation of BAL-002-0 NWPP Reserve Sharing Group	Recirculation Ballot	9/28/2012	10/8/2012	Quorum: 85.11% Approval: 90.34%	Support 2/22/10		
313	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 74.85%	Support 10/4/12		
314	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.37% Approval: 89.50%	Support 10/4/12		
315	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 85.58%	Support 10/4/12		
316	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 89.46%	Support 10/4/12		
317	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.11%	Support 10/4/12		
318	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 87.73%	Support 10/4/12		
319	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.74%	Support 10/4/12		
320	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.73%	Support 10/4/12		
321	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 84.60%	Support 10/4/12		
322	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.90%	Support 10/4/12		
323	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	10/1/2012	10/10/2012	Quorum: 78.93% Approval: 94.00%	Support 10/4/12		
324	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	10/1/2012	10/10/2012	Quorum: 79.13% Approval: 91.59%	Support 10/4/12		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
325	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Initial Ballot	10/3/2012	10/12/2012	Quorum: 87.50% Approval: 63.25%	Support 10/4/12		
326	VRFs and VSLs	Revisions to Outstanding VRFs and VSLs	Non-binding Poll	10/10/2012	10/23/2012	Quorum: 78.57% Approval: 73.02%			
327	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Recirculation Ballot	10/15/2012	10/24/2012	Quorum: 81.08% Approval: 80.51%	Support 6/22/12		
328	Project 2007-09	Project 2007-09_Generator Verification: MOD-026-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.55% Approval: 76.50%			
329	Project 2007-09	Project 2007-09_Generator Verification: PRC-024-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.00% Approval: 57.24%			
330	Project 2007-09	Project 2007-09_Generator Verification: MOD-025-2	Successive Ballot	10/19/2012	10/31/2012	Quorum: 83.61% Approval: 68.31%			
331	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.34% Approval: 71.53%			
332	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.07% Approval: 70.64%			
333	Project 2007-09	Project 2007-09_Generator Verification: MOD-026-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.88% Approval: 77.10%			
334	Project 2007-09	Project 2007-09_Generator Verification: PRC-024-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.40% Approval: 52.72%			
335	Project 2007-09	Project 2007-09_Generator Verification: MOD-025-2	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 77.94% Approval: 64.24%			
336	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.06% Approval: 68.93%			
337	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.51% Approval: 63.63%			
338	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 78.59%	Support 10/4/12		
339	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 92.75%	Support 10/4/12		
340	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 89.73%	Support 10/4/12		
341	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 93.73%	Support 10/4/12		
342	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.53%	Support 10/4/12		
343	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 91.79%	Support 10/4/12		
344	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.47%	Support 10/4/12		
345	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 94.60%	Support 10/4/12		
346	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 88.99%	Support 10/4/12		
347	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.67%	Support 10/4/12		
348	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation Plan	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 94.91%	Support 10/4/12		
349	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 93.23%	Support 10/4/12		
350	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Recirculation Ballot	10/24/2012	11/5/2012	Quorum: 85.14% Approval: 71.39%			
351	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	10/24/2012	11/5/2012	Quorum: 78.93% Approval: 71.04%			
352	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Successive Ballot	10/26/2012	11/6/2012	Quorum: 82.04% Approval: 76.08%	Support 11/5/12		
353	Project 2010-11	Project 2010-11 TPL footnote b Initial Ballot October 2012 in	Initial Ballot	11/9/2012	11/19/2012	Quorum: 80.45% Approval: 56.18%			
354	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Initial Ballot	11/26/2012	12/5/2012	Quorum: 84.81% Approval: 72.57%	Oppose 12/5/12		
355	Project 2013-02	Project 2013-02 - Paragraph 81	Initial Ballot	11/30/2012	12/10/2012	Quorum: 75.77% Approval: 96.45%	Support 12/10/12		
356	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	12/4/2012	12/13/2012	Quorum: 76.78% Approval: 53.57%	No Consensus 12/13/12		
357	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	12/4/2012	12/13/2012	Quorum: 77.22% Approval: 57.91%			
358	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Successive Ballot	12/7/2012	12/17/2012	Quorum: 76.47% Approval: 33.23%	Oppose 12/17/12		
359	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	12/7/2012	12/17/2012	Quorum: 75.58% Approval: 34.80%			
360	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Initial Ballot	12/11/2012	12/20/2012	Quorum: 84.50% Approval: 95.60%	Support 12/19/12		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
361	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	12/11/2012	12/20/2012	Quorum: 83.24% Approval: 84.48%	Support 12/19/12		
362	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 79.00% Approval: 79.36%			
364	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.68% Approval: 74.27%			
365	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 85.87% Approval: 73.63%			
366	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.19% Approval: 76.53%			
367	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	1/2/2013	1/11/2013	Quorum: 78.16% Approval: 60.31%	Support 1/11/13		
368	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	Non-binding Poll	1/2/2013	1/11/2013	Quorum: 76.38% Approval: 55.68%			
369	Project 2010-11	Project 2010-11 Successive Ballot December 2012 in	Successive Ballot	1/2/2013	1/11/2013	Quorum: 85.47% Approval: 65.77%	No Consensus 1/11/13		
370	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Initial Ballot	1/4/2013	1/14/2013	Quorum: 83.94% Approval: 21.80%	Oppose 1/11/13		
371	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Non-binding Poll	1/4/2013	1/14/2013	Quorum: 82.23% Approval: 24.27%			
372	Project 2013-02	Project 2013-02 - Paragraph 81	Recirculation Ballot	1/8/2013	1/17/2013	Quorum: 84.60% Approval: 95.22%	Support 12/10/12		
373	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Recirculation Ballot	1/14/2013	1/23/2013	Quorum: 87.13% Approval: 99.09%	Support 12/19/12		
374	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Recirculation Ballot	1/18/2013	1/28/2013	Quorum: 85.90% Approval: 85.57%	Support 12/19/12		
375	Project 2010-11	Project 2010-11 Recirculation Ballot Jan 2013 in	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 88.55% Approval: 69.63%	No Consensus 1/11/13		
376	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 85.67% Approval: 77.61%	Oppose 12/5/12		
377	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Successive Ballot	2/11/2013	2/20/2013	Quorum: 77.62% Approval: 50.66%	Support 9/5/12		
378	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	2/11/2013	2/20/2013	Quorum: 75.38% Approval: 50.60%			
379	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	2/15/2013	2/28/2013	Quorum: 78.80% Approval: 89.01%	Support 1/11/13		
380	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Non-binding Poll	2/15/2013	2/28/2013	Quorum: 76.38% Approval: 84.24%			
381	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Initial Ballot	3/1/2013	3/11/2013	Quorum: 76.36% Approval: 54.65%			
382	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Successive Ballot	3/13/2013	3/22/2013	Quorum: 77.48% Approval: 84.27%	No Consensus 3/22/13		NPCC to abstain - international nature of the ERO and BPS is not used in Reliability Standards
383	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.58% Approval: 97.18%	Support 3/14/13		
384	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.52% Approval: 98.89%	Support 3/14/13		
385	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Recirculation Ballot	3/18/2013	3/27/2013	Quorum: 81.33% Approval: 89.44%	Support 1/11/13		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
386	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	3/27/2013	4/5/2013	Quorum: 78.39% Approval: 57.50%	No Consensus 4/4/13		The RSC did not reach a full consensus however the majority of respondents had indicated they will support the standard - see comment form for further details. Some believe the standard is not necessary and that existing whitepapers alleviate the need for it. In recognition of the NERC BOT's expectations that COM-003 will be approved by the industry and brought before them for approval, NPCC has voted affirmatively and will supply comments for the record outlining our concerns.
387	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	3/27/2013	4/5/2013	Quorum: 77.97% Approval: 54.28%			
388	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.60% Approval: 66.98%	No Consensus 4/23/13		The majority of NPCC's Balancing Authorities have indicated support for the standard, however NPCC as the Regional Entity has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. To be respectful of the positions of the NPCC BAs who will have to implement this new methodology and the support expressed, NPCC as the Regional Entity will cast an Abstention
389	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 42.75%	Oppose 4/23/13		There is a lack of technical justification for the 500 MW threshold within the standard-NPCC will submit suggested improvements
390	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 23.84%	Oppose 4/23/13		Losses of large blocks of load are typically caused by coincident transmission contingencies. Excessive and uninformed adjustments made to generation in order to bring the ACE to zero may well lead to further transmission issues. NPCC will submit suggested improvements
391	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
392	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
393	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
394	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Recirculation Ballot	4/18/2013	4/29/2013	Quorum: 80.70% Approval: 88.15%	No Consensus 3/22/13		
395	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Successive ballot	5/15/2013	5/24/2013	Quorum: 81.25% Approval: 69.23%	Support 5/23/13		The Regional Standard Committee has not expressed any concerns of significance that would warrant a ballot to reject, therefore the RSC recommends a yes vote, "Affirmative", to accept the standard
396	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Non-binding Poll	5/15/2013	5/24/2013	Quorum: 80.17% Approval: 61.11%			
397	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Successive Ballot	6/24/2013	7/3/2013	Quorum: 77.65% Approval: 52.71%			
398	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Non-binding Poll	6/24/2013	7/3/2013	Quorum: 77.12% Approval: 52.48%			
399	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Initial Ballot	7/3/2013	7/12/2013	Quorum: 85.53% Approval: 49.73%			
400	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Successive Ballot	7/10/2013	7/19/2013	Quorum: 76.32% Approval: 58.36%	No Consensus 7/19/13 [Due to the concerns expressed over the potential actions by the NERC BOT and FERC as well as the incremental improvement of the standard over the previous versions, NPCC as the Regional Entity will support the standard and submit comments.]		[illegible] organizations support the standard as written however some members expressed concern that in order to measure compliance with R1 and R2, the standard will require all Reliability Directives to be investigated to determine if RC approved and documented communication protocols have been violated. Also it was identified that TO, BA communication protocols would have to approved by the RC potentially causing some legal issues if protocols aren't approved and casts question on the enforcement of those protocols. NPCC will be submitting some helpful comments should the standard pass and some non-substantive revision be performed prior to the "final" (previously named recirculation) ballot.
401	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 76.20% Approval: 55.37%			
402	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Successive Ballot	7/10/2013	7/19/2013	Quorum: 85.05% Approval: 72.43%	Support 7/19/13		
403	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 82.51% Approval: 64.59%			
404	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Final Ballot	7/16/2013	7/25/2013	Quorum: 92.31% Approval: 74.54%	No Consensus 7/22/13		The RSC has not reached a full consensus however the majority are in support. Issues outstanding for those not in support are concern over "hitting limits" more frequently and potential issues with BA's potentially "dragging" on the interconnection. NPCC will be voting affirmative on the standard.

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
405	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Initial Ballot	7/26/2013	8/5/2013	Quorum: 80.05% Approval: 93.00%	Support 8/5/13		
408	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025-1	Final Ballot	8/2/2013	8/12/2013	Quorum: 89.13% Approval: 76.52%	Support 8/12/13		
406	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Initial Ballot	8/2/2013	8/12/2013	Quorum: 76.32% Approval: 62.74%	Support 8/9/13		
407	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	8/2/2013	8/12/2013	Quorum: 75.89% Approval: 55.45%			
409	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Initial Ballot	8/14/2013	8/23/2013	Quorum: 78.33% Approval: 79.42%	Support 8/23/13		
410	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Non-binding Poll	8/14/2013	8/23/2013	Quorum: 77.45% Approval: 81.37%			
411	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Ballot	8/16/2013	8/26/2013	Quorum: 76.14% Approval: 51.10%	No Consensus 8/26/13		NPCC to support with comments
412	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Non-binding Poll	8/16/2013	8/26/2013	Quorum: 75.98% Approval: 53.29%			
413	Project 2010-01	Project 2010-01 - Training - PER-005-2	Ballot	8/23/2013	9/3/2013	Quorum: 75.25% Approval: 34.46%	No Consensus 8/31/13		NPCC to support with comments The most contentious issues raised by RSC members was surrounding the Control Center definition and the potential to vastly expand those needing training subject to the standard and compliance and that there was no need for a standard, rather, the FERC Directives should be addressed through other means.
414	Project 2010-01	Project 2010-01 - Training - PER-005-2	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 80.45% Approval: 34.24%			
415	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Ballot	8/23/2013	9/3/2013	Quorum: 81.89% Approval: 43.79%	Oppose 8/31/13		The standard, in the view of the group, has extensive issues including but not limited to, applicability issues, lacks clarity, missing measures, quality, and other substantive issues. NPCC will be submitting detailed comments to address these issues. The RSC does not believe it would be beneficial to support the standard at this point as the next step, if it fails the initial ballot, would still require an additional ballot prior to moving to recirculation due to the substantive changes that are needed for the next revision. NPCC will be submitting helpful comments to NERC and supporting the drafting team effort.
416	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 79.95% Approval: 44.23%			
417	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Ballot	8/26/2013	9/4/2013	Quorum: 82.29% Approval: 41.24%	Support 8/31/13		
418	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 79.66% Approval: 40.00%			
419	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Ballot	8/26/2013	9/4/2013	Quorum: 81.96% Approval: 55.76%	Support 8/31/13		
420	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 80.35% Approval: 58.97%			

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421	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	8/26/2013	9/4/2013	Quorum: 78.68% Approval: 66.11%	Support 8/31/13		
426	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Final Ballot	9/4/2013	9/13/2013	Quorum: 85.93% Approval: 90.83%	Support 8/5/13		
422	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Ballot	9/6/2013	9/16/2013	Quorum: 76.15% Approval: 58.23%	No Consensus 9/12/13		
423	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Non-binding Poll	9/6/2013	9/16/2013	Quorum: 75.69% Approval: 59.66%			
424	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Final Ballot	9/11/2013	9/20/2013	Quorum: 91.64% Approval: 98.61%	Support 3/14/13		
425	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Final Ballot	9/11/2013	9/20/2013	Quorum: 90.98% Approval: 98.92%	Support 3/14/13		
427	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Additional Ballot	10/9/2013	10/21/2013	Quorum: 77.58% Approval: 88.75%	Support 10/16/13		
428	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	10/9/2013	10/21/2013	Quorum: 75.89% Approval: 90.04%			
429	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Final Ballot	10/16/2013	10/25/2013	Quorum: 85.71% Approval: 85.38%			
430	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	10/18/2013	10/29/2013	Quorum: 75.83% Approval: 72.55%	Support 10/21/13		
431	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Final Ballot	10/25/2013	11/4/2013	Quorum: 86.90% Approval: 91.95%			
432	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	10/25/2013	11/7/2013	Quorum: 76.67% Approval: 58.24%	No Consensus 11/1/13		
433	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	11/1/2013	11/12/2013	Quorum: 76.23% Approval: 56.48%	Support 11/11/13		
434	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Initial Ballot	11/4/2013	11/13/2013	Quorum: 76.12% Approval: 67.35%	Support 11/5/13		
435	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-006-4	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 75.58%	Support 11/5/13		
436	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-009-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 68.40%	Support 11/5/13		
437	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 58.03%	Support 11/5/13		
438	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-011-1	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.52% Approval: 71.35%	Support 11/5/13		
439	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Initial Ballot	11/4/2013	11/15/2013	Quorum: 76.42% Approval: 77.82%	Support 11/5/13		
440	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Final Ballot	11/8/2013	11/18/2013	Quorum: 81.68% Approval: 74.34%	Support 10/21/13		
441	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Additional Ballot	11/8/2013	11/20/2013	Quorum: 81.69% Approval: 82.97%	No Consensus 8/26/13		
442	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.05% Approval: 73.46%	Support 8/31/13		
443	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.84% Approval: 69.42%	Support 8/31/13		
444	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	11/13/2013	11/22/2013	Quorum: 80.54% Approval: 57.59%	Support 8/31/13		
445	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Additional Ballot	11/15/2013	11/25/2013	Quorum: 80.81% Approval: 69.43%			
446	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	11/15/2013	11/25/2013	Quorum: 81.06% Approval: 66.09%			
447	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2	Additional Ballot	12/2/2013	12/12/2013	Quorum: 75.29% Approval: 64.24%	No Consensus 12/9/13	Affirmative	

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
448	Project 2007-11	Project 2007-11 Disturbance Monitoring - PRC-002-2	Initial Ballot	12/6/2013	12/16/2013	Quorum: 82.25% Approval: 43.29%	No Consensus 12/15/13	Affirmative	Highlights of comments received expressed: • Agreement with the methodology to determine BES locations for which data had to be captured • Use of the term "locations" • DDR for Flowgates, IROLs • Clarification needed for some data that is to be captured • Editorial suggestions
449	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Final Ballot	12/6/2013	12/16/2013	Quorum: 87.53% Approval: 77.49%	Support 8/31/13	Affirmative	
450	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-006-4	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 80.77%	Support 11/5/13	Affirmative	
451	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-009-2	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 72.86%	Support 11/5/13	Affirmative	
452	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-011-1	Final Ballot	12/10/2013	12/20/2013	Quorum: 84.78% Approval: 72.91%	Support 11/5/13	Affirmative	
453	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Final Ballot	12/11/2013	12/20/2013	Quorum: 87.16% Approval: 86.40%	No Consensus 8/26/13	Affirmative	
454	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Final Ballot	12/13/2013	12/23/2013	Quorum: 84.34% Approval: 75.35%		Affirmative	
455	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-027-1	Additional Ballot	12/9/2013	12/31/2013	Quorum: 76.60% Approval: 65.71%	No Consensus 12/27/13	Affirmative	
456	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	1/10/2014	1/21/2014	Quorum: 76.92% Approval: 81.41%	Support 8/31/13	Affirmative	
457	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	1/8/2014	1/22/2014	Quorum: 7912% Approval: 74.63%	Support 11/11/13	Affirmative	
458	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 81.19%	Support 11/5/13	Affirmative	
459	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 90.23%	Support 11/5/13	Affirmative	
460	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Additional Ballot	1/16/2014	1/29/2014	Quorum: 76.12% Approval: 92.17%	Support 11/5/13	Affirmative	
461	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	1/22/2014	1/31/2014	Quorum: 76.03% Approval: 71.86%	No Consensus 11/1/13	Affirmative	Ballot Period Extended to 2/4/14
462	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.88% Approval: 83.44%	Support 11/5/13	Affirmative	
463	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.58% Approval: 91.51%	Support 11/5/13	Affirmative	
464	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Final Ballot	1/27/2014	2/5/2014	Quorum: 82.49% Approval: 82.45%	Support 8/31/13	Affirmative	
465	Project 2010-01	Project 2010-01 - Training - PER-005-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 84.02% Approval: 77.06%	Support 11/11/13	Affirmative	
466	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Final Ballot	1/31/2014	2/10/2014	Quorum: 81.79% Approval: 90.12%	Support 11/5/13	Affirmative	
467	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Additional Ballot	2/21/2014	3/3/2014	Quorum: 75.06% Approval: 62.63%	Support 9/5/12	Affirmative	Ballot Period Extended to 3/11/14
468	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Final Ballot	3/28/2014	4/7/2014	Quorum: 78.21% Approval: 77.62%	Support 3/28/14	Affirmative	
469	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	4/1/2014	4/10/2014	Quorum: 76.92% Approval: 83.40%	Support 8/31/13	Affirmative	
470	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	4/4/2014	4/14/2014	Quorum: 78.03% Approval: 82.40%		--	
471	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	Initial Ballot	4/20/2014	4/24/2014	Quorum: 88.60% Approval: 82.07%	Support 4/23/14	Abstain	
472	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Final Ballot	4/25/2014	5/5/2014	Quorum: 80.37% Approval: 90.00%	Support--4/25/14	Affirmative	
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	

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	
476	Project 2012-13	Project 2012-13 - NUC - Nuclear Plant Interface Coordination	Initial Ballot	5/13/2014	5/22/2014	Quorum: 80.60% Approval: 97.36%	Support--5/20/14	Affirmative		
477	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) - PRC-005-X	Initial Ballot	5/23/2014	6/2/2014	Quorum: 85.42% Approval: 47.89%	Support	Affirmative		
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Initial Ballot	5/30/2014	6/9/2014	Quorum: 79.06% Approval: 17.02%	Does not Support--6/6/14	Negative		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Final Ballot	6/12/2014	6/23/2014	Quorum: Approval: 89.03%/83.46%	Support	Affirmative		
479	Project 2007-11	Project 2007-11 - Disturbance Monitoring - PRC-002-2	Additional Ballot	6/13/2014	6/23/2014	Quorum: 77.69% Approval: 52.29%	Support	Affirmative	Extended to achieve a quorum.	
480	Project 2010-05.1	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Additional Ballot	6/20/2014	7/9/2014	Quorum: 76.98% Approval: 74.53%	Support	Affirmative	Extended to achieve a quorum.	Last RSC Meeting
481	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Ballot	6/23/2014	7/2/2014	Quorum: 82.32%/82.59%/82.59%/82.85%/82.85%/82.06%/82.59%/82.85%/82.85%/81.00%/80.74% Approval: 68.57%/36.94%/47.87%/60.26%/61.67%/57.94%/30.99%/62.18%/63.07%/62.64%/64.70%	No Consensus--6/24/14	Affirmative Negative Affirmative Affirmative Affirmative Affirmative Negative Affirmative Affirmative		
482	Project 2012-13	Project 2012-13 NUC - Nuclear Plant Interface Coordination	Final Ballot	6/24/2014	7/3/2014	Quorum: 88.63% Approval: 97.23%	Support--6/23/14	Affirmative		
483	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions Rich HTML Content 1 http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/16/2014	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29% Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 Yes CIP-010 Yes CIP-011 Yes Definitions Yes Support--7/14/14			
484	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Final Ballot	7/16/2014	7/25/2014	Quorum: 78.92% Approval: 58.88%	Support--7/23/14			
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.49%/80.15%/80.00%/80.83%/80.36% Approval: 91.38%/92.20%/89.51%/90.58%/87.09%	Support--7/24/14	Affirmative		
486	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 82.67% Approval: 55.77%		Affirmative		
487	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Initial Ballot	7/29/2014	8/7/2014	Quorum: 76.37% Approval: 76.91%		Affirmative		
488	Project 2012-13	Project 2009-03 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.66% Approval: 42.27%	Negative--8/14/14	Negative		
489	Project 2014-01	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.94% Approval: 79.75%	Support	Affirmative		
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 85.32%/86.01% Approval: 95.35%/95.86%	Support	Affirmative		
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3	Additional Ballot	9/3/2014	9/12/2014	Quorum: 84.33% Approval: 76.03%	Support--9/4/14	Affirmative		
492	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Additional Ballot	9/10/2014	9/19/2014	Quorum: 85.75%/84.96%/84.96%/85.22%/84.96%/85.22%/85.49%/85.22%/86.28%/83.11%/83.91%	TOP-001-3: Negative TOP-002-4: Affirmative TOP-003-3: Affirmative IRO-001-4: No consensus however the majority indicated an Affirmative vote IRO-002-4: Negative			

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						Approval: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%	IRO-008-2: No consensus, a majority indicated a Negative and the others indicated abstention IRO-010-2: Affirmative IRO-014-3: Negative IRO-017-1: Affirmative Implementation Plan and Definitions: Affirmative 9/18/14		
493	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	9/23/2014	10/2/2014	Quorum: 79.94% Approval: 46.73%	Negative--10/1/14		
494	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	9/26/2014	10/6/2014	Quorum: 79.01% Approval: 53.02%	Affirmative--10/1/14		
495	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Additional Ballot	9/29/2014	10/8/2014	Quorum: 83.24%/84.82% Approval: 80.69%/84.05%	Affirmative--10/7/14	Affirmative	
496	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	10/1/2014	10/10/2014	Quorum: 82.93% Approval: 57.95%	Affirmative--10/7/14		
497	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Additional Ballot	10/3/2014	10/14/2014	Quorum: 80.54% Approval: 75.79%	Affirmative--10/7/14		
498	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/7/2014	10/16/2014	Quorum: 81.91%/82.12% Approval: 94.92%/94.37%	Affirmative--10/14/14		
499	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Additional Ballot	10/8/2014	10/17/2014	Quorum: 84.63%/84.15%/84.15%/83.90%/83.41%/83.66%/83.96%/84.49%/83.96%/83.96%/84.22 Approval: 93.21%/68.09%/74.25%/79.91%/85.68%/89.01%/91.79%/81.34%/96.63%/96.63%/95.52%/85.93%/98.13%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative	CIP-003-6 and CIP-010-2 Affirmative	
500	Project 2009-03	Project 2009-03 Emergency Operations	Additional Ballot	10/10/2014	10/20/2014	Quorum: 80.93% Approval: 70.41%	Affirmative--10/17/14		
501	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (IRO-001-4, IRO-002-4, IRO-010-2, two Definitions, and Implementation Plan)	Final Ballot	10/10/2014	10/20/2014	Quorum: 90/77%/89.97%/89.97%/88.39%/88.39% Approval: 82.64%/85.96%/86.22%/94.07%/91.84%	Affirmative--10/17/14		
502	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3, and IRO-017-1)	Final Ballot	10/10/2014	10/20/2014	Quorum: 89.71%/88.39%/89.71%/89.71%/89.97% 84.76%/86.55%/83.73%/89.88%/82.58%	Affirmative--10/17/14		
503	Project 2007-11	Project 2007-11 Disturbance Monitoring	Additional Ballot	10/10/2014	10/21/2014	Quorum: 77..69% Approval: 71.38%	Affirmative--10/17/14		
504	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/10/2014	10/22/2014	Quorum: 85.13%/83.29% Approval: 94.75%/93.98%	Affirmative--10/20/14		
505	Project 2014-03	Project 2007-17.3 (PRC-005-X) Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays)	Final Ballot	10/20/2014	10/29/2014	Quorum: 88.25% Approval: 74.14%	Affirmative--10/28/14		
506	Project 2014-03	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.53% Approval: 83.12%	Affirmative--10/31/14		
507	Project 2007-11	Project 2007-11 Disturbance Monitoring	Final Ballot	10/28/2014	11/6/2014	Quorum: 81.89% Approval: 68.51%	Affirmative--10/31/14		
508	Project 2007-11	Project 2010-05.2 Phase 2 of Special Protection Systems	Final Ballot	10/28/2014	11/6/2014	Quorum: 85.41% Approval: 73.33%	Negative--10/14/14		
509	Project 2007-11	Project 2009-03 Emergency Operations	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.19% Approval: 73.20%	Affirmative--10/17/14		

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510	Project 2007-11	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	10/28/2014	11/6/2014	Quorum: 89.49%/87.66%/87.08 % Approval: 92.91%/92.15%/95.62 %	Affirmative--10/20/14		
511	Project 2014-03	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.56%/87.32%87.07 %/87.56%/87.80%87. 56%86.59% Approval: 83.84%/95.34%/86.00 %/95.35%91.17%/83. 88%/95.40%/92.76%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative		
512	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	11/4/2014	11/10/2014	Quorum: 78.36% Approval: 60.21%	Affirmative--11/4/14		
513	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	11/12/2014	11/21/2014	Quorum: 79.73% Approval: 77.29%	Affirmative--11/21/14		
514	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	11/14/2014	11/24/2014	Quorum: 79.83% Approval: 67.39%	Affirmative--10/1/14		
515	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.27% Approval: 78.05%	Affirmative--12/12/14		
516	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.81% Approval: 68.08%	Affirmative--12/15/14		
517	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Initial Ballots	12/10/2014	12/23/2014	Quorum: 79.38%/79.72%/79.60 % Approval: 92.69%/93.55%/93.67 %	Affirmative--12/22/14		
518	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	12/19/2014	1/7/2015	Quorum: 80.47% Approval: 72.43%	Affirmative--1/6/15		
519	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions	Additional Ballot	12/30/2014	1/9/2015	Quorum: 81.22%/81.71%/81.46 %/81.71%/81.71%/81. 22%/81.71%/81.46% Approval: 81.92%/98.89%/98.86 %/88.13%/98.89%/86. 02%/89.63%/97.21%	CIP-003-7 Binding and non-binding polls-no consensus CIP-003-7 Definition-Affirmative CIP-010-7 Binding and non-binding polls- Affirmative CIP-010-7 Definition- Affirmative CIP-004-7 Binding and non-binding polls – Affirmative CIP-007-7 Binding and non-binding polls –Affirmative CIP-011-7 Binding and non-binding polls –Affirmative CIP Implementation Plan- Affirmative 1/8/2015		
520	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards - TOP-001-3	Final Ballots	1/15/2015	1/21/2015	Quorum: 84.70% Approval: 72.69%	Affirmative--1/6/15		
521	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Initial Ballots	1/12/2015	1/22/2015	Quorum: 77.93% Approval: 93.74%	Affirmative--1/22/15		
522	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-001-1.1(ii), PRC-019-2, and PRC-024-2	Final Ballots	1/13/2015	1/22/2015	Quorum: 89.27%/89.30%/89.52 % Approval: 93.99%/94.03%/95.82 %	Affirmative--1/22/15		
523	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions CIP-003-7, CIP-004-7, CIP-010-3, and CIP-011-3	Final Ballot	1/23/2015	2/2/2015	Quorum: 84.15%/84.39%/84.15 %/84.39%/84.39%/83. 90%/84.39%/83.66% Approval: 79.76%/98.94%/98.94 %/86.76%/98.93%/84. 07%/90.10%/97.32%	Affirmative--1/29/15		
524	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Final Ballot	3/2/2015	3/11/2015	Quorum: 83.52% Approval: 98.03%	Affirmative--1/22/15		
525	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	3/6/2015	3/16/2015	Quorum: 77.29% Approval: 59.30%	Negative--3/13/2015		
526	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Initial Ballot	3/27/2015	4/7/2015	Quorum: 79.93% Approval: 84.31%	Affirmative--3/31/15		

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527	Project 2014-04	Project 2014-04 Physical Security	Initial Ballot	3/31/2015	4/9/2015	Quorum: 88.33% Approval: 89.95%	Affirmative--3/31/15		
528	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Final Ballot	4/17/2015	4/27/2015	Quorum: 84.86% Approval: 89.63%	Affirmative--3/31/15		
529	Project 2014-04	Project 2014-04 Physical Security	Final Ballot	4/20/2015	4/29/2015	Quorum: 92.00% Approval: 92.35%	Affirmative--3/31/15		
530	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	5/6/2015	5/15/2015	Quorum: 81.79% Approval: 39.63%	Negative--5//13/15		
531	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Initial Ballot	6/29/2015	7/8/2015	Quorum: 75.23%/84.00% Approval: 90.35%/97.50%	Affirmative--7/7/15		
532	Project 2015-04	2015-04 Alignment of Terms	Initial Ballot	7/17/2015	7/27/2015	Quorum: 90.43%/91.17%/91.10%/91.01%/91.10%/91.17%/91.17%/91.34%/90.97%/91.40%/90.10%/91.01%/91.07%/91.07%/91.07%/91.34%/91.43%/90.75%/91.34%/91.01%/91.40%/91.01%/91.01%/91.01%/91.01%/91.01% Approval: 91.46%/88.57%/86.68%/97.06%/97.10%/81.06%/80.73%/96.38%/97.03%/69.80%/95.38%/93.62%/96.83%/97.00%/98.55%/87.37%/89.99%/84.38%/88.06%/90.37%/97.75%/91.28%/87.71%/89.44%/87.15%/98.24%	Affirmative--7/24/15		
533	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Final Ballots	7/22/2015	7/31/2015	Quorum: 85.98%/90.67%% Approval: 88.23%/96.84%	Affirmative--7/7/15		
534	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	8/11/2015	8/20/2015	Quorum: 75.92% Approval: 69.26%	Affirmative--8/17/15		
535	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	9/2/2015	9/11/2015	Quorum: 84.34% Approval: 69.76%	Affirmative--9/8/15		
536	Project 2007-06	Project 2007-06.2 Phase 2 of System Protection Coordination	Initial Ballot	9/2/2015	9/11/2015	Quorum: 87.16% Approval: 62.55%	Affirmative--9/11/15		
537	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Initial Ballot	9/4/2015	9/14/2015	Quorum: 83.81% Approval: 55.97%	Abstention--9/14/15		
538	Project 2015-04	2015-04 Alignment of Terms	Final Ballot	9/4/2015	9/14/2015	Quorum: 96.81%/97.53%/97.51%/97.48%/97.51%/97.53%/97.53%/97.11%/97.11%/97.85%/96.80%/97.12%/97.14%/97.14%/97.14%/97.11%/97.14%/96.80%/97.11%/97.48%/97.85%/97.48%/97.48%/97.48%/97.48%/97.48%	Affirmative--7/24/15		

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						Approval: 93.13%/92.89%/91.33%/98.07%/98.07%/84.78%/84.75%/98.30%/98.06%/75.63%/95.46%/94.48%/98.31%/97.11%/98.57%/90.80%/95.60%/90.46%/92.07%/92.49%/97.81%/92.84%/91.09%/91.32%/90.80%/98.29%	Affirmative--7/24/15		
539	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	Initial Ballot	9/4/2015	9/16/2015	Quorum: 86.97% Approval: 96.73%	Affirmative--9/16/15		
540	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	Initial Ballot	9/9/2015	9/18/2015	Quorum: 85.57% Approval: 87.36%	Affirmative--9/18/15		
541	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Initial Ballot	9/25/2015	10/5/2015	Quorum: 83.70% Approval: 48.10%	N egative--10/2/15		
542	Project 2010-05.3	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Final Ballot	9/29/2015	10/8/2015	Quorum: 84.28% Approval: 74.61%	Affirmative--8/17/15		
543	Project 2010-05.3	Project 2007-06 System Protection Coordination	Final Ballot	10/5/2015	10/14/2015	Quorum: 89.16% Approval: 80.94%	Affirmative--9/8/15		
544	Project 2010-05.3	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	Final Ballot	10/6/2015	10/15/2015	Quorum: 89.60% Approval: 90.01%	Affirmative--9/18/15		
545	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	Final Ballot	10/15/2015	10/26/2015	Quorum: 90.00% Approval: 96.38%	Affirmative--9/16/15		
546	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Initial Ballot	10/30/2015	11/9/2015	Quorum: 84.59%/84.49% Approval: 47.38%/48.00%	Abstention--11/5/15		
547	Project 2010-05.3	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Initial Ballot	11/3/2015	11/12/2015	Quorum: 84.40% Approval: 98.17%	Affirmative--11/5/15		
548	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Initial Ballot	11/6/2015	11/16/2015	Quorum: 88.18% Approval: 53.60%	Affirmative--11/13/15		
549	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Additional Ballot	11/10/2015	11/19/2015	Quorum: 83.18% Approval: 57.29%	Affirmative--11/18/15		
550	Project 2010-07.1	Project 2010-07.1 Vegetation Management	Initial Ballot	12/7/2015	12/16/2015	Quorum: 85.38% Approval: 82.56%	Negative--12/8/15		
547	Project 2010-05.3	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Final Ballot	12/8/2015	12/17/2015	Quorum: 88.65% Approval: 98.26%	Affirmative--11/5/15		
551	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	12/30/2015	1/8/2016	Quorum: 83.39%/80.88% Approval: 60.39%/92.94%	Affirmative--12/3015		
552	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Additional Ballot	12/31/2015	1/11/2016	Quorum: 84.13%/83.17%/84.44% Approval: 70.64%/75.54%/94.30%	BAL-005-1--Negative--1/10/16 BAL-006--Affirmative--1/10/16 FAC-003-1--Abstention--1/10/16		
553	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Additional Ballot	1/15/2016	1/25/2016	Quorum: 82.88%/82.18% Approval: 72.13%/68.01%	Affirmative--1/25/16		
554	Project 2010-07.1	Project 2010-07.1 Vegetation Management	Final Ballot	1/29/2016	2/8/2016	Quorum:90.03% Approval: 96.18%	Affirmative--2/1/16		
552	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Final Ballot	1/29/2016	2/8/2016	Quorum: 86.35%/86.98%/86.67% Approval: 72.06%/94.61%/80.15%	Affirmative--2/3/15		
551	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Final Ballot	2/17/2016	2/26/2016	Quorum: 88.36%/87.79% Approval: 75.68%/73.87%	Affirmative--1/25/16		
552	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	3/9/2016	3/18/2016	Quorum: 75.55%	Affirmative--3/10/16		

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: 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		

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Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments

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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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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
68.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 (Version 5 CIP Standards)	Version 5 CIP Standards		11/7/11	1/6/12	Yes 1/6/12
69.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2	TOP-001-2 TOP-002-3 TOP-003-2		12/14/11	1/12/12	Yes 1/12/12
70.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition, Phase 2		1/4/12	2/3/12	Yes 2/3/12
71.	N/A	Order 754 - Request for Data or Information	Data Request		12/22/11	2/6/12	Yes 2/6/12
72.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001 COM-002 IRO-001-3		1/9/12	2/9/12	Yes 2/8/12
73.	WECC Regional Standard	Regional Reliability Standard BAL-004-WECC-02 - Automatic Time Error Correction	BAL-004-WECC-02		1/23/12	3/9/12	
74.	WECC Regional Standard	Regional Reliability Standard BAL-001-0.1a - Real Power Balancing Control Performance - WECC Variance	BAL-001-0.1a		1/23/12	3/9/12	
75.	N/A	NERC Functional Model Demand Response Functions and Entities	NERC Functional Model		2/13/12	3/14/12	
76.	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 for WECC	Interpretation of CIP-004-1		2/8/12	3/23/12	Yes 3/23/12
77.	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Interpretation of CIP-002-1, R3		2/8/12	3/23/12	Yes 3/23/12

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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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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
213	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	04/17/14	05/05/14	Yes 5/5/14
214	Project 2010-02	Project 2010-02 – Connecting New Facilities to the Grid	FAC-001-1 FAC-002-1	Formal	04/01/14	05/15/14	Yes 5/15/14
215	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Informal	04/22/14	05/21/14	Yes 5/21/14
216	Project 2012-13	Project 2012-13 Nuclear Plant Interface Coordination	NUC-001-3	Formal	04/08/14	05/22/14	Yes 5/22/14
217	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays)	PRC-005-X	Formal	04/17/14	06/03/14	Yes 6/3/14
218	Project 2010-13.3	Project 2010-13.3 Relay Loadability: Stable Power Swings	PRC-026-1	Formal	04/25/14	06/09/14	Yes 6/9/14
219	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	05/09/14	06/25/14	Yes 6/25/14
221	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Informal	05/23/14	06/23/14	Yes 6/23/14
222	Project 2010-05-1	Project 2010-05-1 Protection System – Phase 1 – Misoperations	PRC-004	Formal	05/16/14	07/09/14	Yes 7/9/14
223	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	05/19/14	07/02/14	Yes 7/2/14
224	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-002 to CIP-011	Formal	06/02/14	07/17/14	Yes 7/16/14

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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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	2015-08	Operations					
318	Project 2015-INT-01	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	CIP-002-5.1	Formal	7/27/16	9/12/16	Yes 9/12/16
319	Project 2016-01	Modifications to TOP and IRO Standards SAR	TOP-001-3 IRO-002-4	Formal	8/31/16	10/17/16	Yes 10/14/16
320	Project 2016-04	Modifications to PRC-025-1 SAR	PRC-025-1	Formal	9/16/16	10/18/16	Yes 10/18/16
321	Project 2016-03	Cyber Security Supply Chain Management	SAR	Informal	10/20/16	11/18/16	Yes 11/18/16
322	Project 2016-02	Modifications of CIP Standards	CIP-003-TCA	Informal	11/1/16	11/18/16	Yes 11/18/16
323	Project 2016-02	Modifications of CIP Standards	CIP-003-7	Formal	11/23/16	12/5/16	Yes 12/5/16
324	Project 2015-08	Emergency Operations	EOP-005-3 EOP-006-3	Formal	10/26/16	12/9/16	Yes 12/9/16
325	Project 2015-08	Emergency Operations	EOP-004-4	Formal	11/18/16	1/6/17	Yes 1/6/17
326	Project 2013-03	Geomagnetic Disturbance Mitigation	SAR	Informal	12/16/16	1/20/17	Yes 1/20/17
327	Project 2016-02	Modifications of CIP Standards	CIP-003-7(i)	Formal	12/12/16	1/25/17	Yes 1/25/17
328	Project 2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training and Qualifications Standard (PER)	PER-001-0.2 PER-003-1 PER-004-2	Formal	1/10/17	2/23/17	Yes 2/23/17
329	Project 2016-03	Cyber Security Supply Chain Risk Management	CIP-013-1	Formal	1/19/17	3/6/17	Yes 3/6/17
330	Project 2016-04	Modifications to PRC-025-1	SAR	Informal	3/20/17	4/3/17	Yes 4/3/17
331	Project 2016-02	Modifications to CIP Standard	Virtualization	Informal	3/14/17	4/11/17	Yes 4/11/17
332	Project 2016-02	Modifications to CIP Standard	TOCC	Informal	3/14/17	4/11/17	Yes 4/11/17
333	Project 2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive (VAR) Standards	VAR-001-4.1	Formal	2/28/17	4/13/17	Yes 4/13/17
334	Project 2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive (VAR) Standards	VAR-002-4	Formal	2/28/17	4/13/17	Yes 4/13/17
335	SPM	Revisions to the NERC Standard	SPM	Formal	3/20/17	5/3/17	Yes 5/3/17

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		Processes Manual					
336	Project 2015-10	Single Points of Failure	TPL-001-5	Informal	4/25/17	5/24/17	Yes 5/24/17
337	Project 2016-03	Cyber Security Supply Chain Risk Management	CIP-005-6 CIP-010-3 CIP-013-1	Formal	5/2/17	6/15/17	Yes 6/15/17
338	Project 2017-01	Modifications to BAL-003-1.1 SAR	BAL-003-1.1	Formal	6/19/17	7/18/17	Yes 7/18/17
339	Project 2017-06	Modifications to BAL-002-2 SAR	BAL-002-2	Informal	6/20/17	7/20/17	Yes 7/20/17
340	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications Standards	PER-003-1 PER-004-2	Informal	6/21/17	7/24/17	Yes 7/24/17
341	2018-2010	Reliability Standards Development Plan		Formal	6/22/17	7/25/17	Yes 7/26/17
342	Standards Grading	Periodic Review Standing Review Team	Standards Grading	Informal	6/19/17	8/2/17	Yes 8/2/17
343	Project 2013-03	Geomagnetic Disturbance Mitigation	TPL-007-2	Formal	6/28/17	8/11/17	Yes 8/11/17
344	Project 2017-07	Alignment with Registration	Registration	Formal	8/1/17	8/30/17	Yes 8/30/17
345	Project 2017-07	Alignment with Registration	MOD-032-1 SAR	Formal	8/1/17	8/30/17	Yes 8/30/17
346	Reliability Guideline	Area Control Error Diversity Interchange Process	ACE Process	Formal	7/18/17	8/31/17	Yes 8/31/17
347	Project 2016-04	Modifications to PRC-025-1	PRC-025-2	Formal	7/25/17	9/7/17	Yes 9/7/17
348	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	7/27/17	9/11/17	Yes 9/11/17
349	Project 2016-02	Modifications to CIP Standard	Technical Rationale and Justification for CIP-012-1	Informal	8/14/17	9/12/17	Yes 9/12/17
350	Project 2016-02	Modifications to CIP Standard	Definition of Control Center	Informal	8/14/17	9/12/17	Yes 9/12/17
351	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	9/8/17	10/23/17	Yes 10/23/17
352	Project 2016-02	Modifications to CIP Standard	CIP-002-6	Formal	9/14/17	10/30/17	Yes 10/30/17
353	Project 2015-09	Establish and Communicate System Operating Limits	Proposed Definitions of System Operating Limit (SOL) and SOL Exceedance	Informal	9/29/17	10/30/17	Yes 10/30/17
354	Project 2016-02	Modifications to CIP Standard	Virtualization	Informal	10/6/17	11/2/17	Yes 11/2/17
355	Project 2015-09	Establish and Communicate System Operating	FAC-010 FAC-011 FAC-014	Formal	9/29/17	11/13/17	Yes 11/13/17

RSC Meeting #18-2, Agenda Item 6.3: Comment History

(As of 6/7/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Limits					
356	Project 2017-01	Modifications to BAL-003-1.1	SAR	Formal	11/2/17	12/1/17	Yes 12/1/17
357	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	10/27/17	12/11/17	Yes 12/11/17
358	Project 2016-02	Modifications to CIP Standard	Technical Rationale/Justification	Informal	11/20/17	12/11/17	Yes 12/11/17
359	Project 2017-03	FAC-008-3 Periodic Review	FAC-008-3	Formal	10/30/17	12/13/17	Yes 12/13/17
360	Project 2016-04	Modifications to PRC-025-1	PRC-025-1	Formal	10/30/17	12/13/17	Yes 12/13/17
361	Project 2017-07	Alignment with Registration	SAR	Formal	12/11/17	1/9/18	Yes 1/9/18
362	Project 2017-05	NUC-001-3	NUC-001-3	Formal	12/15/17	1/29/18	Yes 1/29/18
363	Project 2017-04	INT Periodic Review	INT-004-3.1 INT-006-4 INT-009-2.1 INT-010-2.1	Formal	1/10/18	2/23/18	Yes 2/23/18
364	Project 2017-07	Standards Alignment with Registration	Multiple Standards	Formal	2/1/18	3/2/18	Yes 3/2/18
365	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications (PER) Standards	PER-003-1 PER-004-2	Formal	1/22/18	3/7/18	Yes 3/7/18
366	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	2/23/18	4/23/18	Yes 4/23/18
367	Project 2018-01	Canadian-specific Revisions to TPL-007-2 SAR	TPL-007-2 SAR	Formal	3/30/18	4/30/18	Yes 4/30/18
368	Project 2016-02	Modifications to CIP Standard	CIP-002-6	Formal	3/16/18	4/30/18	Yes 4/30/18
369	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	3/16/18	4/30/18	Yes 4/30/18
370	Project 2016-02	Modifications to CIP Standard	Control Center Definition and Implementation	Formal	3/16/18	4/30/18	Yes 4/30/18

RSC Meeting #18-2, Agenda Item 6.3: Comment History

(As of 6/7/2018)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-NPCC-1

3. **Purpose:** The NPCC Automatic Underfrequency Load Shedding (UFLS) regional Standard establishes more stringent and specific NPCC UFLS program requirements to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document~~To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics~~.

4. **Applicability:**

   4.1. Generator Owner

   4.2. Planning Coordinator

   4.3. Distribution Provider that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program as established by the Planning Coordinators.

   4.4. Transmission Owner that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program as established by the Planning Coordinators.

5. **Effective Date:**

Reference to Implementation Plan ~~For the Eastern Interconnection & Québec Interconnection portions of NPCC excluding the Independent Electricity System Operator (IESO) Planning Coordinator area of NPCC in Ontario, Canada:~~

> ~~The effective date for Requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than January 1, 2016 The effective date for Requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.~~

~~For the Independent Electricity System Operator (IESO) Planning Coordinator's area of NPCC in Ontario, Canada:~~

> ~~All requirements are effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017~~.

B. Requirements

Rationale for Requirement R1: Figure 1 of this document shows the NPCC

~~Adopted by Board of Trustees: February 9, 2012~~

underfrequency criteria for the Eastern Interconnection portion of NPCC. Note that Figure 1 also shows the NERC criteria as defined in the NERC PRC Standard on UFLS.

R1. Each Planning Coordinator in the Eastern Interconnection portion of NPCC shall design an UFLS program having performance characteristics that prevents the frequency from remaining below 59.5 Hz for greater than 30 seconds in accordance with Figure 1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, system studies and/or real-time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1~~ **R1** Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]~~

R2. Each Planning Coordinator shall provide UFLS island boundaries, as identified per the NERC PRC Standard on UFLS, to Distribution Providers, Generator Owners, and Transmission Owners within 30 calendar days of receipt of a request. *[Violation Risk Factor Lower] [Time Horizon: Long Term Planning]*

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

~~**R2** Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]~~

R3. Each Planning Coordinator shall, within 30 calendar days of completion of its UFLS system studies, identify to the Regional Entity all non-BES generation facilities, within its Planning Coordinator Area, that must not trip above the appropriate generator underfrequency trip threshold curve in Figure 2 in order to support UFLS program performance requirements. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M3. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3

R4. Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program, reflecting normal operating conditions, excluding outages. The automatic UFLS program shall be implemented on an island basis for

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each island identified per the NERC PRC Standard on UFLS. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

4.1. The UFLS program shall be implemented by each Distribution Provider and Transmission Owner according to the frequency thresholds, nominal operating times and load shedding amounts specified in Attachment C, Tables 1 through 3 or,

4.2. The program shall be implemented collectively by multiple Distribution Providers or Transmission Owners, as long as they reside in the same UFLS Island identified by the Planning Coordinator per R2. These multiple Distribution Providers or Transmission Owners, via mutual agreement, shall act as a single entity to provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load according to the frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3

~~**R3** Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]~~

M4. Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped in their respective areas, and the corresponding frequency thresholds, on those circuits included in its UFLS program identified in Requirement R4. (Attachment C Tables 1-3).~~**R4** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3.
[Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

R5. Each Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

5.1. Notify its Planning Coordinator within 30 calendar days of recognition.
5.2. Within the following 90 calendar days, determine if tolerances can be met through adjustments and notify the Planning Coordinator.

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5.3. If adjustments are possible, make the adjustments within 180 calendar days after determining that adjustments are possible, and notify the Planning Coordinator when complete, or,

5.4. If adjustments are not possible then:

5.4.1. Each Distribution Provider or Transmission Owner subject to Attachment C, Table 1, shall within 180 calendar days, provide its Planning Coordinator with a technical study that demonstrates that the Distribution Provider's or Transmission Owner's specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the BES, or

5.4.2. Each Distribution Provider or Transmission Owner subject to Attachment C, Table 2 or Table 3, or in the Quebec Interconnection, shall within 90 calendar days, provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with the UFLS program.

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M5. Each Distribution Provider or Transmission Owner shall have evidence such as reports analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

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~~**R5** Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

Rationale for Requirement R6: Operation of underfrequency relays results directly in load being shed, interrupting service to customers. The security of underfrequency relays against misoperation is therefore paramount. The 100 ms minimum time delay specified in R6 serves to prevent premature activation of these relays during short-lived transient frequency excursions that may occur on a localized basis in the absence of a serious system event wherein UFLS would be appropriate. This intentional delay helps to ensure that the relays activate only for frequency excursions that are due to actual system events that require automatic UFLS to reestablish the balance of generation to load.

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R6. Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with a 100 ms minimum time delay. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning].*

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M6. Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum

time delay, in accordance with Requirement R6.~~5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and~~

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~~5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.~~

~~5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and~~

~~5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.~~

~~**R6** Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

Rationale for Requirement R7: An inhibit function provides supervisory control over a UFLS relay. For example, an undervoltage inhibit feature prevents UFLS relay operation if the sensed voltage decreases below an adjustable setting. An undervoltage inhibit function is intended to prevent operation of a UFLS relay when the transmission supply is lost to distribution station feeding many induction motors. Following loss of the transmission supply, motors may support the voltage while the motors coast down in speed. The motors coasting down (ringing down) will look like an Underfrequency event to the relay. The inhibit setting is set to a voltage above which the motor load is expected to sustain. This prevents the Underfrequency relay from tripping and locking out distribution feeder breakers supplying the motor load, between the time the transmission supply line trips and the time when the line recloses to restore the load. Voltages sustained by motors that are coasting down (e.g. 0.70 pu) are typically much lower than voltages at which the UFLS relays are required to operate to meet UFLS performance criteria. However, motor loads supplied by cable

networks typically have higher ring down voltages because of cable charging. Therefore, care must be taken so that the voltage inhibit setting is not higher than the voltage at which UFLS relays are required to operate to meet UFLS performance criteria.

R7. Each Planning Coordinator shall develop and review settings for inhibit thresholds at least once per five calendar years (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M7. Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R7.

R8. Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 calendar days of any changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R8.

R9. Each Distribution Provider and Transmission Owner that receives a notification pursuant to Requirement R8 shall develop and submit an implementation plan for approval by the Planning Coordinator within 90 calendar days of the request from the Planning Coordinator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

~~**R7** Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:~~

~~7.1 Eastern Interconnection – 100 ms~~

~~7.2 Québec Interconnection – 200 ms~~

~~[Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

~~**R8** Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]~~

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~~**R9** Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]~~

R10. Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings provided by the Planning Coordinator in accordance with Requirement R8 and based on the Planning Coordinator approved implementation plan in accordance with R9. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M10. Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets, completed work orders, or other documentation that demonstrates that it meets Requirement R10.

~~**R10** Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]~~

Rationale for Requirement R11: It is recognized that, ideally, the amount of load to be shed in each stage of the UFLS program for every entity should perfectly match that prescribed in this Standard, for all phases of the load cycle, i.e., seasonal (summer vs. winter), weekly (weekday vs. weekend vs. holidays), daily (morning, noon, and night), etc. for all of the identified islands. Practically, however, this is obviously not possible because the load cycles of the various areas and sub-areas within any given island do not perfectly track the load cycle of the overall island. The UFLS program, on the other hand, is designed based on peak conditions for the overall island. The percentages of actual load shedding that would occur for any conditions other than peak, therefore, can only approximate that prescribed in the Standard. This being said, entities are required by R11 to document measured loads in the UFLS program coincident with their own annual peak, whether or not that peak occurs at the same time or in the same season as the peak of the identified island in which their load resides. Using individual entity peaks vs. overall island peaks provides a consistent approach for accounting purposes among the very entities that are responsible for designing and maintaining their UFLS programs.

R11. Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 calendar months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage. The actual net Load shall be coincident with the entity's integrated hourly peak net Load during the previous year, as determined by measuring or calculating Load through the switches that would disconnect load if triggered by the UFLS relays. *[Violation Risk Factor: Lower]*

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[Time Horizon: Long Term Planning] ~~**R11** Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]~~

M11. Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program to demonstrate that it meets Requirement R11.

R12. Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection settings threshold curve in Figure 2, except as otherwise exempted in Requirements R15 and R18. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M12. Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R12.

R13. Each Generator Owner shall transmit the generator underfrequency trip setting and time delay within 45 calendar days of the Planning Coordinator's request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~**R12** Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]~~

M13. Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R13.

R14. Each Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10% shall: *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

14.1. Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 2.

14.2. Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 2.~~**R13** Each Generator Owner shall set each generator underfrequency trip relay, if so equipped,~~

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below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R14 Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

M14. Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R14.

R15. For existing non-nuclear units in service prior to the effective date of this standard, as documented in accordance with Attachments A or B, that have underfrequency protections set to trip above the appropriate curve in Figure 2: [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

15.1. Each Generator Owner shall set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

15.2. Each Generator Owner shall transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

15.3. Each Planning Coordinator in Ontario, Québec and the Maritime Provinces in accordance with Attachment A and each Generator Owner in the New-England States and in New York State in accordance with Attachment B shall arrange for compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of generator(s) due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2

M15. Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R12shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R15.**R15** Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

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~~15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.~~

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~~**R16** Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

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~~16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.~~

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~~16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.~~

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~~16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.~~

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~~**R17** Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

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R16. Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R15.3 for generating units in its respective NPCC area. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M16. Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such asreports, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R16.

R17. Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R15.3 for generating units in its respective NPCC area. *[Violation Risk Factor: Medium]*

[Time Horizon: Long Term Planning]

M17. Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as reports, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R17.

R18. Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 2, based on their licensing design basis, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

18.1. Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8 Hz.

18.2. Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

18.3. Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

M18. Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 2 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R18.

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~~**R18** Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

~~**R19** Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

~~19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.~~

~~19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.~~

19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

R20 The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.

20.2 The buses at which the Load is modeled in the NPCC library power flow case.

20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.

20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.

20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

R21 Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R22 Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R23 Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

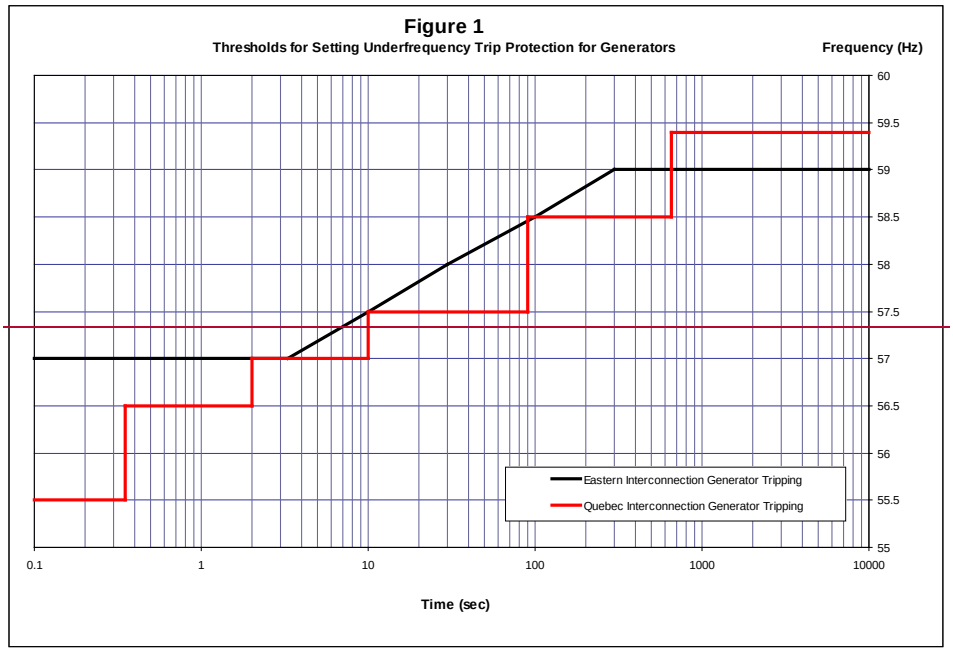

Figure 1
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Eastern Interconnection Frequency Hz
Design Performance Requirements

PRC-006-NPCC-2 Figure 1
Underfrequency Load Shedding Program - Eastern Interconnection
Design Performance Requirements

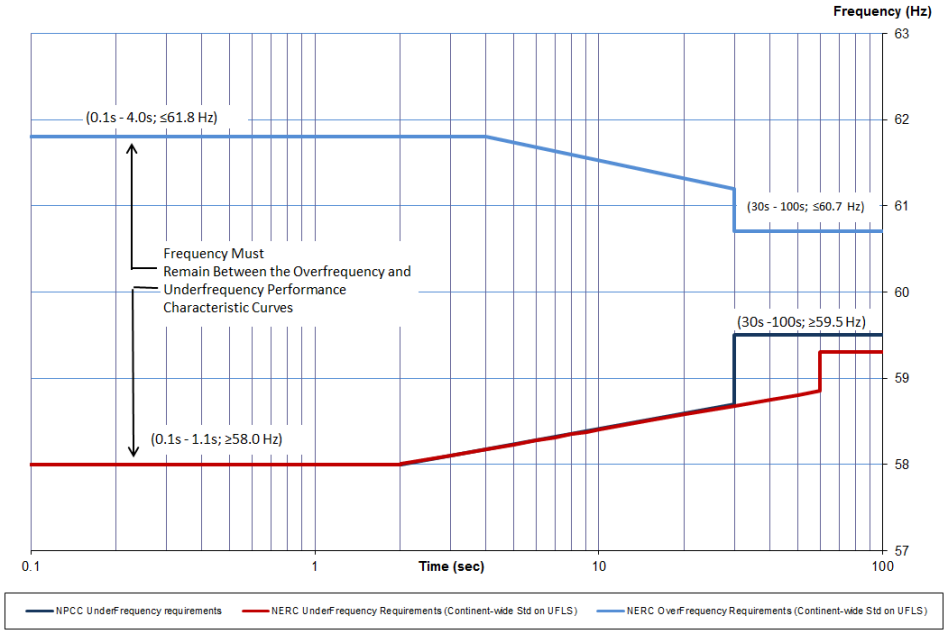

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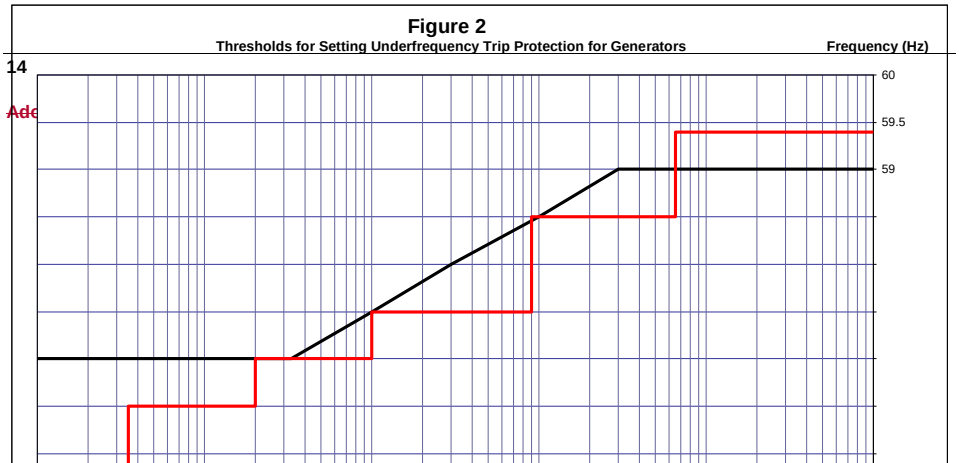
Figure 2
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators



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~~C. Measures~~

M1 Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

M3 Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

M4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).

M5 Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

M6 Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).

M7 Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

M8 Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

M9 Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

M10 Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

M11 Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

M12 Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

M13 Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

M14 Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

M15 Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

M16 Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

M17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

M18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

M19 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

D.C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

1.4. Compliance Monitoring and Assessment Processes

Self -Certifications.

Spot Checking.

Compliance Audits.

Self- Reporting.

Compliance Violation Investigations.

Complaints.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Plannning Coordinator failed to design an UFLS program having performance characteristics that prevent frequency from remaining below 59.5 Hz in accordance with Figure 1.
R2	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC PRC Standard on UFLS but did so more than 30 calendar days and up to and including 40 days following a request.	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC PRC Standard on UFLS but did so more than 40 calendar days but less than and including 50 days following a request.	The Planning Coordinator provided its UFLS island boundaries, as identified per the NERC PRC Standard on UFLS but did so more than 50 calendar days but less than and including 60 days following a request.	The Planning Coordinator failed to provide its UFLS island boundaries, as identified per the NERC PRC Standard on UFLS. within 60 calendar days following a request.
R3	The Planning Coordinator identified to the Regional Entity all non-BES generation facilities within its Planning Coordinator Area that must not trip above the appropriate generator underfrequency trip threshold curve in order to support	The Planning Coordinator identified to the Regional Entity all non-BES generation facilities within its Planning Coordinator Area that must not trip above the appropriate generator underfrequency trip threshold curve in order to support the UFLS program performance	The Planning Coordinator identified to the Regional Entity all non-BES generation facilities within its Planning Coordinator Area that must not trip above the appropriate generator underfrequency trip threshold curve in order to support the UFLS program	The Planning Coordinator identified all non-BES generation facilities within its Planning Coordinator Area that must not trip above the appropriate generator underfrequency trip threshold curve in order to support the UFLS program performance requirements, but failed to inform the Regional

	UFLS program performance requirements, but did so more than 30 calendar daysand up to and including 40 days after completion of the system studies.	requirements, but did so more than 40 days but less than calendar days but less than and including 50 days after completion of the system studies.	performance requirements,, but did so more than 50 calendar days but less than and including 60 days after completion of the system studies.	Entity within 60 calendar days after completion of the system studies. OR The Planning Coordinator did not identify the BES generation facilities within its Planning Coordinator Area that must not trip above the appropriate generator underfrequency trip threshold curve in order to supportUFLS program performance requirements.
R4				The Distribution Provider or Transmission Owner failed to implement the automatic UFLS program on an island basis as specified by Requirement R4, Part 4.1 or Part 4.2.
R5	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations ir Requirement R5, Parts %.1 through Part 5.4 but exceeded the	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations ir Requirement R5, Parts %.1 through Part 5.4 but exceeded the	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program fulfilled its obligations but exceeded the permissible time frame for one or more	The Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program failed to meet all of items in Requirement 5 within 60 calendar days of permissible time for each

	permissible time frame for one or more of the 4 items by a period of up to 10 calendar days but less than or equal to 20 calendar days.	permissible time frame for one or more of the 4 items within a time greater than 20 calendar days but less than or equal to 30 calendar days.	of the 4 items within a time greater than 30 calendar days but less than or equal to 60 calendar days.	item.
R6	The Distribution Provider or Transmission Owner set less than 100% but more than (and including) 95% of its underfrequency relays that are part of its region's UFLS program with a 100 ms minimum time delay.	The Distribution Provider or Transmission Owner set less than 95% but more than (and including) 90% of its underfrequency relays that are part of its region's UFLS program with a 100 ms minimum time delay.	The Distribution Provider or Transmission Owner set less than 90% but more than (and including) 85% of its underfrequency relays that are part of its region's UFLS program with a 100 ms minimum time delay.	The Distribution Provider or Transmission Owner set less than 85% ot its underfrequency relays that are part of its region's UFLS program with a 100 ms minimum time delay.
R7	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 100% but more than (and including) 95% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 95% but more than (and including) 90% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 90% but more than (and including) 85% of relays within its region's UFLS program.	The Planning Coordinator developed or reviewed settings for inhibit thresholds at least once per five calendar years, for less than 85% of relays within its region's UFLS program.
R8	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator	The Planning Coordinator failed to provide to a Transmission Owner or Distribution Provider within its Planning

	area the applicable inhibit thresholds more than 30 calendar days and up to and including 40 calendar days of any changes.	applicable inhibit thresholds more than 40 calendar daysbut less than and including 50 calendar days of any changes.	area the applicable inhibit thresholds more than 50 calendar daysbut less than and including 60 calendar days of any changes.	Coordinator area the applicable inhibit thresholds within 60 calendar days after any changes
R9	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 calendar days and up to and including 100 calendar days following the request.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 calendar days and up to and including 110 calendar days following the request.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 calendar days and up to and including 120 calendar days following the request.	The Distribution Provider or Transmission Owner failed to develop and submit its implementation plan within 120 days following the request.
R10	implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 100% but more than (and including) 95% of UFLS relays.	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 95% but more than (and including) 90% of UFLS relays.	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 90% but more than (and including) 85 % of UFLS relays.	The Distribution Provider or Transmission Owner implemented the inhibit threshold settings provided by the Planning Coordinator in accordance with the Planning Coordinator approved implementation plan for less than 85 % of UFLS relays.
R11	The Distribution Provider or Transmission Owner	The Distribution Provider or Transmission Owner	The Distribution Provider or Transmission Owner	The Distribution Provider or Transmission Owner failed to provide

	provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 15 calendar months but less than (and including) 16 calendar months since last update.	provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 16 calendar months but less than (and including)17 calendar months since last update.	provided to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 more than 17 calendar months but less than (and including)18 calendar months since last update.	to its Planning Coordinator documentation of the actual net Load that would have been shed by the UFLS relays at each UFLS stage as described in Requirement R11 within 18 calendar months since last update.
R12	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection settings threshold curve in Figure 2, except as otherwise exempted.
R13	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 45calendar days and less than (and including) 55 calendar days of the Planning	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 55 calendar days and less than (and including) 65 calendar days of the Planning	The Generator Owner transmitted the generator underfrequency trip setting and time delay more than 65 calendar days and less than (and including) 75 calendar days of the	The Generator Owner failed to transmit the generator underfrequency trip setting and time delay within 75 calendar days of the Planning Coordinator's request.

	Coordinator's request.	Coordinator's request.	Planning Coordinator's request.	
R14	N/A	N/A	The Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10%: Did not: fulfill the obligation of Requirement R14; Part 14.1 OR Did not fulfill the obligation of Requirement R14, Part 14.2.	The Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10%, did not fulfill the obligations of Requirement R15, Part 15.1 and Part 15.2.
R15	N/A	The Generator Owner failed to transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.as specified in Requirement R15, Part 15.2.	The Generator Owner failed to set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations a specified in Requirment 15, Part 15.1	The Planning Coordinator in Ontario, Québec and the Maritime Provinces or the Generator Owner in the New-England States and in New York State failed to arrange for compensatory load shedding as specified in Requirement R15, Part 15.3.
R16	N/A	N/A	N/A	The Planning Coordinator did not apply the methodology described in Attachment A to determine the

				compensatory load shedding that is required.
R17	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R18	N/A	The Generator Owner failed to transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator as specified in Requirement R18, Part 18.3.	The Generator Owner: Failed to set the underfrequency protection as specified in Requirement R18; Part 18.1 OR Failed to set the frequency trip setting upper tolerance as specified in Requirement R18, Part 18.2.	The Generator Owner did not fulfill the obligations of Requirement R18, Part 18.1 and Part 18.2.

PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

    2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..

    2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest

frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

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PRC-006-NPCC-1 Attachment C

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 – 31.5

UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

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1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

Frequency Threshold (Hz)	Total Nominal Operating Time (s)[2]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 – 31.5

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UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

~~UFLS Table 3: Eastern Interconnection~~

~~Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:~~

~~UFLS Stage~~	~~Frequency Threshold (Hz)~~	~~Total Nominal Operating Time (s)[1]~~	~~Load Shed at Stage as % of TO or DP Load~~	~~Cumulative Load Shed as % of TO or DP Load~~
~~1~~	~~59.5~~	~~0.30~~	~~28-50~~	~~28-50~~

~~1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.~~

UFLS Table 4: Quebec Interconnection

	Rate	Frequency (Hz)	MW at peak (*Load must be fixed at all times when above 60% of peak load..)	Mvar at peak	Total Nominal Operating Time (s) [2]
Threshold Stage 1	——	58.5	1000*	1000	0.30
Threshold Stage 2	——	58.0	800*	800	0.30
Threshold Stage 3	——	57.5	800	800	0.30
Threshold Stage 4	——	57.0	800	800	0.30
Threshold Stage 5 (anti-stall)	——	59.0	500	500	20.0
Slope Stage 1	-0.3 Hz/s	58.5	400	400	0.30
Slope Stage 2	-0.4 Hz/s	59.8	800*	800	0.30
Slope Stage 3	-0.6 Hz/s	59.8	800*	800	0.30
Slope Stage 4	-0.9 Hz/s	59.8	800	800	0.30

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Guidelines and Technical Basis:

2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.

Standard PRC-006-3, R4 requires the Planning Coordinator to conduct a UFLS assessment at least once every five years. However, aside from a UFLS islanding event, it does not prescribe other factors or events which could warrant a new UFLS assessment in less than the five years time-frame.

PRC-006-NPCC-01 contained requirements if changes to load distribution impacted UFLS program performance (R21) but did not consider many other factors. The drafting team recommends retiring these requirements (R21, R22, R23) and replacing them with the following guidance.

Significant variations in the following factors could require a Planning Coordinator to conduct a new assessment:

- Changes to the BES that could modify the creation of islands or the severity of events such as new transmission topologies, revised protection schemes or new or revised RAS.
- Unforeseen islanding event
- Real and reactive load distribution (including changes to location of compensatory load shedding)
- Transmission Owner or Distribution Provider's inability to implement the UFLS program within the stated tolerances
- Load characteristics in particular frequency responsive load
- Automatic load restoration
- Generation geographical distribution
- Generator trip settings
- Generation mix in particular non-BES generation that may not be subject to frequency ride-through criteria
- Generator dynamic modeling
- Dynamic VAR device modeling
- HVDC dynamic modeling

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

March 15, 2018

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: ***North American Electric Reliability Corporation***
Petition for Approval of Amended Compliance and Certification Committee Charter
Docket No. RR18-___-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC")[1] hereby submits for Federal Energy Regulatory Commission ("FERC" or "Commission") approval the proposed amended Compliance and Certification Committee ("CCC") Charter. This filing consists of this transmittal letter; Attachment 1, which contains a clean version of the proposed amendments to the CCC Charter; and Attachment 2, which contains a redline version of the proposed amendments.

Proposed Amendments

The proposed amendments to the CCC Charter reflect the participation of CCC observers in NERC audits of the Regional Entities in accordance with Appendix 4A of the NERC Rules of Procedure.[2]

[1] NERC is the Commission-certified electric reliability organization ("ERO") responsible for the development and enforcement of mandatory Reliability Standards. *See North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 342 (D.C. Cir. 2009).

[2] *See* North American Electric Reliability Corp., Rules of Procedure, Appendix 4A at p.2, Audit of Regional Entity Compliance Programs, http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_4A_AuditRegionalEntityCompliancePrograms_20131004.pdf.

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FERC originally approved the CCC Charter in June 2007 in an Order on Compliance Filing,[3] approved a revised CCC Charter in June 2010,[4] and approved a revised CCC Charter in January 2016.[5] As required,[6] NERC is submitting this revised CCC Charter for FERC approval. On February 8, 2018, the NERC Board of Trustees approved the revised CCC Charter contained herein.

Communications

Please address any communications concerning this filing to the persons listed below and place their names on the Commission's official service list:

[3] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,248 (2007), *order on compliance filing*, 121 FERC ¶ 61,033 (2007).

[4] *North American Electric Reliability Corp.*, Docket No. RR10-8-000 (June 10, 2010) (delegated letter order) (accepting NERC filing of amendments to the NERC Rules of Procedure and CCC Charter).

[5] *North American Electric Reliability Corp.*, 152 FERC ¶ 61,142 (2015), Docket No. RR15-11-001 (Jan. 13, 2016) (delegated letter order) (accepting NERC compliance filing).

[6] *North American Electric Reliability Corp.*, 152 FERC ¶ 61,142, at P10 (2015).

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NERC respectfully requests waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure the Commission's to permit the inclusion of more than two people on the service list.[7]

[7] 18 C.F.R. § 385.203(b)(3) (2017).

Conclusion

NERC respectfully requests that the Commission approve the proposed amended CCC Charter.

NERC thanks the Commission for its consideration of this filing. Please contact the undersigned if you have any questions.

Respectfully submitted

/s/ Alexander Kaplen

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Counsel for North American Electric Reliability Corporation

Attachment 1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance and Certification Committee Charter

Filed with FERC for approval on March 15, 2018, in Docket No. RR18-XX-000.

February 8, 2018

RELIABILITY | ACCOUNTABILITY

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Mission

In the capacity of a North American Electric Reliability Corporation (NERC) Board of Trustees (Board)-appointed stakeholder committee serving and reporting directly to the NERC Board, the Compliance and Certification Committee (CCC) will engage with, support, and advise the NERC Board and NERC regarding all facets of the NERC Compliance Monitoring and Enforcement Program (Compliance and Enforcement program), Organization Registration program (Registration program), and Organization Certification program (Certification program). As a committee providing support and advice but otherwise independent of the execution of these programs, the CCC will monitor NERC's adherence to the Rules of Procedure (ROP) for these programs. Also and in a similar manner, as a committee independent of the Reliability Standards development process, the CCC will be the body responsible for monitoring NERC's adherence to the (ROP) regarding the Reliability Standards development process with the exception of appeals of substantive or procedural action or inaction associated with a Reliability Standard or the Standards process as defined in the appeals section of the Standard Processes Manual. The CCC is also responsible for establishing and implementing a program to monitor NERC's compliance with the Reliability Standards that apply to NERC.

Compliance and Certification Committee Functions

To fulfill its mission, the CCC performs the following functions:

1. Organizes and conducts committee meetings directly with NERC staff regarding all facets of the Compliance and Enforcement, Registration, and Certification programs;[1]
2. Provides comments and recommendations to the NERC Board and NERC staff;
3. Provides comments to NERC with respect to stakeholders' perception of the policies, practices, and effectiveness of the Compliance and Enforcement program, Registration program, and Certification program;
4. Recommends revisions of the electric reliability organization (ERO) ROP related to the Compliance and Enforcement program, Registration program, and Certification program to the NERC Board;
5. Establishes and implements programs to monitor:[2]
    a. NERC's adherence to Section 405 for Compliance Monitoring and Enforcement, including but not limited to the uniform CMEP (Appendix 4C) and the Sanction Guidelines (Appendix 4B).
    b. NERC's adherence to Section 506 for Organization Registration and Certification, including but not limited to the Organization Registration and Certification Manual (Appendix 5A).
    c. NERC's adherence to Section 300 of the ROP regarding the Reliability Standards development process with the exception of appeals of substantive or procedural action or inaction associated with a Reliability Standard or the Reliability Standards process as defined in the appeals section of the Reliability Standards Development Procedure. Committee members who have participated in the development process for a particular Reliability Standard shall not participate in the committee's monitoring of that process.
    d. NERC's compliance with the Reliability Standards that apply to NERC.
6. Serves as the hearing body for any contest regarding findings of or penalties or sanctions for violation(s) of Reliability Standard(s) where NERC is directly monitoring the entity for compliance with those standards (registered entity by agreement with a Regional Entity or absent a delegation agreement; the Region itself where approved standards are applicable to the Region) as described in Section 408 of the NERC ROP;
7. As directed by the NERC Board, serves as the mediator for any disagreements between NERC and the Regional Entities concerning NERC performance audits of Regional Entities' compliance programs. When directed by the Board to serve as mediator, the committee chair will appoint three disinterested members of the committee to meet with representatives of NERC and the Regional Entity to attempt to resolve the matter.
8. At the discretion of the CCC, participates as an observer in Regional Entity Compliance Program audits executed by NERC's Internal Audit and Corporate Risk Management function, consistent with Appendix 4A of the ROP.
9. Actively supports the Standards Committee in the development of new and revised standards by providing a pool of qualified compliance oriented personnel for participation in the compliance administration element phase of the standards development process;

[1] Meetings are conducted under Section 4 of this Charter.

[2] Monitoring by the CCC is ongoing and does not preclude, interfere with or replace, in whole or in part, the NERC Board's responsibility to conduct and provide such reviews of these programs as required by Federal Energy Regulatory Commission (the Commission) regulations, 18 C.F.R. § 39.3.c: "The Electric Reliability Organization shall submit an assessment of its performance three years from the date of certification by the Commission, and every five years thereafter."

10. Provides assistance to NERC and the Regional Entities to implement the Compliance and Enforcement, Registration, and Certification programs; and
11. Undertakes assignments from the Board or the Board's Compliance Committee related to compliance and enforcement, organization registration, organization certification, and standards development.

Membership

Goals

The CCC provides for balanced discussion, commentary, and recommendations on compliance issues by bringing together a wide diversity of opinions and perspectives from NERC member sector experts who have particular familiarity, knowledge, and experience in the area of compliance and NERC Standards and Regional Standards.

Appointment and Terms of Service

Members are appointed to the committee by the NERC Board and serve on the committee at the pleasure of the Board. Member terms are the lesser of three years from appointment or interim approval (Section 5.b), replacement, or removal by the Board. Members may be reappointed at the conclusion of a term. There is no limitation on the number of times a member may be reappointed. A member may be recommended to the Board for reappointment by the Nominating Subcommittee by self- nomination. To the extent practicable, member terms will be staggered such that approximately one-third of the committee is subject to reappointment or replacement each year.

Qualifications

Individuals deemed qualified to serve on the committee will generally include senior-level industry experts who have particular familiarity, knowledge, and experience in the area of compliance, compliance enforcement, compliance administration and management, organization responsibilities and registration, organization certification, and NERC Standards and Regional Standards. These individuals should be involved with internal compliance programs within their respective organizations.

Expectations

Committee members are expected to represent the interests of the sector they represent to the best of their ability and judgment. In addition to the duties, rights, and privileges described elsewhere in this charter, committee members will:

1. Act consistently during meetings with the procedures in this manual and Robert's Rules of Order;
2. Demonstrate and provide knowledge and expertise in support of committee activities;
3. Adjudicate in a fair and unbiased manner that meets applicable legal and due process requirements when participating in hearing procedures conducted under the NERC ROP Section 408;
4. Solicit comments and opinions from constituents and groups of constituents or trade organizations represented by the member and convey them to the committee;
5. Respond promptly to all committee requests, including requests for reviews, comments, and votes on issues before the committee;
6. Arrange for a proxy to attend and vote at committee meetings in the member's absence; and
7. Respond promptly to all requests to register for committee meetings.

Representation

The membership structure of the CCC will be modeled upon the membership structure of the NERC Member Representatives Committee (MRC) as described in NERC's Bylaws (the Bylaws) Article VIII Section 2 [see Attachment A]. This should produce a committee that has an appropriate balance of entities subject to compliance with the NERC Reliability Standards and NERC's Compliance and Enforcement program, and others affected by the Standards and the Compliance and Enforcement program.

Regional Entities

Each Regional Entity, or the applicable regional organization if no Regional Entity exists for the geographic area, may nominate one member to the committee. In aggregate, the sector will have voting strength equivalent to two members. The voting weight of each Regional member's vote will be set such that the sum of the weight of all available Regional members' votes is two votes.

Canadian Representation

The committee structure will include representation by Canadians as laid out in Article VIII Section 4 of the Bylaws.

NERC Membership

Users, owners, and operators of the bulk power system are subject to the Compliance, Registration, and Certification programs regardless of whether they are NERC members. It is expected that committee members will generally be from organizations who are NERC members; however, committee members may be non-members of NERC who are subject to the qualifications identified herein and meeting requirements laid out in the Bylaws for non-NERC-member participation in the MRC.

Selection

The CCC will conduct open nominations processes to receive nominations to fill any membership vacancies. Prospective members of the committee may be identified to the CCC via any means the committee finds acceptable, including solicited or unsolicited nomination by a recognized industry group or association, general open solicitation by the committee for nomination(s), individuals' self-nomination, directed solicitation by the committee to an individual or individuals, or referral by the Board or other NERC body or committee.

Nominating Subcommittee

The CCC will annually appoint a Nominating Subcommittee to identify, qualify, and recommend individuals to fill sector representative vacancies on the committee or, when required, to serve as the chair or vice chair of the committee. The subcommittee will identify the individuals they are recommending to the full CCC for review. Individuals recommended by the subcommittee for appointment to the committee must be approved by the Board.

Interim Approval

Upon approval of the committee, individuals identified and selected by the Nominating Subcommittee for membership on the committee may serve as members on an interim basis pending their appointment by the Board.

Expertise

When selecting individuals to recommend for committee membership, the Nominating Subcommittee will seek to engage individuals who, in aggregate, provide the committee with a level and breadth of expertise sufficient to achieve its goals and fulfill its scope and responsibilities while respecting other important factors such as industry sector, Region, interconnection, and country.

Regional Entity Members

Each Regional Entity, or the applicable regional organization if no Regional Entity exists for the geographic area, may nominate an individual to serve as a member representing their organization. The Nominating Subcommittee will defer to these nominations. The nomination is non-binding upon the Board. Vacancies on the committee will exist where the Regional Reliability Organization or Regional Entity has not provided a nomination.

Canadian Members

The Nominating Subcommittee will endeavor to attract and engage Canadians with suitable qualifications and expertise in adequate numbers to satisfy Article VIII Section 4 of the Bylaws. Recognized Canadian organizations

such as the Canadian Electricity Association and Canada's Energy and Utility Regulators will be consulted and solicited for assistance in recruiting Canadians to serve on the committee. All members considered to be serving as Canadians on the committee will be expected to have an endorsement, as appropriate, of such an organization. Canadian representatives should be capable of representing Canadian viewpoints in committee activities, in addition to the sector that they otherwise represent. Consistent with practice regarding the MRC, the Board may appoint additional Canadian individuals to the committee towards satisfying Article VIII Section 4 of the Bylaws.

Industry Sector Members

The Nominating Subcommittee will assess the qualifications of nominees and select individuals to recommend to the NERC Board for appointment to the committee. The subcommittee may give preference to candidates nominated by organizations generally considered by the industry as representative of a broad cross-section of the industry sector in question, such as an industry trade association. A NERC Member sector may elect to identify sector representatives for nomination to the Nominating Subcommittee through a process approved by the NERC Board.

General Nominations and Appointment Process

The committee's secretary administers the general nominations process.

Requesting Nominations

The NERC staff will request nominations and will forward all nominations received to the Nominating Subcommittee. The Nominating Subcommittee will then prepare its recommended slate of members. The recommended slate will be reviewed by the whole committee for information purposes before it is submitted to the Board. The committee may approve the slate to serve as members on an interim basis, pending appointment by the Board at the Board's earliest convenience, but will not otherwise act on the slate.

Board Approval

The Nominating Subcommittee will present the recommended committee membership slate to the Board for approval. If the Board approves the recommended committee slate, each member on the slate is appointed. The Board may also appoint members individually as needed to meet membership balance and fill vacancies.

Vacancies and Non-participation

The committee's secretary will administer the nominations process for vacancies on the committee.

Addressed on an Ongoing Basis

Vacancies on the committee can be addressed on an ongoing basis through receipt and consideration of both solicited and unsolicited nominations for the vacant positions.

Role of the Nominating Subcommittee

Nominations received for vacancies will be vetted by the Nominating Subcommittee in the same manner as general nominations. The subcommittee may subsequently and individually recommend nominees they deem qualified to the NERC Board for consideration for appointment to the committee. Existing committee members may also approve such individuals to serve as members on an interim basis pending full appointment by the Board.

Resignations

By the Member

In the event a member can no longer serve on the committee, that member will submit a written resignation to the committee chair or the secretary.

Requested by the Chair

The chair may request any committee member who ceases to participate in the committee, as indicated by not attending or sending a proxy for two consecutive meetings, to submit a resignation or to request continuation of membership with an explanation of extenuating circumstances. If a written response is not received within 30 days of the chair's request, the lack of response will be considered a resignation.

Referral to the Nominating Subcommittee

The committee chair will refer the vacancy resulting from a resignation to the Nominating Subcommittee of the committee. If a recent list of nominations is available to the Nominating Subcommittee that it deems to be valid, the subcommittee will recommend a replacement nominee; otherwise, the subcommittee will request NERC staff prepare a new solicitation for nominations to fill that position. The Nominating Subcommittee will follow the previously stated criteria in recommending a replacement.

By the Board

Committee members serve at the pleasure of the Board who may request resignation from, remove, or replace a member from the committee, as the Board deems appropriate.

Interim Approval

The committee chair may seek a vote of the committee to allow the proposed replacement member to be seated, pending appointment of the replacement at the Board's next scheduled meeting.

Proxies

A substitute representative, or proxy, may attend and vote during all or a portion of a committee meeting in lieu of a voting member provided the absent member notifies the committee chair, vice chair, or secretary of the proxy.

Notification

Such notification will be in writing (electronic medium is acceptable). The proxy representatives and their affiliation will be named in the correspondence.

Serving as Proxy

A voting member of a committee may not serve as a proxy for another voting member on the same committee (i.e. a member may not cast more than their own vote).

Exclusions

Regional Entity Staff

Regional Entity staff members who administer any portion of the Compliance and Enforcement program, Registration program, or Certification program for that Regional Entity, or for any other Regional Entity, may not serve as a member of the CCC.

Organizations

No two individuals from the same organization, or affiliated organizations, may serve concurrently on the committee. Any committee member who has a membership conflict of this nature is obligated to notify the committee secretary, who shall inform the committee chair. Members impacted by such a conflict, such as through a merger of organizations, may confer between themselves to determine which member should resign from the committee and notify the committee secretary and chair; however, if both members are within the same industry sector and cannot reach an amicable solution by determining the member to remain, the Nominating Subcommittee will review the qualifications of each member and propose the member to remain to the full committee who will determine which member shall continue to serve, subject to Board approval. If the conflict is not resolved in a timely manner by the impacted members, the committee chair shall notify all members of the

affected industry sectors recommending actions to resolve the conflict. If the membership conflict is still unresolved, the committee chair shall take the conflict to the NERC Board for resolution.

NERC Staff

The Director of Compliance Assurance shall not be a member of the committee or vote on committee business. The Director of Compliance Assurance and the secretary shall be recused from participating in any committee activity that involves monitoring of NERC's adherence to ROP or activity that the Director of Compliance Assurance oversees. If the NERC staff coordinator has been recused from participating in a Committee activity, the chair shall appoint another member of the committee as acting secretary for any meetings or other activities from which the NERC staff coordinator is recused.

Changes in Member Affiliation

A committee member whose affiliation has changed may retain the membership position under these circumstances:

1. The new organization is in the same industry sector, and
2. The member meets all other membership requirements.

Conflict of Interest

No committee member may have a conflict of interest that would impair his or her ability to fulfill obligations under this charter. Any committee member who knows of any form of membership conflict, such as working for an entity affiliated with that of another committee member, will notify the committee chair within 10 business days of obtaining that knowledge.

Meetings

In the absence of specific provisions in this manual, all committee meetings will follow Roberts Rules of Order.

Quorum

Two-thirds Requirement

The quorum necessary for transacting business at meetings of the committee is two-thirds of the voting members currently on the committee's roster.

Interim Basis

Voting members approved by the committee on an interim basis, pending appointment by the Board, will be counted in the determination of a quorum.

Lack of Quorum

If a quorum is not present at the beginning of the meeting, the committee may not take any actions requiring a vote by the committee; however, the chair may, with the consent of the members present, elect to allow discussion of the agenda items.

Voting

Actions by members of the committee will be approved upon receipt of the affirmative vote of two-thirds of the votes present (including proportional votes by Regional Representatives) at any meeting at which a quorum is present.

Antitrust Guidelines

All persons attending or otherwise participating in a NERC committee meeting will act in accordance with NERC's Antitrust Compliance Guidelines at all times during the meeting.

Open Meetings

NERC committee meetings will be open to the public, except as noted below under Confidential Information.

Confidential Sessions

At the discretion of the CCC chair, a meeting or portion of a meeting may have attendance limited based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive information or confidential information to one or more parties. All hearings of compliance matters will be confidential sessions. Confidential information will only be disclosed as provided by NERC ROP 1500. Confidentiality agreements may also be applied, as necessary, to protect sensitive information or confidential information.

Types of Meetings

Meetings may be conducted in person, by conference call, or by other means. The procedures contained in this manual will apply to all meetings regardless of how they are conducted.

Majority and Minority Views

All members of a committee will be given the opportunity to provide alternative views on an issue. The results of committee actions, including recorded minutes, will reflect the majority as well as any minority views of the committee members. The chair will communicate both the majority and any minority views in presenting results to the Board.

Action Without a Meeting

Two-thirds Majority

Any action required or permitted at a meeting of the committee may be taken without a meeting if two-thirds of the total votes available to the members of the CCC (including the proportional votes available to Regional Representatives) approve taking the action outside of a meeting.

Procedure

Such action without a meeting will be performed by mail or electronic ballot (e.g., telephone, fax, email, or Internet) and will be recorded in the minutes as a roll call ballot. The secretary will announce the action required at least 10 days before the date on which the action is to be voted. As time permits, members should be allowed a window of 10 business days to vote. The secretary will provide the results of such an action within 10 business days of the close of the voting period.

Officers and Staff

General

Number of Positions

The committee will have two officers and one secretary.

Officers

The committee officers will be one chair and one vice chair.

Executive

The committee shall retain an Executive Committee consisting of the committee officers, subcommittee chairs, secretary, and the Director of Compliance Assurance.

Secretary

The NERC staff coordinator will serve as the committee's secretary.

Voting of Officers

The committee chair and vice chair are voting members of the committee.

Officers Nominated by the Nominating Subcommittee

The CCC Nominating Subcommittee will recommend a chair and a vice chair who are then appointed by the NERC Board for a two-year term. The term of the chair and the vice chair, except for the first year, will begin on July 1 and end on June 30.

Officers as Sector Representatives

The chair and vice chair are selected from the membership of the committee and, in addition to their chair or vice chair responsibilities, will continue to serve as a member for the sector for which they were appointed to the committee.

Chair

The chair will direct and provide general supervision of committee activities, including the following:

1. Coordinate the schedule of all committee meetings, including approval of meeting duration and location;
2. Develop committee agendas and rule on any deviation, addition, or deletion from a published agenda;
3. Preside at and manage committee meetings, including the nature and length of discussion, recognition of speakers and proxies, motions, and voting;
4. Will lead or direct the conduct of any hearings and the preparation of any adjudicatory documents by the committee under Section 408 of the NERC ROP;
5. Will ensure actions and undertakings by the committee under the NERC ROP Section 408 meet all applicable legal and due process requirements;
6. Will act as spokesperson for the committee at forums inside and outside of NERC; and
7. May attend meetings of the NERC Board when necessary to report to the Board on committee activities.

Vice Chair

The vice chair will assume the responsibilities of the chair under the following conditions:

1. At the discretion of the chair (for brief periods of time);

2. When the chair is absent or temporarily unable to perform the chair's duties; or
3. When the chair is permanently unavailable or unable to perform the chair's duties. In the case of a permanent change, the vice chair will continue to serve until a new chair is nominated and selected by the Board.

Staff Coordinator

A member of the NERC staff will be selected by NERC's Director of Compliance Assurance to serve as the staff coordinator and secretary of the committee. The staff coordinator is not a committee member and does not have a vote. Under the direction of the committee executive and applicable NERC bylaws, guidelines, and ROP, the staff coordinator will do the following:

1. Manage the day-to-day operation and business of the committee;
2. Prepare and distribute the notices of the committee meetings, prepare the meeting agenda, and prepare and distribute the minutes of the committee meetings; and
3. Act as the committee's parliamentarian.

Nominating Subcommittee

Appointment

The CCC will annually appoint a Nominating Subcommittee.

Five Members

The subcommittee will consist of five members nominated by the committee chair and approved by the committee. The chair of the subcommittee will be selected by the CCC chair from among the five subcommittee members.

Appointed Annually

The chair will appoint the subcommittee members at the first regular meeting of the committee of the calendar year.

Length of term

The subcommittee members will serve for up to 14 months or until a new Nominating Subcommittee is authorized, whichever is earlier.

Duties

In addition to the duties, rights, and privileges described elsewhere in this manual, members of the Nominating Subcommittee will:

1. Prepare a slate of committee officer candidates for submission to the NERC Board for approval, and
2. Prepare a slate of recommended individuals to fill designated committee vacancies as required.

Subordinate Groups

Committee Organization

The CCC organizational structure will be arranged as allowed in the NERC Bylaws to support a superior-subordinate hierarchy that is ordered as follows: a committee, a subcommittee, a working group, and a task force, with a committee being primary and a task force being quaternary.

Subgroups

The committee may establish subcommittees, working groups, and task forces as necessary. The committee chair may also form any of these subordinate groups on behalf of the committee. The committee will be the responsible sponsor of all subordinate subcommittees, working groups, or task forces it may create, or that its subordinate subcommittees and working groups may create. The committee will keep the Board informed of all groups subordinate to the committee.

Subcommittees

The committee may establish subcommittees to which the committee may delegate some of the committee's broadly defined continuing functions. The committee will approve the scope of each subcommittee it forms. The committee chair will appoint the subcommittee officers (typically a chair and a vice chair) for a specific term (generally two years). The subcommittee officers may be reappointed for up to two additional terms. The subcommittee will work within its assigned scope and be accountable for the responsibilities assigned to it by the committee. The formation of a subcommittee, due to the permanency of the subcommittee, will be approved by the Board.

Working Groups

The committee or any of its subcommittees may delegate specific continuing functions to a working group. The sponsoring committee or subcommittee will approve the scope of each working group it forms. The chair of the sponsoring committee or subcommittee will appoint the working group officers (typically a chair and a vice chair) for a specific term (generally two years). The working group officers may be reappointed for up to two additional terms. The sponsoring committee or subcommittee will conduct a "sunset" review of each working group every two years. The working group will be accountable for the responsibilities assigned to it by the committee or subcommittee and will, at all times, work within its assigned scope.

Task Forces

The committee, subcommittee, or working group may assign specific work of a finite duration to a task force. The sponsoring committee, subcommittee, or working group will approve the scope of each task force it forms. The chair of the sponsoring committee, subcommittee, or working group will appoint the task force officers (typically a chair and a vice chair). Each task force will have a finite duration, normally less than one year. The sponsoring group will review the task force scope at the end of the expected duration and at each subsequent meeting of the sponsoring group after that until the task force is retired. Action of the task force sponsoring group is required to continue the task force past its defined duration. The sponsoring group should consider promoting to a working group any task force that is required to work longer than one year.

Membership and Representation

The membership of each subcommittee, working group, and task force should be established to address the need for expertise and balance of interests. Each group's membership requirements will be defined within the group's approved scope.

As a general guide, the broader the group's scope, the more emphasis there should be on balancing of interests. Therefore, subcommittees would be expected to have the broadest representation of appropriate industry

sectors, while a task force may be more focused on simply having the necessary expertise, and a working group may be somewhere between.

Each member of a subordinate group, and its officers, will be appointed by the chair of the sponsoring committee or group.

To the extent subgroup membership is of a representative nature, recommendations for staffing of the group should be provided in a manner consistent with the principles outlined in the staffing of a committee, including the use of an open nominations process. Regional Entity representatives should be recommended by the Regional Entity and Canadian representatives by the Canadian Electricity Association.

Preference may also be given to representatives recommended by broadly-based industry associations.

To the extent that subgroup membership is based on providing requisite expertise, the chair of the sponsoring committee or group may appoint members based on the relevant technical qualifications.

Procedures

Subcommittees, working groups, and taskforces will conduct business in a manner consistent with all applicable sections of this manual and Robert's Rules of Order.

Hearings

General

The CCC will conduct hearings, as necessary, to fulfill its function of serving as the hearing body for any contest between NERC and a Regional Entity regarding NERC findings, penalties, or sanctions for violation(s) of Reliability Standard(s) by the Regional Entity as described in Section 408 of the NERC ROP.

Hearing Procedure

Unless specifically identified otherwise elsewhere in this charter, the CCC's hearing procedure shall follow the hearing procedure mandated and approved by jurisdictional authorities for use by NERC and the Regional Entities in the Compliance and Enforcement program.

Hearing Panel

The committee shall not have a standing hearing panel. When a hearing is to be conducted, the CCC shall select five members to serve as the adjudicatory panel for that hearing. Members to serve on the panel shall be selected by vote of a valid quorum of the committee. Voting members of the committee at arm's length from parties to the hearing may be nominated or volunteer to stand for selection to the hearing panel. One or more alternates may also be selected, as the committee deems appropriate for the circumstances. A member may serve on more than one panel concurrently. A panel is disbanded upon conclusion of the hearing proceedings for which it was formed.

Attachment A

CCC Membership Structure

Primary Sector	Sub-Sector	Number of Members	Full Voting	Proportional Voting	Non-Voting
Investor-Owned Utility		2	X		
State/Municipal Utility		2	X		
Cooperative Utility		2	X		
Federal or Provincial Utility/Federal Power Marketing Administration		2	X		
Transmission Dependent Utility		2	X		
Merchant Electricity Generator		2	X		
Electricity Marketer		2	X		
Large End-use Electricity Customer		2	X		
Small End-use Electricity Customer		2	X		
Independent System Operator/Regional Transmission Organization		2	X		
Regional Entity	FRCC	1		X	
	RFC	1		X	
	ERCOT	1		X	
	MRO	1		X	
	NPCC	1		X	
	SERC	1		X	
	SPP	1		X	
	WECC	1		X	
Government	U.S. State	2	X		
	U.S. Federal	2			X
	Canadian Provincial	1			X
	Canadian Federal	1			X
Total		**34**			

Attachment 2

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance and Certification Committee Charter

Filed with FERC for approval on ~~November 17, 2015~~March 15, 2018, in Docket No. RR18~~5~~-XX~~11~~-00~~01~~.

~~November 5, 2015~~February 8, 2018

RELIABILITY | ACCOUNTABILITY

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Mission

In the capacity of a North American Electric Reliability Corporation (NERC) Board of Trustees (Board)-appointed stakeholder committee serving and reporting directly to the NERC Board, the Compliance and Certification Committee (CCC) will engage with, support, and advise the NERC Board and NERC regarding all facets of the NERC Compliance Monitoring and Enforcement Program (Compliance and Enforcement program), Organization Registration program (Registration program), and Organization Certification program (Certification program). As a committee providing support and advice but otherwise independent of the execution of these programs, the CCC will monitor NERC's adherence to the Rules of Procedure (ROP) for these programs. Also and in a similar manner, as a committee independent of the Reliability Standards development process, the CCC will be the body responsible for monitoring NERC's adherence to the (ROP) regarding the Reliability Standards development process with the exception of appeals of substantive or procedural action or inaction associated with a Reliability Standard or the Standards process as defined in the appeals section of the Standard Processes Manual. The CCC is also responsible for establishing and implementing a program to monitor NERC's compliance with the Reliability Standards that apply to NERC.

Compliance and Certification Committee Functions

To fulfill its mission, the CCC performs the following functions:

1. Organizes and conducts committee meetings directly with NERC staff regarding all facets of the Compliance and Enforcement, Registration, and Certification programs;[1]
2. Provides comments and recommendations to the NERC Board and NERC staff;
3. Provides comments to NERC with respect to stakeholders' perception of the policies, practices, and effectiveness of the Compliance and Enforcement program, Registration program, and Certification program;
4. Recommends revisions of the electric reliability organization (ERO) ROP related to the Compliance and Enforcement program, Registration program, and Certification program to the NERC Board;
5. Establishes and implements programs to monitor:[2]
    a. NERC's adherence to Section 405 for Compliance Monitoring and Enforcement, including but not limited to the uniform CMEP (Appendix 4C) and the Sanction Guidelines (Appendix 4B).
    b. NERC's adherence to Section 506 for Organization Registration and Certification, including but not limited to the Organization Registration and Certification Manual (Appendix 5A).
    c. NERC's adherence to Section 300 of the ROP regarding the Reliability Standards development process with the exception of appeals of substantive or procedural action or inaction associated with a Reliability Standard or the Reliability Standards process as defined in the appeals section of the Reliability Standards Development Procedure. Committee members who have participated in the development process for a particular Reliability Standard shall not participate in the committee's monitoring of that process.
    d. NERC's compliance with the Reliability Standards that apply to NERC.
6. Serves as the hearing body for any contest regarding findings of or penalties or sanctions for violation(s) of Reliability Standard(s) where NERC is directly monitoring the entity for compliance with those standards (registered entity by agreement with a Regional Entity or absent a delegation agreement; the Region itself where approved standards are applicable to the Region) as described in Section 408 of the NERC ROP;
7. As directed by the NERC Board, serves as the mediator for any disagreements between NERC and the Regional Entities concerning NERC performance audits of Regional Entities' compliance programs. When directed by the Board to serve as mediator, the committee chair will appoint three disinterested members of the committee to meet with representatives of NERC and the Regional Entity to attempt to resolve the matter.
8. At the discretion of the CCC, participates as an observer in Regional Entity Compliance Program audits executed by NERC's Internal Audit and Corporate Risk Management function, consistent with Appendix 4A of the ROP.
9. Actively supports the Standards Committee in the development of new and revised standards by providing a pool of qualified compliance oriented personnel for participation in the compliance administration element phase of the standards development process;

[1] Meetings are conducted under Section 4 of this Charter.

[2] Monitoring by the CCC is ongoing and does not preclude, interfere with or replace, in whole or in part, the NERC Board's responsibility to conduct and provide such reviews of these programs as required by Federal Energy Regulatory Commission (the Commission) regulations, 18 C.F.R. § 39.3.c: "The Electric Reliability Organization shall submit an assessment of its performance three years from the date of certification by the Commission, and every five years thereafter."

~~9.~~10. Provides assistance to NERC and the Regional Entities to implement the Compliance and Enforcement, Registration, and Certification programs; and

~~10.~~11. Undertakes assignments from the Board or the Board's Compliance Committee related to compliance and enforcement, organization registration, organization certification, and standards development.

Membership

Goals

The CCC provides for balanced discussion, commentary, and recommendations on compliance issues by bringing together a wide diversity of opinions and perspectives from NERC member sector experts who have particular familiarity, knowledge, and experience in the area of compliance and NERC Standards and Regional Standards.

Appointment and Terms of Service

Members are appointed to the committee by the NERC Board and serve on the committee at the pleasure of the Board. Member terms are the lesser of three years from appointment or interim approval (Section 5.b), replacement, or removal by the Board. Members may be reappointed at the conclusion of a term. There is no limitation on the number of times a member may be reappointed. A member may be recommended to the Board for reappointment by the Nominating Subcommittee by self- nomination. To the extent practicable, member terms will be staggered such that approximately one-third of the committee is subject to reappointment or replacement each year.

Qualifications

Individuals deemed qualified to serve on the committee will generally include senior-level industry experts who have particular familiarity, knowledge, and experience in the area of compliance, compliance enforcement, compliance administration and management, organization responsibilities and registration, organization certification, and NERC Standards and Regional Standards. These individuals should be involved with internal compliance programs within their respective organizations.

Expectations

Committee members are expected to represent the interests of the sector they represent to the best of their ability and judgment. In addition to the duties, rights, and privileges described elsewhere in this charter, committee members will:

1. Act consistently during meetings with the procedures in this manual and Robert's Rules of Order;
2. Demonstrate and provide knowledge and expertise in support of committee activities;
3. Adjudicate in a fair and unbiased manner that meets applicable legal and due process requirements when participating in hearing procedures conducted under the NERC ROP Section 408;
4. Solicit comments and opinions from constituents and groups of constituents or trade organizations represented by the member and convey them to the committee;
5. Respond promptly to all committee requests, including requests for reviews, comments, and votes on issues before the committee;
6. Arrange for a proxy to attend and vote at committee meetings in the member's absence; and
7. Respond promptly to all requests to register for committee meetings.

Representation

The membership structure of the CCC will be modeled upon the membership structure of the NERC Member Representatives Committee (MRC) as described in NERC's Bylaws (the Bylaws) Article VIII Section 2 [see Attachment A]. This should produce a committee that has an appropriate balance of entities subject to compliance with the NERC Reliability Standards and NERC's Compliance and Enforcement program, and others affected by the Standards and the Compliance and Enforcement program.

Regional Entities

Each Regional Entity, or the applicable regional organization if no Regional Entity exists for the geographic area, may nominate one member to the committee. In aggregate, the sector will have voting strength equivalent to two members. The voting weight of each Regional member's vote will be set such that the sum of the weight of all available Regional members' votes is two votes.

Canadian Representation

The committee structure will include representation by Canadians as laid out in Article VIII Section 4 of the Bylaws.

NERC Membership

Users, owners, and operators of the bulk power system are subject to the Compliance, Registration, and Certification programs regardless of whether they are NERC members. It is expected that committee members will generally be from organizations who are NERC members; however, committee members may be non-members of NERC who are subject to the qualifications identified herein and meeting requirements laid out in the Bylaws for non-NERC-member participation in the MRC.

Selection

The CCC will conduct open nominations processes to receive nominations to fill any membership vacancies. Prospective members of the committee may be identified to the CCC via any means the committee finds acceptable, including solicited or unsolicited nomination by a recognized industry group or association, general open solicitation by the committee for nomination(s), individuals' self-nomination, directed solicitation by the committee to an individual or individuals, or referral by the Board or other NERC body or committee.

Nominating Subcommittee

The CCC will annually appoint a Nominating Subcommittee to identify, qualify, and recommend individuals to fill sector representative vacancies on the committee or, when required, to serve as the chair or vice chair of the committee. The subcommittee will identify the individuals they are recommending to the full CCC for review. Individuals recommended by the subcommittee for appointment to the committee must be approved by the Board.

Interim Approval

Upon approval of the committee, individuals identified and selected by the Nominating Subcommittee for membership on the committee may serve as members on an interim basis pending their appointment by the Board.

Expertise

When selecting individuals to recommend for committee membership, the Nominating Subcommittee will seek to engage individuals who, in aggregate, provide the committee with a level and breadth of expertise sufficient to achieve its goals and fulfill its scope and responsibilities while respecting other important factors such as industry sector, Region, interconnection, and country.

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such as the Canadian Electricity Association and Canada's Energy and Utility Regulators will be consulted and solicited for assistance in recruiting Canadians to serve on the committee. All members considered to be serving as Canadians on the committee will be expected to have an endorsement, as appropriate, of such an organization. Canadian representatives should be capable of representing Canadian viewpoints in committee activities, in addition to the sector that they otherwise represent. Consistent with practice regarding the MRC, the Board may appoint additional Canadian individuals to the committee towards satisfying Article VIII Section 4 of the Bylaws.

Industry Sector Members

The Nominating Subcommittee will assess the qualifications of nominees and select individuals to recommend to the NERC Board for appointment to the committee. The subcommittee may give preference to candidates nominated by organizations generally considered by the industry as representative of a broad cross-section of the industry sector in question, such as an industry trade association. A NERC Member sector may elect to identify sector representatives for nomination to the Nominating Subcommittee through a process approved by the NERC Board.

General Nominations and Appointment Process

The committee's secretary administers the general nominations process.

Requesting Nominations

The NERC staff will request nominations and will forward all nominations received to the Nominating Subcommittee. The Nominating Subcommittee will then prepare its recommended slate of members. The recommended slate will be reviewed by the whole committee for information purposes before it is submitted to the Board. The committee may approve the slate to serve as members on an interim basis, pending appointment by the Board at the Board's earliest convenience, but will not otherwise act on the slate.

Board Approval

The Nominating Subcommittee will present the recommended committee membership slate to the Board for approval. If the Board approves the recommended committee slate, each member on the slate is appointed. The Board may also appoint members individually as needed to meet membership balance and fill vacancies.

Vacancies and Non-participation

The committee's secretary will administer the nominations process for vacancies on the committee.

Addressed on an Ongoing Basis

Vacancies on the committee can be addressed on an ongoing basis through receipt and consideration of both solicited and unsolicited nominations for the vacant positions.

Role of the Nominating Subcommittee

Nominations received for vacancies will be vetted by the Nominating Subcommittee in the same manner as general nominations. The subcommittee may subsequently and individually recommend nominees they deem qualified to the NERC Board for consideration for appointment to the committee. Existing committee members may also approve such individuals to serve as members on an interim basis pending full appointment by the Board.

Resignations

By the Member

In the event a member can no longer serve on the committee, that member will submit a written resignation to the committee chair or the secretary.

Requested by the Chair

The chair may request any committee member who ceases to participate in the committee, as indicated by not attending or sending a proxy for two consecutive meetings, to submit a resignation or to request continuation of membership with an explanation of extenuating circumstances. If a written response is not received within 30 days of the chair's request, the lack of response will be considered a resignation.

Referral to the Nominating Subcommittee

The committee chair will refer the vacancy resulting from a resignation to the Nominating Subcommittee of the committee. If a recent list of nominations is available to the Nominating Subcommittee that it deems to be valid, the subcommittee will recommend a replacement nominee; otherwise, the subcommittee will request NERC staff prepare a new solicitation for nominations to fill that position. The Nominating Subcommittee will follow the previously stated criteria in recommending a replacement.

By the Board

Committee members serve at the pleasure of the Board who may request resignation from, remove, or replace a member from the committee, as the Board deems appropriate.

Interim Approval

The committee chair may seek a vote of the committee to allow the proposed replacement member to be seated, pending appointment of the replacement at the Board's next scheduled meeting.

Proxies

A substitute representative, or proxy, may attend and vote during all or a portion of a committee meeting in lieu of a voting member provided the absent member notifies the committee chair, vice chair, or secretary of the proxy.

Notification

Such notification will be in writing (electronic medium is acceptable). The proxy representatives and their affiliation will be named in the correspondence.

Serving as Proxy

A voting member of a committee may not serve as a proxy for another voting member on the same committee (i.e. a member may not cast more than their own vote).

Exclusions

Regional Entity Staff

Regional Entity staff members who administer any portion of the Compliance and Enforcement program, Registration program, or Certification program for that Regional Entity, or for any other Regional Entity, may not serve as a member of the CCC.

Organizations

No two individuals from the same organization, or affiliated organizations, may serve concurrently on the committee. Any committee member who has a membership conflict of this nature is obligated to notify the committee secretary, who shall inform the committee chair. Members impacted by such a conflict, such as through a merger of organizations, may confer between themselves to determine which member should resign from the committee and notify the committee secretary and chair; however, if both members are within the same industry sector and cannot reach an amicable solution by determining the member to remain, the Nominating Subcommittee will review the qualifications of each member and propose the member to remain to the full committee who will determine which member shall continue to serve, subject to Board approval. If the conflict is not resolved in a timely manner by the impacted members, the committee chair shall notify all members of the

affected industry sectors recommending actions to resolve the conflict. If the membership conflict is still unresolved, the committee chair shall take the conflict to the NERC Board for resolution.

NERC Staff

The Director of Compliance Assurance shall not be a member of the committee or vote on committee business. The Director of Compliance Assurance and the secretary shall be recused from participating in any committee activity that involves monitoring of NERC's adherence to ROP or activity that the Director of Compliance Assurance oversees. If the NERC staff coordinator has been recused from participating in a Committee activity, the chair shall appoint another member of the committee as acting secretary for any meetings or other activities from which the NERC staff coordinator is recused.

Changes in Member Affiliation

A committee member whose affiliation has changed may retain the membership position under these circumstances:

1. The new organization is in the same industry sector, and
2. The member meets all other membership requirements.

Conflict of Interest

No committee member may have a conflict of interest that would impair his or her ability to fulfill obligations under this charter. Any committee member who knows of any form of membership conflict, such as working for an entity affiliated with that of another committee member, will notify the committee chair within 10 business days of obtaining that knowledge.

Meetings

In the absence of specific provisions in this manual, all committee meetings will follow Roberts Rules of Order.

Quorum

Two-thirds Requirement

The quorum necessary for transacting business at meetings of the committee is two-thirds of the voting members currently on the committee's roster.

Interim Basis

Voting members approved by the committee on an interim basis, pending appointment by the Board, will be counted in the determination of a quorum.

Lack of Quorum

If a quorum is not present at the beginning of the meeting, the committee may not take any actions requiring a vote by the committee; however, the chair may, with the consent of the members present, elect to allow discussion of the agenda items.

Voting

Actions by members of the committee will be approved upon receipt of the affirmative vote of two-thirds of the votes present (including proportional votes by Regional Representatives) at any meeting at which a quorum is present.

Antitrust Guidelines

All persons attending or otherwise participating in a NERC committee meeting will act in accordance with NERC's Antitrust Compliance Guidelines at all times during the meeting.

Open Meetings

NERC committee meetings will be open to the public, except as noted below under Confidential Information.

Confidential Sessions

At the discretion of the CCC chair, a meeting or portion of a meeting may have attendance limited based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive information or confidential information to one or more parties. All hearings of compliance matters will be confidential sessions. Confidential information will only be disclosed as provided by NERC ROP 1500. Confidentiality agreements may also be applied, as necessary, to protect sensitive information or confidential information.

Types of Meetings

Meetings may be conducted in person, by conference call, or by other means. The procedures contained in this manual will apply to all meetings regardless of how they are conducted.

Majority and Minority Views

All members of a committee will be given the opportunity to provide alternative views on an issue. The results of committee actions, including recorded minutes, will reflect the majority as well as any minority views of the committee members. The chair will communicate both the majority and any minority views in presenting results to the Board.

Action Without a Meeting

Two-thirds Majority

Any action required or permitted at a meeting of the committee may be taken without a meeting if two-thirds of the total votes available to the members of the CCC (including the proportional votes available to Regional Representatives) approve taking the action outside of a meeting.

Procedure

Such action without a meeting will be performed by mail or electronic ballot (e.g., telephone, fax, email, or Internet) and will be recorded in the minutes as a roll call ballot. The secretary will announce the action required at least 10 days before the date on which the action is to be voted. As time permits, members should be allowed a window of 10 business days to vote. The secretary will provide the results of such an action within 10 business days of the close of the voting period.

Officers and Staff

General

Number of Positions

The committee will have two officers and one secretary.

Officers

The committee officers will be one chair and one vice chair.

Executive

The committee shall retain an Executive Committee consisting of the committee officers, subcommittee chairs, secretary, and the Director of Compliance Assurance.

Secretary

The NERC staff coordinator will serve as the committee's secretary.

Voting of Officers

The committee chair and vice chair are voting members of the committee.

Officers Nominated by the Nominating Subcommittee

The CCC Nominating Subcommittee will recommend a chair and a vice chair who are then appointed by the NERC Board for a two-year term. The term of the chair and the vice chair, except for the first year, will begin on July 1 and end on June 30.

Officers as Sector Representatives

The chair and vice chair are selected from the membership of the committee and, in addition to their chair or vice chair responsibilities, will continue to serve as a member for the sector for which they were appointed to the committee.

Chair

The chair will direct and provide general supervision of committee activities, including the following:

1. Coordinate the schedule of all committee meetings, including approval of meeting duration and location;
2. Develop committee agendas and rule on any deviation, addition, or deletion from a published agenda;
3. Preside at and manage committee meetings, including the nature and length of discussion, recognition of speakers and proxies, motions, and voting;
4. Will lead or direct the conduct of any hearings and the preparation of any adjudicatory documents by the committee under Section 408 of the NERC ROP;
5. Will ensure actions and undertakings by the committee under the NERC ROP Section 408 meet all applicable legal and due process requirements;
6. Will act as spokesperson for the committee at forums inside and outside of NERC; and
7. May attend meetings of the NERC Board when necessary to report to the Board on committee activities.

Vice Chair

The vice chair will assume the responsibilities of the chair under the following conditions:

1. At the discretion of the chair (for brief periods of time);

2. When the chair is absent or temporarily unable to perform the chair's duties; or
3. When the chair is permanently unavailable or unable to perform the chair's duties. In the case of a permanent change, the vice chair will continue to serve until a new chair is nominated and selected by the Board.

Staff Coordinator

A member of the NERC staff will be selected by NERC's Director of Compliance Assurance to serve as the staff coordinator and secretary of the committee. The staff coordinator is not a committee member and does not have a vote. Under the direction of the committee executive and applicable NERC bylaws, guidelines, and ROP, the staff coordinator will do the following:

1. Manage the day-to-day operation and business of the committee;
2. Prepare and distribute the notices of the committee meetings, prepare the meeting agenda, and prepare and distribute the minutes of the committee meetings; and
3. Act as the committee's parliamentarian.

Nominating Subcommittee

Appointment

The CCC will annually appoint a Nominating Subcommittee.

Five Members

The subcommittee will consist of five members nominated by the committee chair and approved by the committee. The chair of the subcommittee will be selected by the CCC chair from among the five subcommittee members.

Appointed Annually

The chair will appoint the subcommittee members at the first regular meeting of the committee of the calendar year.

Length of term

The subcommittee members will serve for up to 14 months or until a new Nominating Subcommittee is authorized, whichever is earlier.

Duties

In addition to the duties, rights, and privileges described elsewhere in this manual, members of the Nominating Subcommittee will:

1. Prepare a slate of committee officer candidates for submission to the NERC Board for approval, and
2. Prepare a slate of recommended individuals to fill designated committee vacancies as required.

Subordinate Groups

Committee Organization

The CCC organizational structure will be arranged as allowed in the NERC Bylaws to support a superior-subordinate hierarchy that is ordered as follows: a committee, a subcommittee, a working group, and a task force, with a committee being primary and a task force being quaternary.

Subgroups

The committee may establish subcommittees, working groups, and task forces as necessary. The committee chair may also form any of these subordinate groups on behalf of the committee. The committee will be the responsible sponsor of all subordinate subcommittees, working groups, or task forces it may create, or that its subordinate subcommittees and working groups may create. The committee will keep the Board informed of all groups subordinate to the committee.

Subcommittees

The committee may establish subcommittees to which the committee may delegate some of the committee's broadly defined continuing functions. The committee will approve the scope of each subcommittee it forms. The committee chair will appoint the subcommittee officers (typically a chair and a vice chair) for a specific term (generally two years). The subcommittee officers may be reappointed for up to two additional terms. The subcommittee will work within its assigned scope and be accountable for the responsibilities assigned to it by the committee. The formation of a subcommittee, due to the permanency of the subcommittee, will be approved by the Board.

Working Groups

The committee or any of its subcommittees may delegate specific continuing functions to a working group. The sponsoring committee or subcommittee will approve the scope of each working group it forms. The chair of the sponsoring committee or subcommittee will appoint the working group officers (typically a chair and a vice chair) for a specific term (generally two years). The working group officers may be reappointed for up to two additional terms. The sponsoring committee or subcommittee will conduct a "sunset" review of each working group every two years. The working group will be accountable for the responsibilities assigned to it by the committee or subcommittee and will, at all times, work within its assigned scope.

Task Forces

The committee, subcommittee, or working group may assign specific work of a finite duration to a task force. The sponsoring committee, subcommittee, or working group will approve the scope of each task force it forms. The chair of the sponsoring committee, subcommittee, or working group will appoint the task force officers (typically a chair and a vice chair). Each task force will have a finite duration, normally less than one year. The sponsoring group will review the task force scope at the end of the expected duration and at each subsequent meeting of the sponsoring group after that until the task force is retired. Action of the task force sponsoring group is required to continue the task force past its defined duration. The sponsoring group should consider promoting to a working group any task force that is required to work longer than one year.

Membership and Representation

The membership of each subcommittee, working group, and task force should be established to address the need for expertise and balance of interests. Each group's membership requirements will be defined within the group's approved scope.

As a general guide, the broader the group's scope, the more emphasis there should be on balancing of interests. Therefore, subcommittees would be expected to have the broadest representation of appropriate industry

sectors, while a task force may be more focused on simply having the necessary expertise, and a working group may be somewhere between.

Each member of a subordinate group, and its officers, will be appointed by the chair of the sponsoring committee or group.

To the extent subgroup membership is of a representative nature, recommendations for staffing of the group should be provided in a manner consistent with the principles outlined in the staffing of a committee, including the use of an open nominations process. Regional Entity representatives should be recommended by the Regional Entity and Canadian representatives by the Canadian Electricity Association.

Preference may also be given to representatives recommended by broadly-based industry associations.

To the extent that subgroup membership is based on providing requisite expertise, the chair of the sponsoring committee or group may appoint members based on the relevant technical qualifications.

Procedures

Subcommittees, working groups, and taskforces will conduct business in a manner consistent with all applicable sections of this manual and Robert's Rules of Order.

Hearings

General

The CCC will conduct hearings, as necessary, to fulfill its function of serving as the hearing body for any contest between NERC and a Regional Entity regarding NERC findings, penalties, or sanctions for violation(s) of Reliability Standard(s) by the Regional Entity as described in Section 408 of the NERC ROP.

Hearing Procedure

Unless specifically identified otherwise elsewhere in this charter, the CCC's hearing procedure shall follow the hearing procedure mandated and approved by jurisdictional authorities for use by NERC and the Regional Entities in the Compliance and Enforcement program.

Hearing Panel

The committee shall not have a standing hearing panel. When a hearing is to be conducted, the CCC shall select five members to serve as the adjudicatory panel for that hearing. Members to serve on the panel shall be selected by vote of a valid quorum of the committee. Voting members of the committee at arm's length from parties to the hearing may be nominated or volunteer to stand for selection to the hearing panel. One or more alternates may also be selected, as the committee deems appropriate for the circumstances. A member may serve on more than one panel concurrently. A panel is disbanded upon conclusion of the hearing proceedings for which it was formed.

Attachment A

CCC Membership Structure

Primary Sector	Sub-Sector	Number of Members	Full Voting	Proportional Voting	Non-Voting
Investor-Owned Utility		2	X		
State/Municipal Utility		2	X		
Cooperative Utility		2	X		
Federal or Provincial Utility/Federal Power Marketing Administration		2	X		
Transmission Dependent Utility		2	X		
Merchant Electricity Generator		2	X		
Electricity Marketer		2	X		
Large End-use Electricity Customer		2	X		
Small End-use Electricity Customer		2	X		
Independent System Operator/Regional Transmission Organization		2	X		
Regional Entity	FRCC	1		X	
	RFC	1		X	
	ERCOT	1		X	
	MRO	1		X	
	NPCC	1		X	
	SERC	1		X	
	SPP	1		X	
	WECC	1		X	
Government	U.S. State	2	X		
	U.S. Federal	2			X
	Canadian Provincial	1			X
	Canadian Federal	1			X
Total		**34**			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

May 30, 2018

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

RE: Errata to Implementation Plan for the Revised Definition of Remedial Action Scheme
Docket No. RM15-13-_

Dear Ms. Bose:

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC") requests approval of an errata to the Implementation Plan for the Revised Definition of "Remedial Action Scheme" (the "RAS Implementation Plan"). The errata is necessary to incorporate into the RAS Implementation Plan certain necessary implementation provisions from the Implementation Plan associated with Reliability Standard PRC-023-3 (the "PRC-023-3 Implementation Plan") that were inadvertently omitted from the RAS Implementation Plan and previous errata to that implementation plan.

As background, on February 3, 2015, NERC filed a petition for approval of proposed revisions to the definition of the term "Remedial Action Scheme" ("RAS") in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") and modifications to specified Reliability Standards to incorporate the revised RAS definition.[3] Among others, the PRC-023 Reliability Standard was modified to incorporate the RAS definition, moving from version PRC-023-3 to PRC-023-4. There were no other substantive changes made to the Reliability Standard at that time. In Order No. 818, the Commission approved the revised RAS definition and modifications to the Reliability Standards.[4]

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1 16 U.S.C. § 824o (2006).
2 18 C.F.R. § 39.5 (2018).
3 *Petition of the North American Electric Reliability Corporation for Approval of Revisions to the Definition of "Remedial Action Scheme" and Proposed Reliability Standards*, Docket No. RM15-13-000 (Feb. 3, 2015).
4 Order No. 818, *Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards*; *Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, 80 Fed. Reg. 73,647 (Nov. 25, 2015).

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Certain provisions from the PRC-023-3 Implementation Plan, however, were inadvertently omitted from the RAS Implementation Plan. Specifically, the PRC-023-3 Implementation Plan included specific provisions for load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6. The provisions allow applicable Registered Entities to comply with Requirements R1, R2, and R3 for those systems the latter of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date. Additionally, the PRC-023-3 Implementation Plan included provisions regarding the retirement of Requirement R1, Criterion 6, contained in PRC-023-2. Specifically, the PRC-023-3 Implementation Plan specified that Requirement R1, Criterion 6 remains in effect through the implementation of Reliability Standard PRC-025-1. In order to ensure that the specified provisions carried forward to the PRC-023-4 version of the Reliability Standard, NERC submitted an errata to the RAS Implementation plan to incorporate those provisions in the RAS Implementation Plan, which the Commission approved on December 15, 2017.[5]

The previously filed errata to the RAS Implementation Plan, however, inadvertently omitted the application of the 39-month period to Requirement R1. This provision must be carried forward for the PRC-023-4 version of the Reliability Standard to ensure that entities continue to have the appropriate implementation period for complying with requirements applicable to load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6. As a result, NERC submits a second errata to the RAS Implementation Plan. A clean version of the revised RAS Implementation Plan is provided as **Exhibit A** hereto. A redline version of the revised RAS Implementation Plan is provided in **Exhibit B**.

For the reasons set forth above, NERC respectfully requests that the Commission approve the proposed errata to the RAS Implementation Plan.

Respectfully submitted,

/s/ Shamai Elstein

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[5] *North American Electric Reliability Corporation*, Letter Order, Docket No. RM15-13-001 (Dec. 15, 2017).

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 30th day of May, 2018.

/s/ Shamai Elstein

Shamai Elstein

Counsel for the North American Electric Reliability Corporation

EXHIBIT A

Revised Definition of “Remedial Action Scheme” (RAS) Implementation Plan – Clean Version

Implementation Plan for the Revised Definition of "Remedial Action Scheme"

Project 2010-05.2 – Special Protection Systems

Background

The existing Glossary of Terms Used in NERC Reliability Standards definition for "Special Protection System" ("SPS") or "Remedial Action Scheme" ("RAS") lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS/RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS/RAS. The actions listed in the definition of SPS, which are incorporated by cross reference (NERC Glossary of Terms) into the definition of RAS, are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term, i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

The Project 2010-05.2 SPS SDT coordinated the development of the RAS definition with the development of PRC-010-1 by the SDT for Project 2008-02 – Undervoltage Load Shedding. The UVLS SDT introduced a new term, UVLS Program, into the Glossary of Terms Used in NERC Reliability Standards to clearly establish applicability of PRC-010-1. The proposed term UVLS Program is defined as: "An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included."

Note that the proposed definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, should be subject to RAS-related Reliability Standards. The Project 2010-05.2 SPS SDT agreed with this assessment and revised the definition of RAS to clarify that it is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as RAS. The coordination of these revisions is required to maintain coverage of those systems and prevent a reliability gap. As a

result of these revisions, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective dates of the revised definitions of RAS and UVLS Program.

Requested Approvals

The definition of "**Remedial Action Scheme**" and the standards are listed below:

The following standards are proposed for approval to align the use of the single defined term RAS. This list is intended to reflect Reliability Standards currently in effect at the time of Project development. In certain cases, a standard listed below for approval may already be retired pursuant to an implementation plan of a successor version by the time the definition of "Remedial Action Scheme" becomes effective in a particular jurisdiction. In these cases, the standard below will not become effective.

CIP-002-3(i)	PRC-004-WECC-2	PRC-020-2
CIP-002-3(i)b	PRC-005-2(ii)	PRC-021-2
EOP-004-3	PRC-005-3(ii)	PRC-023-2(i)
FAC-010-3	PRC-006-1(i)	PRC-023-4[1]
FAC-011-3	PRC-012-1	TOP-005-3a
IRO-005-3.1(i)a	PRC-013-1	TPL-001-0.1(i)
MOD-029-2a	PRC-014-1	TPL-002-0(i)b
MOD-030-3	PRC-015-1	TPL-003-0(i)b
NUC-001-2.1(i)	PRC-016-1	TPL-004-0(i)a
PRC-001-1.1(i)	PRC-017-1	

Requested Retirements

CIP-002-3	PRC-004-WECC-1	PRC-020-1
CIP-002-3b	PRC-005-2	PRC-021-1
EOP-004-2	PRC-005-3	PRC-023-2
FAC-010-2.1	PRC-006-1	PRC-023-3
FAC-011-2	PRC-012-0	TOP-005-2a
IRO-005-3.1a	PRC-013-0	TPL-001-0.1
MOD-029-1a	PRC-014-0	TPL-002-0b
MOD-030-02	PRC-015-0	TPL-003-0b
NUC-001-2.1	PRC-016-0.1	TPL-004-0a
PRC-001-1.1	PRC-017-0	

[1] This Implementation Plan carries forward and incorporates by reference the following two provisions set forth in the Implementation Plan associated with Reliability Standard PRC-023-3 that are specific to load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6: (1) Each Transmission Owner, Generator Owner, and Distribution Provider in Requirements R1, R2 and R3 shall become compliant the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date; and (2) Requirement R1, Criterion 6 of PRC-023-2 shall remain in force until the effective date of PRC-025-1.

General Considerations

The entity shall modify its processes as necessary to account for the revised definition. The revised definition of RAS clarifies that it is inclusive of centrally controlled undervoltage-based load shedding. Entities may have additional changes to the classification of certain schemes to align them with the revised definition.

This Implementation Plan provides additional time for entities with newly classified RAS to become compliant with the Reliability Standards during the transition to the revised definition.

All aspects of the Implementation Plans for PRC-005-2 and PRC-005-3 will remain applicable to PRC-005-2(ii) and PRC-005-3(ii). These implementation plans are incorporated here by reference.

Prerequisite Approvals

NERC Reliability Standard PRC-010-1 – Undervoltage Load Shedding
Definition of "Undervoltage Load Shedding Program (UVLS Program)" in Project 2008-02 Undervoltage Load Shedding

Revisions to the NERC Glossary of Terms

The drafting team proposes the following revised definition:

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

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

The following do not individually constitute a RAS:

a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements

b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays

c. Out-of-step tripping and power swing blocking

d. Automatic reclosing schemes

e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service

f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated

g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device

h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched

i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open

j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

k. Automatic sequences that proceed when manually initiated solely by a System Operator

l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations

m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)

n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g., automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

Conforming Changes to Other Standards

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document *Revised Reliability Standards for the Revised Definition of "Remedial Action Scheme."*

Effective Date for Revised Reliability Standards and Definition

Except as noted below, the revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are 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 standards and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Newly Classified Remedial Action Schemes (RAS)

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.

Retirement of Existing Standards and Definitions

The requested Reliability Standards for retirement shall be retired at midnight of the day immediately prior to the Effective Date of its successor standard in the particular jurisdiction in which the revised definition is becoming effective. The current definition of "Remedial Action Scheme" shall be retired at midnight of the day immediately prior to the Effective Date of the revised definition of "Remedial Action Scheme".

EXHIBIT B

Revised Definition of “Remedial Action Scheme” (RAS) Implementation Plan – Redline Version

Implementation Plan for the Revised Definition of "Remedial Action Scheme"

Project 2010-05.2 – Special Protection Systems

Background

The existing Glossary of Terms Used in NERC Reliability Standards definition for "Special Protection System" ("SPS") or "Remedial Action Scheme" ("RAS") lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS/RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS/RAS. The actions listed in the definition of SPS, which are incorporated by cross reference (NERC Glossary of Terms) into the definition of RAS, are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term, i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

The Project 2010-05.2 SPS SDT coordinated the development of the RAS definition with the development of PRC-010-1 by the SDT for Project 2008-02 – Undervoltage Load Shedding. The UVLS SDT introduced a new term, UVLS Program, into the Glossary of Terms Used in NERC Reliability Standards to clearly establish applicability of PRC-010-1. The proposed term UVLS Program is defined as: "An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included."

Note that the proposed definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, should be subject to RAS-related Reliability Standards. The Project 2010-05.2 SPS SDT agreed with this assessment and revised the definition of RAS to clarify that it is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as RAS. The coordination of these revisions is required to maintain coverage of those systems and prevent a reliability gap. As a

result of these revisions, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective dates of the revised definitions of RAS and UVLS Program.

Requested Approvals

The definition of "**Remedial Action Scheme**" and the standards are listed below:

The following standards are proposed for approval to align the use of the single defined term RAS. This list is intended to reflect Reliability Standards currently in effect at the time of Project development. In certain cases, a standard listed below for approval may already be retired pursuant to an implementation plan of a successor version by the time the definition of "Remedial Action Scheme" becomes effective in a particular jurisdiction. In these cases, the standard below will not become effective.

CIP-002-3(i)	PRC-004-WECC-2	PRC-020-2
CIP-002-3(i)b	PRC-005-2(ii)	PRC-021-2
EOP-004-3	PRC-005-3(ii)	PRC-023-2(i)
FAC-010-3	PRC-006-1(i)	PRC-023-4[1]
FAC-011-3	PRC-012-1	TOP-005-3a
IRO-005-3.1(i)a	PRC-013-1	TPL-001-0.1(i)
MOD-029-2a	PRC-014-1	TPL-002-0(i)b
MOD-030-3	PRC-015-1	TPL-003-0(i)b
NUC-001-2.1(i)	PRC-016-1	TPL-004-0(i)a
PRC-001-1.1(i)	PRC-017-1	

Requested Retirements

CIP-002-3	PRC-004-WECC-1	PRC-020-1
CIP-002-3b	PRC-005-2	PRC-021-1
EOP-004-2	PRC-005-3	PRC-023-2
FAC-010-2.1	PRC-006-1	PRC-023-3
FAC-011-2	PRC-012-0	TOP-005-2a
IRO-005-3.1a	PRC-013-0	TPL-001-0.1
MOD-029-1a	PRC-014-0	TPL-002-0b
MOD-030-02	PRC-015-0	TPL-003-0b
NUC-001-2.1	PRC-016-0.1	TPL-004-0a
PRC-001-1.1	PRC-017-0	

[1] This Implementation Plan carries forward and incorporates by reference the following two provisions set forth in the Implementation Plan associated with Reliability Standard PRC-023-3 that are specific to load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6: (1) Each Transmission Owner, Generator Owner, and Distribution Provider in Requirements R1, R2 and R3 shall become compliant the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date; and (2) Requirement R1, Criterion 6 of PRC-023-2 shall remain in force until the effective date of PRC-025-1.

General Considerations

The entity shall modify its processes as necessary to account for the revised definition. The revised definition of RAS clarifies that it is inclusive of centrally controlled undervoltage-based load shedding. Entities may have additional changes to the classification of certain schemes to align them with the revised definition.

This Implementation Plan provides additional time for entities with newly classified RAS to become compliant with the Reliability Standards during the transition to the revised definition.

All aspects of the Implementation Plans for PRC-005-2 and PRC-005-3 will remain applicable to PRC-005-2(ii) and PRC-005-3(ii). These implementation plans are incorporated here by reference.

Prerequisite Approvals

NERC Reliability Standard PRC-010-1 – Undervoltage Load Shedding
Definition of "Undervoltage Load Shedding Program (UVLS Program)" in Project 2008-02 Undervoltage Load Shedding

Revisions to the NERC Glossary of Terms

The drafting team proposes the following revised definition:

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

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

The following do not individually constitute a RAS:

a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements

b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays

c. Out-of-step tripping and power swing blocking

d. Automatic reclosing schemes

e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service

f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated

g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device

h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched

i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open

j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

k. Automatic sequences that proceed when manually initiated solely by a System Operator

l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations

m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)

n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g., automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

Conforming Changes to Other Standards

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document *Revised Reliability Standards for the Revised Definition of "Remedial Action Scheme."*

Effective Date for Revised Reliability Standards and Definition

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Implementation Plan for Newly Classified Remedial Action Schemes (RAS)

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.

Retirement of Existing Standards and Definitions

The requested Reliability Standards for retirement shall be retired at midnight of the day immediately prior to the Effective Date of its successor standard in the particular jurisdiction in which the revised definition is becoming effective. The current definition of "Remedial Action Scheme" shall be retired at midnight of the day immediately prior to the Effective Date of the revised definition of "Remedial Action Scheme".

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. FA11-21-000**

COMPLIANCE FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] submits this compliance filing in accordance with the Commission's January 16, 2013 Order in Docket No. FA11-21-000.[2] In the January 16 Order, the Commission approved a Settlement Agreement between the Office of Enforcement ("Enforcement") and NERC related to Enforcement's findings and recommendations arising out of its 2012 performance audit of NERC. Specifically, Section II.7(b)(i) of the Settlement Agreement requires that:

> Within forty-five days of the end of each quarter, beginning with the quarter ending March 31, 2013, NERC will file with the Commission the unaudited report of the NERC budget-to-actual spending variances during the preceding quarter. This report will include information regarding sources and uses of operating and working capital reserves and will match or exceed the level of detail of the quarterly budget-to-actual variance report of NERC expenditures attached to the agenda of NERC Board of Trustees Finance and Audit Committee's October 2012 meeting.[3]

Attached hereto is the unaudited report of NERC's budget-to-actual variance information for the first quarter of 2018, in accordance with the January 16 Order. This variance information

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[1] NERC was certified by FERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

[2] *See North American Electric Reliability Corporation, Order Approving Settlement Agreement*, 142 FERC ¶ 61,042 (2013) ("January 16 Order").

[3] *Id.*

was posted on NERC's website May 3, 2018 and reviewed at the May 9, 2018 open meeting of the NERC Finance and Audit Committee. The unaudited report was accepted by the NERC Board of Trustees at its meeting on May 10, 2018.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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III. DISCUSSION OF SIGNIFICANT VARIANCES BETWEEN 2018 BUDGET AND ACTUAL PROJECTED 2018 RESULTS

The attached first quarter 2018 variance report compares actual (unaudited) financial results to NERC's budgeted expenditures as of March 31, 2018, and projected year-end 2018 financial results to NERC's total 2018 budgeted expenditures. NERC is providing additional discussion of significant variances between the projected (unaudited) year-end 2018 results and NERC's 2018 budgeted expenditures, by NERC department or program area and by major activity within departments and program areas. This discussion focuses on variances of $500,000 or more between projected year-end 2018 results and the 2018 budget. For purposes of this discussion, NERC has focused on projected year-end variances in excess of budget of $500,000 or more, because Section 7(b)(ii) of the Settlement Agreement specifies that NERC will file for Commission review and approval proposals approved by the NERC Board of Trustees to expend

$500,000 or more from Operating Reserves designated for "unforeseen contingencies" (as defined in NERC's Working Capital and Operating Reserves Policy), *i.e.*, where any amount allocated from the unforeseen contingencies account of Operating Reserves plus any amount redirected from previously budgeted funds is, in the aggregate, $500,000 or more for any one specific project or major activity in a program area.

A. Information Technology

Actual 2018 direct expenses plus net fixed asset expenditures for the Information Technology department are projected to be $500k over budget, due in large part to the unanticipated costs of the SPP RE transition work, specifically related to the transfer of systems and data between Regional Entities. In addition, the department is expected to be slightly over budget in personnel, software maintenance and license costs.

IV. CONCLUSION

NERC respectfully requests that the Commission accept this filing as compliant with Section II.7(b)(i) of the Settlement Agreement and the Commission's January 16 Order in Docket No. FA11-21-000.

Respectfully submitted,

/s/ Meredith M. Jolivert

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Counsel for North American Electric Reliability Corporation

Dated: May 15, 2018

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 15th day of May, 2018.

/s/ Meredith M. Jolivert

Meredith M. Jolivert
Counsel for North American Electric Reliability Corporation

ATTACHMENT

Summary of Unaudited Results
For the Month Ending March 31, 2018

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Executive Summary

Projected Year-End Results
($ millions)

FUNDING	Projected	Budget	Over (Under)
Revenues	$ 72.4	$ 72.4	$ -
Funding from Reserves			
Assessment Stabilization Reserve	0.6	0.6	-
TOTAL FUNDING	**$ 73.0**	**$ 73.0**	**$ -**
EXPENDITURES			
Expenses (excluding Depreciation)	$ 69.9	$ 69.3	$ 0.6
Fixed Asset Additions	3.9	3.9	-
TOTAL EXPENDITURES	**$ 73.8**	**$ 73.2**	**$ 0.6**
RESERVE INCREASE (DECREASE)	**$ (0.8)**	**$ (0.2)**	**$ (0.6)**

FUNDING

- Revenues
  - Projected to be on budget
- Funding from Reserves
  - No reserve funding expected other than the budgeted amount from the Assessment Stabilization Reserve

EXPENDITURES

- Expenses
  - Personnel expenses expected to be over budget because of increased medical insurance, retirement, and executive search fee costs
  - Contracts and consultants projected to be over budget primarily due to costs for SPP RE transition work and a cyber-security supply chain risk study
- Fixed Assets
  - Expected to be on budget

RESERVE INCREASE (DECREASE)

- Projected decrease in total reserves is greater than budget by $0.6M

Year-to-Date Actual Results
($ millions)

FUNDING	Actual	Budget	Over (Under)
Revenues	$ 18.0	$ 18.1	$ (0.1)
Funding from Reserves			
Assessment Stabilization Reserve	0.6	0.6	-
TOTAL FUNDING	**$ 18.6**	**$ 18.7**	**$ (0.1)**
EXPENDITURES			
Expenses (excluding Depreciation)	$ 17.3	$ 18.2	$ (0.9)
Fixed Asset Additions	0.1	1.0	(0.9)
TOTAL EXPENDITURES	**$ 17.4**	**$ 19.2**	**$ (1.8)**
RESERVE INCREASE (DECREASE)	**$ 1.2**	**$ (0.5)**	**$ 1.7**

FUNDING

- Revenues
  - Testing fees and workshop fees slightly below budget

EXPENDITURES

- Expenses
  - Meetings, Contracts and Consultants, and Office Costs are under budget due to the expected timing of expenditures versus budget
- Fixed Assets
  - Project expenditures are under budget because of the expected timing of expenditures versus budget

OPERATING RESERVE INCREASE (DECREASE)

- Reserve increase higher than budget by $1.7 million
  - Additional net increase of reserves from operating results, primarily due to the expected timing of expenditures versus budget

Detailed Operating Results

Total NERC (including CRISP)

Variances by Revenue and Expense Category

	YTD Actual	YTD Budget	YTD Over (Under)	% Inc (Dec)	Annual Projection	Annual Budget	Annual Over (Under)	% Inc (Dec)
TOTAL FUNDING	**$ 18,623,957**	**$ 18,714,055**	**$ (90,098)**	**(0.5%)**	**$ 73,018,216**	**$ 72,981,221**	**$ 36,995**	**0.1%**
EXPENDITURES								
Personnel	$ 10,853,675	$ 10,810,451	$ 43,224	0.4%	$ 41,450,947	$ 40,969,105	$ 481,842	1.2%
Meetings, Travel, and Conference Calls	645,006	866,900	(221,894)	(25.6%)	3,331,353	3,395,100	(63,747)	(1.9%)
Contracts and Consultants	3,243,623	3,733,003	(489,380)	(13.1%)	14,096,841	13,724,185	372,656	2.7%
Rent and Facilities	749,745	772,951	(23,206)	(3.0%)	3,087,919	3,091,804	(3,885)	(0.1%)
Office Costs, Professional, and Misc.*	1,757,032	1,994,198	(237,166)	(11.9%)	7,821,916	7,942,084	(120,167)	(1.5%)
Other Non-Operating Expenses	8,704	34,720	(26,015)	(74.9%)	138,878	138,878	-	0.0%
Fixed Asset Additions *	149,097	968,500	(819,403)	(84.6%)	3,874,000	3,874,000	-	0.0%
TOTAL EXPENDITURES	**$ 17,406,882**	**$ 19,180,722**	**$ (1,773,840)**	**(9.2%)**	**$ 73,801,855**	**$ 73,135,156**	**$ 666,699**	**0.9%**
RESERVE INCREASE (DECREASE)	**$ 1,217,075**	**$ (466,667)**	**$ 1,683,742**	**(360.8%)**	**$ (783,639)**	**$ (153,935)**	**$ (629,704)**	**409.1%**
FTEs	**192.9**	**199.3**	**(6.4)**	**(3.2%)**	**191.3**	**199.3**	**(8.0)**	**(4.0%)**

***** Excluding depreciation

Following is a brief summary of variances by major categories:

- Personnel Expense
  - On-budget year-to-date
  - Expected to be over budget at year-end because of increased medical insurance, retirement, and executive search fee costs

- Meetings, Travel, and Conference Calls Expense
  - Under budget year-to-date due to the expected timing of expenditures versus budget
  - Expected to be near budget at year-end

- Contracts and Consultants Expense
  - Under budget year-to-date because of the expected timing of expenditures versus budget
  - Projected to be over budget at year-end primarily due to SPP RE transition costs and an unplanned cyber-security supply chain risk EPRI project

CONTRACTS and CONSULTANTS	YTD Actual	YTD Budget	YTD Over (Under)	Annual Projection	Annual Budget	Annual Over (Under)
Reliability Standards	$ -	$ -	$ -	$ 100,000	$ -	$ 100,000
Compliance Assurance	-	12,500	(12,500)	50,000	50,000	-
Compliance Analysis, Registration and Certification	28,670	-	28,670	49,950	-	49,950
Compliance Enforcement	-	-	-	-	-	-
Reliability Assessment and System Analysis	30,500	131,250	(100,750)	525,000	525,000	-
Reliability Risk Management	754,621	841,338	(86,717)	1,867,525	1,867,525	-
E-ISAC	297,254	275,050	22,204	1,100,200	1,100,200	-
Training, Education, and Personnel Certification	77,610	149,725	(72,115)	598,900	598,900	-
General and Administrative and Executive	-	-	-	80,000	80,000	-
Legal and Regulatory	-	-	-	-	-	-
Policy and External Affairs	-	6,250	(6,250)	41,500	20,000	21,500
Information Technology	425,059	530,992	(105,933)	2,325,172	2,123,966	201,206
Human Resources	54,797	106,250	(51,453)	640,000	640,000	-
Finance and Accounting	33,606	106,750	(73,144)	427,000	427,000	-
TOTAL (excluding CRISP)	**$ 1,702,116**	**$ 2,160,104**	**$ (457,988)**	**$ 7,805,247**	**$ 7,432,591**	**$ 372,656**
CRISP	1,541,506	1,572,899	(31,392)	6,291,594	6,291,594	-
TOTAL (including CRISP)	**$ 3,243,623**	**$ 3,733,003**	**$ (489,380)**	**$ 14,096,841**	**$ 13,724,185**	**$ 372,656**

- Office Costs and Professional Fees
  - Under budget year-to-date because of the expected timing of expenditures versus budget
  - Projected to be near budget at year-end

- Fixed Asset Additions (excluding depreciation)
  - Under budget year-to-date because of the expected timing of expenditures versus budget
  - Projected to be near budget at year-end

Variances by Department / Program

DIRECT EXPENSES and NET FIXED ASSETS	YTD Actual	YTD Budget	YTD Over (Under)	Annual Projection	Annual Budget	Annual Over (Under)
Reliability Standards	$ 681,104	$ 876,532	$ (195,428)	$ 2,894,287	$ 3,293,666	$ (399,378)
Compliance Assurance	1,248,172	1,147,842	100,330	4,647,111	4,520,550	126,561
Compliance Analysis, Registration and Certification	703,527	712,075	(8,548)	2,906,759	2,748,762	157,996
Compliance Enforcement	733,125	1,009,370	(276,245)	4,084,925	3,894,123	190,802
Reliability Assessment and System Analysis	1,046,751	1,087,851	(41,101)	4,362,443	4,105,476	256,967
Reliability Risk Management	2,203,586	2,359,501	(155,914)	7,516,969	7,654,264	(137,296)
E-ISAC	1,521,768	1,891,010	(369,242)	7,167,371	7,357,222	(189,851)
Training, Education, and Personnel Certification	370,588	432,631	(62,043)	1,726,311	1,706,574	19,737
General and Administrative and Executive	1,854,166	2,007,330	(153,164)	7,688,441	7,874,321	(185,880)
Legal and Regulatory	738,418	770,440	(32,022)	3,035,046	2,914,377	120,669
Policy and External Affairs	613,284	593,833	19,451	2,327,338	2,221,826	105,512
Information Technology	2,588,767	2,881,570	(292,803)	11,766,931	11,266,626	500,305
Human Resources	301,570	385,378	(83,808)	1,682,659	1,704,459	(21,799)
Finance and Accounting	1,019,538	1,043,941	(24,403)	4,227,342	4,008,326	219,016
TOTAL (excluding CRISP)	**$ 15,624,364**	**$ 17,199,306**	**$ (1,574,941)**	**$ 66,033,932**	**$ 65,270,572**	**$ 763,360**
CRISP	1,782,517	1,981,416	(198,899)	7,767,923	7,864,584	(96,661)
TOTAL EXPENSES and NET FIXED ASSETS	**$ 17,406,882**	**$ 19,180,722**	**$ (1,773,840)**	**$ 73,801,855**	**$ 73,135,156**	**$ 666,699**

- Reliability Standards: Projected to be under budget primarily because of reduced personnel costs resulting from the reallocation of resources to other departments.

- Reliability Assessments and System Analysis: Projected to be over budget because of increased personnel costs related to the reallocation of resources from other departments.

- Information Technology: Projected to be over budget due to largely to the unanticipated costs of the SPP RE transition, particularly related to the transfer of systems and data between regional entities. Additionally, the department is expected to be slightly over budget in personnel and software maintenance/license costs.

SUPPLEMENTAL SCHEDULE 1

Year-End Projected Reserves

Reserve Account	Beginning Balance [2]	Budgeted Funding	Budgeted Uses	Other Funding (Uses) [1]	Net Financing Activity [3]	Expected Ending Balance
Operating Contingency	**$ 3,680,094**	$ 600,000	$ (231,393)	$ (1,185,147)	$ 714,726	**$ 3,578,280**
Future Obligations	**3,015,787**	-	(480,457)	(15,759)	-	**2,519,571**
Assessment Stabilization	**2,671,000**	-	(600,000)	-	-	**2,071,000**
System Operator	**477,484**	77,458	-	(44,556)	-	**510,386**
CRISP	**500,000**	-	-	-	-	**500,000**
Total Reserves	**$ 10,344,365**	$ 677,458	$ (1,311,850)	$ (1,245,463)	$ 714,726	**$ 9,179,237**

NOTES:

(1) The column Other Funding (Uses) primarily reflects the net impact of normal operations. For example, under normal circumstances, if NERC was tracking well under budget in actual expenditures, this would reflect additional funds into the reserve account.

(2) Some 2018 beginning balances have been adjusted from the 12/31/2017 variance report balances as the result of a reconciliation to the final audited balance sheet.

(3) Net Financing Activity is projected to be favorable to budget by $483k due to lower debt service requirements in 2018, primarily as a result of no capital borrowing in 2017.

SUPPLEMENTAL SCHEDULE 2

IT Projects
Actuals Through March 2018

Projects in Progress	Project Budget [1]	Actual Spend	Expected Spend	Expected Over (Under) Budget
CMEP Program	$ 5,103,000	$ 288,000	$ 5,103,000	$ -
E-ISAC Portal Enhancements	403,975	308,791	403,975	-
E-ISAC Document Management	215,000	-	215,000	-
Entity Registration - CORES (Discovery) and JRO (On Hold)	600,000	138,539	187,989	(412,011)
SPP RE Transition	-	-	201,206	201,206

Projects Completed in 2018	Project Budget [1]	Actual Spend	Actual Over (Under) Budget
NERC.com Phase 2	$ 300,000	$ 217,100	$ (82,900)

NOTES:

(1) The Project Budget noted above usually corresponds to the approved business case for each project and funds for each project are drawn from the available budget. In some projects, business cases may not be prepared, particularly when a project is smaller and/or may be in response to a FERC order.

** Some of these projects span multiple years, so the amounts above do not represent a single budget year expenditure.*

** The amounts noted above do not include internal labor and reflect only external (consultant) costs of the projects.*

SUPPLEMENTAL SCHEDULE 2
(continued)

CMEP Program
(Started May 2017 / Planned Completion Dec 2020)
This project will provide registered entities, Regional Entities and NERC the ability manage the compliance and enforcement processes and data in a single ERO Enterprise system. Today, those processes and related data are managed across three separate systems that have to be synchronized (webCDMS, CITS and CRATS).

E-ISAC Portal Enhancements
(Started Jan 2018/ Planned Completion Dec 2018)
As requested by and prioritized by the MEC, certain enhancements will be made to the E-ISAC portal during 2018 related to areas such as email notifications, user communities, and STIX-TAXII.

E-ISAC Document Management
(Started Apr 2018 / Planned Completion Jun 2018)
NERC launched the Document Management Program to provide a secure and efficient method of creating, collaborating, storing and disseminating the vast amount of information produced at NERC. The E-ISAC is the final business unit to be implemented.

Entity Registration – CORES (Discovery) and JRO (On Hold)
(Started Dec 2017 / Planned Completion May 2018)
NERC is undertaking an effort to both standardize and modernize the Entity Registration process. The discovery phase of the CORES project includes the capture of region specific needs, variations, and exceptions in the registration process. CORES will be a centralized entity registration process, which will require the retirement of registration in CDMS, CITS and CRATS. The JRO portion of the project was put on hold for construction, to be combined with the CORES production release in 2019.

SPP RE Transition
(Started Mar 2018 / Planned Completion Jul 2018)
With SPP dissolving, NERC is assessing the changes required to applications that contain SPP RE data and the reassignment/classification of such information. The inventory will require the mapping utility, functionality, migration, and support efforts by both region and entity. Activities include facilitated discussions with IT and business owners of impacted applications to capture and document high-level, as well as more detailed requirements necessary to support the transition of Registered Entities from SPP RE to MRO and SERC.

NERC.com Phase 2
(Started May 2017 / Completed Feb 2018)
In response to feedback from stakeholders, this project is a first step to improve the usability and search capability of the public NERC.com website. The project will also enhance the stability of the NERC.com platform with a technology upgrade from SharePoint 2010 to SharePoint 2016 in Azure.

SUPPLEMENTAL SCHEDULE 3

E-ISAC and CRISP
Summary of Activity

TOTAL E-ISAC (including CRISP)

FUNDING	YTD Actual	Annual Projection	Annual Budget	Projected Over (Under)
Assessments	$ 3,574,381	$ 14,297,524	$ 14,297,524	$ -
Other Funding	1,973,834	7,475,629	7,553,073	(77,444)
TOTAL FUNDING	$ 5,548,215	$ 21,773,153	$ 21,850,597	$ (77,444)
EXPENDITURES				
Personnel Expense	$ 1,272,816	$ 5,874,557	$ 6,004,182	$ (129,625)
Meeting Expense	110,730	456,530	418,000	38,530
Operating Expenses (excluding Depreciation)	1,920,740	8,354,207	8,549,624	(195,418)
Fixed Assets (including Allocations)	(87,151)	347,121	359,377	(12,256)
Indirect Expenses	1,344,356	5,933,723	6,519,415	(585,692)
TOTAL EXPENDITURES	$ 4,561,490	$ 20,966,138	$ 21,850,597	$ (884,460)
RESERVE INCREASE (DECREASE)	$ 986,725	$ 807,016	$ -	$ 807,016

SUPPLEMENTAL SCHEDULE 3
(continued)

CRISP

FUNDING	YTD Actual	Annual Projection	Annual Budget	Projected Over (Under)
Assessments	$ 342,942	$ 1,371,768	$ 1,371,768	$ -
Other Funding	1,856,443	7,275,084	7,348,144	(73,060)
TOTAL FUNDING	$ 2,199,385	$ 8,646,852	$ 8,719,912	$ (73,060)
EXPENDITURES				
Personnel Expense	$ 204,501	$ 930,187	$ 944,070	$ (13,882)
Meeting Expense	6,484	49,492	48,000	1,492
Operating Expenses (excluding Depreciation)	1,571,532	6,688,243	6,772,514	(84,271)
Fixed Assets (including Allocations)	(13,325)	114,154	114,113	41
Indirect Expenses	205,550	864,775	841,215	23,560
TOTAL EXPENDITURES	$ 1,974,742	$ 8,646,852	$ 8,719,912	$ (73,060)
RESERVE INCREASE (DECREASE)	$ 224,643	$ -	$ -	$ -

E-ISAC (excluding CRISP)

FUNDING	YTD Actual	Annual Projection	Annual Budget	Projected Over (Under)
Assessments	$ 3,231,439	$ 12,925,757	$ 12,925,757	$ -
Other Funding	117,391	200,545	204,929	(4,384)
TOTAL FUNDING	$ 3,348,830	$ 13,126,301	$ 13,130,686	$ (4,384)
EXPENDITURES				
Personnel Expense	$ 1,068,315	$ 4,944,370	$ 5,060,112	$ (115,742)
Meeting Expense	104,245	407,038	370,000	37,038
Operating Expenses (excluding Depreciation)	349,207	1,665,963	1,777,110	(111,147)
Fixed Assets (including Allocations)	(73,826)	232,967	245,263	(12,297)
Indirect Expenses	1,138,806	5,068,948	5,678,200	(609,252)
TOTAL EXPENDITURES	$ 2,586,748	$ 12,319,286	$ 13,130,686	$ (811,400)
RESERVE INCREASE (DECREASE)	$ 762,082	$ 807,016	$ -	$ 807,016

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Summary of Unaudited Results First Quarter 2018

Scott Jones, Senior Vice President, Chief Financial and Administrative Officer

Finance and Audit Committee Meeting

May 9, 2018

RELIABILITY | ACCOUNTABILITY

2018 First Quarter Results

- Total funding was $100k (0.6%) under budget
  - Testing fees and workshop fees slightly below budget
- Total expenditures were $1.8M (9.4%) under budget
  - Primarily due to the expected timing of expenditures versus budget
- Net impact was $1.7M increase in operating reserves

2018 Year-end Projections

- NERC projecting to be on budget for funding
- NERC projecting to be $600k (0.8%) over budget for costs
  - Personnel expenses expected to be slightly over budget
  - Contracts and consultants costs projected to be over budget primarily due to SPP RE transition work and a cybersecurity supply chain risk study
- Net impact of cost and funding projections is $600k additional decrease in operating reserves
- Financing activity is projected to be favorable by $500k

2018 Projected Year-end Reserves

- Total reserves balance is $9.2M
  - Operating Contingency Reserve (OCR) – $3.6M
  - Assessment Stabilization Reserve (ASR) – $2.1M
  - Future Obligation Reserve – $2.5M
  - System Operator Reserve – $510k
  - CRISP Reserve – $500k

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Questions and Answers

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

March 30, 2018

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: NERC Standards Report, Status and Timetable for Addressing Regulatory Directives
Docket No. RR09-6-003

Dear Secretary Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits the 2018 NERC Standards Report, Status and Timetable for Addressing Regulatory Directives (the "Directives Report") in accordance with Section 321.6 of the NERC Rules of Procedure ("ROP").[1] This annual report summarizes the progress made, and plans for addressing the Reliability Standards-related directives issued by applicable governmental authorities.

Section 321.6 of NERC's ROP requires NERC, on or before March 31 of each year, to file a report with applicable governmental authorities on the status and timetable for addressing each outstanding regulatory directive. As discussed in the attached Directives Report, since NERC's 2017 annual directives report filed on March 31, 2017, the Commission issued one directive.[2] In that time, NERC filed petitions with the Commission addressing 13 directives. Currently, there are 13 outstanding directives, six of which NERC is addressing through existing standards development current projects. The other outstanding directives are not related to Reliability Standards development (i.e., the directives relate to data gathering, registration, or the performance of research/studies) and being addressed through other mechanisms.

The 2018-2020 Reliability Standards Development Plan ("RSDP") provides a plan to address the remainder of the standards-related directives. NERC's annual RSDP establishes priorities related to Reliability Standards to help ensure that those issues that most directly impact Bulk-Power System reliability are addressed first. Directives to create new or modify existing Reliability Standards are assigned to existing

[1] The Federal Energy Regulatory Commission ("FERC" or "Commission") approved Rule 321 on March 17, 2011 in the above captioned docket. *Order on Compliance Filing*, 134 FERC ¶ 61,216 (2011).

[2] *See Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Order on GMD Research Work Plan, 161 FERC ¶ 61,048 (2017).

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or future development projects that are prioritized by the NERC Standards Committee and reflected in the RSDP. The 2018-2020 RSDP was filed with the Commission on December 21, 2017.[3]

The attached Directives Report includes the following appendices to aid in understanding the specific regulatory directives received to date and the standard development projects assigned to address those directives:

- Appendix A –Directives Issued by the Commission Since April 1, 2017
- Appendix B – Directives Addressed Since April 1, 2017
- Appendix C – Outstanding Directives

In prior years, the report included more historical data. Appendix A of the prior Directive Reports listed all FERC orders that included directives, including the date the order was issued, the numbers of directives from that order, and the year those directed were addressed. Further, Appendix B of those prior Directive Reports listed all of the directives issued by Commission since the initial set of NERC's Reliability Standards became mandatory and enforceable within the United States, and included a summary of each directive, information on the order in which it was issued, and the status of the directive. After consultation with Commission staff, NERC sought to streamline the Directives Report to provide updates on directives addressed since the last report and the status of any outstanding directives. As NERC has made significant progress over the last several years to remove the backlog of outstanding directives, the historical data was no longer a useful measure for tracking progress.

Please contact me if you have questions or need additional information.

Respectfully submitted,

/s/ Shamai Elstein

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[3] NERC's 2018-2020 RSDP is accessible at the following link: https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/2018-2020%20RSDP%20FERC%20Filing.pdf.

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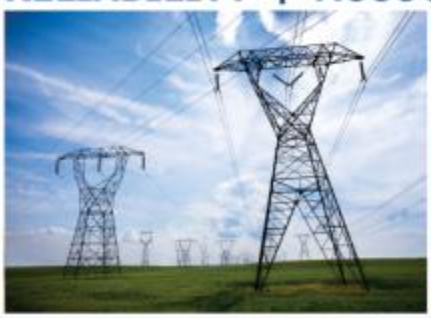
NERC Standards Report

Status and Timetable for Processing Regulatory Directives

March 30, 2018

RELIABILITY | ACCOUNTABILITY



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Outstanding Directives 14

Chapter 1 – Introduction

In accordance with Section 321.6 of the North American Electric Reliability Corporation ("NERC") Rules of Procedure ("ROP"),[1] this report provides an update on the status and timetable for addressing outstanding directives issued by the Federal Energy Regulatory Commission ("FERC" or "Commission"). This is the ninth annual directives report summarizing NERC's progress and plans for addressing outstanding directives issued by the Commission.

As discussed below, since NERC's 2017 annual directives report filed on March 31, 2017, the Commission has issued one directive.[2] In that time, NERC has filed petitions with the Commission addressing 13 outstanding directives. Currently, there are 13 outstanding directives, six of which NERC is addressing through existing standards development current projects. The other outstanding directives are not related to Reliability Standards development (i.e., the directives relates to data gathering, registration, or the performance of research/studies) and being addressed through other mechanisms.

NERC's 2018-2020 Reliability Standards Development Plan ("RSDP") provides a plan to address the outstanding Reliability Standards-related directives. NERC's annual RSDP establishes priorities related to Reliability Standards to help ensure that those issues that most directly impact Bulk-Power System reliability are addressed first. Directives to create new, or modify existing, Reliability Standards are assigned to existing or future development projects that are prioritized by the NERC Standards Committee and reflected in the RSDP. The 2018-2020 RSDP was filed with the Commission on December 21, 2017.[3]

[1] Section 321.6 of NERC's ROP requires NERC, on or before March 31 of each year, to file a report with applicable governmental authorities on the status and timetable for addressing each outstanding regulatory directive.

[2] *See Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events,* Order on GMD Research Work Plan, 161 FERC ¶ 61,048 (2017).

[3] NERC's 2018-2020 RSDP is accessible at the following link: https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/2018-2020%20RSDP%20FERC%20Filing.pdf.

Chapter 2 – Status of Directives

Appendix A to this report contains a list of all of the directives issued by Commission since the 2017 directives report. Appendix B contains a complete list of the directives NERC addressed since the 2017 directives report. Appendix C provides a list of the outstanding directives and an update on NERC's plans to address those directives.

Tabulated by year of issuance, the number of directives issued and addressed since 2007 is provided in Table 1:

Table 1: Directives by Year

Year	Issued	Addressed
2007	435	40
2008	123	99
2009	62	102
2010	67	49
2011	32	121
2012	18	31[4]
2013	42	143
2014	10	104
2015	26	80
2016	13	25
2017	5	14
2018 (through March 30, 2018)	0	5
Total	833	813

[4] A directive previously indicated as being resolved in 2012 was withdrawn by FERC Order 788 and, in turn, was moved to 2013.

Chapter 3 – Conclusion

NERC is continuing to work closely with industry stakeholders and FERC to resolve all outstanding directives. Completing the majority of this work has provided the opportunity for industry to strategically review the standards and address as many directives as possible to date.

Appendix A – Directives Issued Since April 1, 2017

Directives Issued by the Commission since April 1, 2017

Below is a list of all of the directives issued by Commission since the last directives report. The table includes a summary of the directive, information on the order in which it was issued, and the status of the directive.

Directives Issued by Commission Order since April 1, 2007						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Status**
"In addition, we direct NERC to file for Commission review a final, or otherwise updated, GMD Work Plan within six months of the date of this order."	Order on GMD Research Work Plan	10/19/2017		161 FERC ¶ 61,048/ RM15-11-002	1	On track to be filed April 19, 2018.

Appendix B –Directives Addressed since April 1, 2017

Directives Addressed Since April 1, 2017

Below is a list of all of the directives NERC addressed since the last directives report. The table includes a summary of the directive, the action taken to address the directive, as well as the NERC project name and date of filing with the Commission.

Directives Addressed since April 1, 2017			
Directive Summary	**Action Taken**	**Project Name**	**Filing Date**
S-Ref 10919 - The Commission adopts the proposal to direct NERC to make an informational filing addressing whether Reliability Standard CIP-014-1 provides physical security for all "High Impact" control centers, as that term is defined in Reliability Standard CIP-002-5.1, necessary for the reliable operation of the Bulk-Power System. However, the Commission extends the deadline for that informational filing until two years following the effective date of Reliability Standard CIP-014-1. The Commission adopts the NOPR proposal and directs NERC to submit an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cybersecurity and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers. The Commission, however, modifies the NOPR proposal and extends the due date for the informational filing to two years following the effective date of Reliability Standard CIP-014-1. NERC indicated that NERC staff will submit to the NERC Board of Trustees a report three months following implementation of Requirements R1, R2 and R3 concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC also committed to sending this report to Commission staff.	Report submitted to FERC	CIP-014 Report Physical Security Protection for High Impact control Centers	10/2/2017
S-Ref 10920 - "[W]e direct NERC to obtain, maintain, and make available to the Commission upon request, one year following the effective date of the standard and on an annual basis thereafter, data sufficient to analyze the effectiveness of PRC-005-3, whether it be through NERC's Event Analysis process or other means.	The Events Analysis process now collects data on how many times auto-reclosing has	NA	Data is being collected as part of NERC's Events Analysis process and will be made available to the Commission upon request.

Directives Addressed since April 1, 2017			
Directive Summary	**Action Taken**	**Project Name**	**Filing Date**
Specifically, NERC is to collect relevant information regarding Bulk-Power System events that involve high speed auto-reclosing relays. Such information would include the operations of auto-reclosing relays and their supervisory functionalities (e.g., time delays, synchronism check, voltages, etc.) that caused or exacerbated the events, and any unintended consequences of the events. The Commission encourages NERC and FERC staff to collaborate on the specific data to be collected, which could include, but is not limited to, the approximate distance from the fault and the generation loss associated with the event. Further, the Commission is also interested in knowing if those auto-reclosing relays identified as causing or exacerbating an event operated as designed, and if PRC-005-3 is applicable to the auto-reclosing relays that were involved. We expect NERC to share all appropriate data as needed to evaluate auto-reclosing relay performance, in accordance with our general expectation that NERC will "cooperate with and share all appropriate data and information with Commission staff" as needed "to ensure that the ERO Enterprise and the Commission are both able to effectively perform their duties under section 215 of the FPA."	an effect on a reportable event.		
S-Ref 10949 - "[W]e direct NERC to conduct a study that assesses the effectiveness of the CIP version 5 remote access controls, the risks posed by remote access-related threats and vulnerabilities, and appropriate mitigating controls for any identified risks. NERC should consult with Commission staff to determine the general contents of the directed report. We direct NERC to submit a report on the above outlined study within one year of the implementation of the CIP version 5 Standards for High and Medium Impact BES Cyber Systems."	NERC filed a Remote Access Study Report	NA	6/30/2017
S- Ref 10951 - "[W]e direct 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	NERC developed a new standard (CIP-013-1) and modified two existing standards (CIP-005-6, CIP-010-2).	2016-03	9/26/2017

Directives Addressed since April 1, 2017			
Directive Summary	**Action Taken**	**Project Name**	**Filing Date**
detail below: (1) software integrity and authenticity; (2) vendor remote access; (3) information system planning; and (4) vendor risk management and procurement controls. In making this directive, the Commission does not require NERC to impose any specific controls, nor does the Commission require NERC to propose "one-size-fits-all" requirements. The new or modified Reliability Standard should instead require responsible entities to develop a plan to meet the four objectives, or some equally efficient and effective means to meet these objectives, while providing flexibility to responsible entities as to how to meet those objectives."			
S-Ref 10952P44: "[T]he Commission, as proposed in the NOPR, directs NERC to develop revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data." P47: "Without prejudging how NERC proposes to address the Commission's directive, NERC's response to this directive should satisfy the NOPR's concern that reliance on spatially-averaged data alone does not address localized peaks that could potentially affect the reliable operation of the Bulk-Power System." P48: "NERC could revise [the standard] to apply a higher reference peak geoelectric field amplitude value to assess the impact of localized hot spots on the Bulk-Power System, as suggested by the Trade Associations." P49: "Consistent with Order No. 779, the Commission does not specify a particular reference peak geoelectric field amplitude value that should be applied to hot spots given present uncertainties."	TPL-007-1 was revised to address the directives.	2013-03	1/22/2018
S-Ref 10953- P65: "Consistent with our determination above regarding the reference peak geoelectric field amplitude value, the Commission directs NERC to revise Requirement R6 to require registered entities to apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient	TPL-007-1 was revised to address the directives.	2013-03	1/22/2018

Directives Addressed since April 1, 2017			
Directive Summary	**Action Taken**	**Project Name**	**Filing Date**
and effective alternative, when conducting thermal impact assessments."			
S-Ref 10954 P 88: "The Commission … adopts the NOPR proposal in relevant part an directs NERC to develop revisions to Reliability Standard TPL-007-1 to require responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness, including from any devices that must be added to meet this need. The NERC standard drafting team should address the criteria for collecting GIC monitoring and magnetometer data discussed below and provide registered entities with sufficient guidance in terms of defining the data that must be collected, and NERC should propose in the GMD research work plan how it will determine and report on the degree to which industry is following that guidance." Magnetometer Requirements P90: "In developing a requirement regarding the collection of magnetometer data, NERC should consider the following criteria discussed at the March 1, 2016 Technical Conference: (1) the data is sampled at a cadence of at least 10-seconds or faster; (2) the data comes from magnetometers that are physically close to GIC monitors; (3) the data comes from magnetometers that are not near sources of magnetic interference (e.g., roads and local distribution networks); and (4) data is collected from magnetometers spread across wide latitudes and longitudes and from diverse physiographic regions." GIC Requirements P 91: "Each responsible entity that is a transmission owner should be required to collect necessary GIC monitoring data. However, a transmission owner should be able to apply for an exemption from the GIC monitoring data collection requirement if it demonstrates that little or no value would be added to planning and operations.	TPL-007-1 was revised to address the directives.	2013-03	1/22/2018

Directives Addressed since April 1, 2017			
Directive Summary	**Action Taken**	**Project Name**	**Filing Date**
In developing a requirement regarding the collection of GIC monitoring data, NERC should consider the following criteria discussed at the March 1, 2016 Technical Conference: (1) the GIC data is from areas found to have high GIC based on system studies; (2) the GIC data comes from sensitive installations and key parts of the transmission grid; and (3) the data comes from GIC monitors that are not situated near transportation systems using direct current (e.g., subways or light rail." *** P 91: GIC monitoring and magnetometer locations should also be revisited after GIC system models are run with improved ground conductivity models. NERC may also propose to incorporate the GIC monitoring and magnetometer data collection requirements in a different Reliability Standard (e.g., real-time reliability monitoring and analysis capabilities as part of the TOP Reliability Standards). P 92: "[T]he Commission determines that requiring responsible entities to collect necessary GIC monitoring and magnetometer data, rather than install GIC monitors and magnetometers, affords greater flexibility while obtaining significant benefits."			
S-ref 10955 P 101: "The Commission directs NERC to modify Reliability Standard TPL-007-1 to include a deadline of one year from the completion of the GMD Vulnerability Assessments to complete the development of corrective action plans." P 102: "The Commission also directs NERC to modify Reliability Standard TPL-007-1 to include a two-year deadline after the development of the corrective action plan to complete the implementation of non-hardware mitigation and four-year deadline to complete hardware mitigation…" "The Commission agrees that NERC should consider extensions of time on a case-by-case basis."	TPL-007-1 was revised to address the directives.	2013-03	1/22/2018

Directives Addressed since April 1, 2017			
Directive Summary	**Action Taken**	**Project Name**	**Filing Date**
S-Ref 10956 P 77: "First, the Commission adopts the NOPR proposal and directs NERC to submit a GMD research work plan and, subsequently, informational filings that address the GMD-related research areas identified in the NOPR, additional research tasks identified in this Final Rule… and, in NERC's discretion, any GMD-related research areas generally that may impact the development of new or modified GMD Reliability Standards." "The research required by this directive should be informed by ongoing GMD-related research efforts of entities such as [USGS], [NOAA], [NASA], [DOE], academic and other publicly available contributors, including work performed for the National Space Weather Action Plan." P 81: "[W]e do not set specific deadlines for completion of the research; we only require NERC to submit the GMD research work plan within six months of the effective date of a final rule. The GMD research work plan, in turn, should include target dates for the completion of research topics and the reporting of findings to the Commission. The Commission intends to notice and invite comment on the GMD research work plan. An extension of time to submit the GMD research work plan may be available if six months proves to be insufficient. In addition, given the uncertainties commonly associated with complex research projects, the Commission will be flexible regarding changes to the tasks and target dates established in the GMD research work plan."	A GMD work plan was created and filed.	NA	5/30/2017
S-Ref 10956- P68: "[W]e direct NERC to assign a "high" violation risk factor to Reliability Standard BAL-002-2, Requirements R1 and R2."	BAL-002-02 was revised to address the directive	NA	8/14/2017

Directives Addressed since April 1, 2017			
Directive Summary	**Action Taken**	**Project Name**	**Filing Date**
S-Ref 10752 - The Commission directs RFC to add time horizons to the two main requirements when RFC reviews BAL-502-RFC-02 at the scheduled five-year review.	BAL-502-RF-003 was revised to address the directive.	Regional Standard	9/7/2017
S-Ref 10753 - Consider, at the time of its five-year review, whether to add a requirement to BAL-502-RFC-02 that would require 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.	BAL-502-RF-003 was revised to address the directive.	Regional Standard	9/7/2017
S-Ref 10893 - Direct NERC to report on the use of footnote 12 including the use and effectiveness of the local regulatory review and NERC review. This report is important because it will provide an analysis of the use of footnote 12, including but not limited to information on the duration, frequency and magnitude of planned non-consequential load loss, and typical (and if significant, atypical) scenarios where entities plan for non-consequential load loss.	Data was collected and filed with FERC.	NA	3/30/2018

Appendix C – Outstanding Directives

Outstanding Directives

Below is a list of the outstanding directives as of the date of this filing.

Table 3: Directives by Commission Order

Directive Summary	Owner	Publication Date	Order No.	FERC ORDER / DOCKET	Paragraph Reference	Project Number	Project Name	Status
S-Ref 10101 - Collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results to develop a standard that would apply to both federal and non-federal lands. NERC should gather and analyze the necessary data regarding vegetation management issues on public lands. If NERC's analysis indicates that there are issues that should be addressed, NERC should propose a means to address the concern, for example by issuing an alert, or propose other appropriate action."	Performance Analysis	3/16/2007; 3/21/2013	Order 693, 777	RM06-16-000; RM12-4-000	Order 693 Para 732; Order 777 Para 129, 130	NA	NA	Ongoing- NERC is currently analyzing data.
S-Ref 10917 - Accordingly, should NERC make changes to Table 1 based upon NERC's Procedure document, the Commission directs NERC to submit an informational notice describing the basis for the changes at least 30 days in advance of the effective date of any such changes.	Performance Analysis	1/16/2014	Order 794	RM13-11-000	Para 100	NA	NA	Table 1 was not modified last year. For details, see FRAA filed in this docket on November 29, 2017.

Table 3: Directives by Commission Order								
Directive Summary	**Owner**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Status**
S-Ref 10912 - The Commission directs NERC to continue its evaluation of the use of the linear regression methodology based upon experience and data collected following the implementation of BAL-003-1 and to submit a report to the Commission within three months after two years of operating experience once Requirement R1 of BAL-003-1 becomes effective (i.e., 27 months from the effective date of Requirement R1). The report should assess the accuracy of the linear regression methodology compared to the median methodology for purposes of determining Frequency Response Measure. Based on this report and actual experience, the Commission may revisit this issue.	Performance Analysis	1/16/2014	Order 794	RM13-11-000	Para 34	NA	NA	On track for submission on July 1, 2018.
S-Ref 10913 - The Commission adopts the NOPR proposal and directs NERC to submit a report that provides an analysis of the availability of resources for each balancing authority and Frequency Response Sharing Group to meet its Frequency Response Obligation during the first year of implementation. However, NERC indicates in its comments that it needs more than the proposed 15 months to prepare the report based on the time frame for NERC to receive relevant data from applicable entities. Accordingly, we direct NERC to submit this report within 27 months of implementation of Requirement R1. Further, consistent with NERC's representation in its comments, the Commission directs that, upon completion of the required analysis, should the findings indicate that the Frequency Response Obligation was not met, NERC shall provide appropriate recommendations to ensure that frequency response can be maintained at all times within each balancing authority's footprint.	Performance Analysis	1/16/2014	Order 794	RM13-11-000	Para 60	NA	NA	On track for submission on July 1, 2018.

Table 3: Directives by Commission Order								
Directive Summary	**Owner**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Status**
S-Ref 10894 - Direct NERC to modify Reliability Standard TPL-001-4 to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments.	Standards	10/17/2013	Order 786	RM12-1-000 and RM13-9-000	Para 40	2015-10	Single Points of Failure	In development
S-Ref 10896 - Directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4.	Standards	10/17/2013	Order 786	RM12-1-000 and RM13-9-000	Para 89	2015-10	Single Points of Failure	In development
S-Ref 10871 - …a. "As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners." (P 6) "NERC must establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners. Left to NERC how to accomplish this objective. Commission identifies modification of FAC-014 as a vehicle that would meet the objective." (P 41) "NERC should inform the Commission of when it has developed means for communication of IROLs to transmission owners to help ensure that they receive notice of each of their applicable lines before the standard becomes effective as to those lines." (P 42)	Standards	3/21/2013	Order 777	RM12-4-000	Para 6, 41, 42	NA	NA	Directive is currently being reviewed by the Operating Committee's Method for Establishing IROL Task Force.
S-Ref 10820 - The Commission "believe that NERC should register demand side aggregators if the loss of their load shedding capability, for reasons such as a cyber incident, would affect the reliability or operability of the Bulk-Power System."	Registration	1/18/2008	Order 706	RM06-22-000	Para 051	NA	NA	Ongoing

Table 3: Directives by Commission Order								
Directive Summary	**Owner**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Status**
S-Ref 10948 - "[W]e adopt the NOPR proposal and direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to require responsible entities to implement controls to protect, at a minimum, communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact)."	Standards	1/21/2016	Order No. 822	RM15-14-000	Para 53	2016-02	Modifications to CIP Standards	In development
S-Ref 10957 - COLLECT EXISTING AND NEW GIC/MAGNETOMETER DATA AND MAKE IT PUBLICLY AVAILABLE P 88: "[T]he Commission directs NERC, pursuant to Section 1600 of the NERC Rules of Procedure, to collect GIC monitoring and magnetometer data from registered entities for the period beginning May 2013, including both data existing as of the date of this order and new data going forward, and to make that information available." FN118: "The Commission's directives to collect and make available GIC monitoring and magnetometer data do not apply to non-U.S. responsible entities or Alaska and Hawaii." P 93: "We also direct NERC, pursuant to Sections 1500 and 1600 of the NERC Rules of Procedure, to collect and make GIC monitoring and magnetometer data available." FN 112: "If GIC monitoring and magnetometer data is already publicly available (e.g., from a government	Standards	9/22/2016	Order 830	RM15-11-000	Para 88, 93-95	NA	NA	A draft Section 1600 data request has been developed, submitted to FERC staff, and was posted for public comment through March 26, 2018.

Table 3: Directives by Commission Order								
Directive Summary	**Owner**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Status**
entity or university), NERC need not duplicate these efforts." P 94: "Based on the record in this proceeding, we believe that GIC and magnetometer data typically should not be designated as Confidential Information under the NERC Rules of Procedure." 95: "Notwithstanding our findings here, to the extent any entity seeks confidential treatment of the data it provides to NERC, the burden rests on that entity to justify the confidential treatment. Exceptions are possible if the providing entity obtains from NERC, at the time it submits data to NERC, a determination that GIC or magnetometer data qualify as Confidential Information. Entities denied access to GIC and magnetometer data by NERC or providers denied Confidential Information treatment of GIC and magnetometer data may appeal NERCs decision to the Commission."								
S-Ref 10953 - P23: "[W]e direct NERC to develop modifications to Reliability Standard BAL-002-2 to address our concerns, discussed below, regarding the 15-minute ACE recovery period set forth in Requirement R1." P37: "[W]e direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require balancing authorities or reserve sharing groups: (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time. NERC may also	Standards	1/19/2017	Order 835	RM16-7	Para 23 and Para 37	2017-06	Modifications to BAL-002-2	In development

Table 3: Directives by Commission Order								
Directive Summary	**Owner**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Status**
propose an equally efficient and effective alternative."								
S-Ref 10954 - P23: "We also direct NERC to collect and report on data pertaining to the occurrence of Balancing Contingency Events that trigger resets of the 90-minute Contingency Reserve Restoration Period under Requirement R3." S-Ref 10954 - P46: "[T]he Commission directs NERC to collect and report data pertaining to: (1) additional megawatt losses following Reportable Balancing Contingency Events during the Contingency Reserve Restoration Period; and (2) the time periods for contingency reserve restoration under Requirement R3 and the number of resets of the 90-minute restoration period, and submit a report to the Commission two years following the first day of implementation of Requirement R3. After NERC reports on the data in a compliance filing, the Commission will consider what further action, if any, to take."	Performance Analysis	1/19/2017	Order 835	RM16-7	Para 23 and Para 46	NA	NA	Data is currently being collected.
S-Ref 10955 - P23: "We further direct NERC to study and submit a report to the Commission with findings regarding reliability risks associated with most severe single contingency exceedances that do not result in energy emergencies."	Performance Analysis	1/19/2017	Order 835	RM16-7	Para 23	NA	NA	Data is currently being collected.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

June 4, 2018

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Petition for Approval of Amendments to the Bylaws of the North American Electric Reliability Corporation
Docket No. RR18-_-000

Dear Secretary Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits a "*Petition for Approval of Amendments to the Bylaws of the North American Electric Reliability Corporation*." As described in greater detail in the Petition, NERC proposes to amend the Bylaws by reducing the required timeframe for notice of special closed sessions of the Board of Trustees. In addition, NERC also proposes to correct a minor typographical error in Article VIII, Section 1(b) of the Bylaws.

This filing consists of: (1) this transmittal letter; (2) the narrative text of the filing; and (3) **Attachments 1** and **2** which contain clean and redline versions of the proposed amendments to NERC Bylaws, respectively. All documents are transmitted in a single PDF file.

Please contact the undersigned if you have any questions concerning this filing.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR18-_-000**

PETITION
FOR APPROVAL OF AMENDMENTS TO THE BYLAWS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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June 4, 2018

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR18-_-000**

PETITION FOR APPROVAL OF AMENDMENTS TO THE BYLAWS OF THE NORTH AMERICAN RELIABILITY CORPORATION

Pursuant to § 215(f) of the Federal Power Act ("FPA")[1] and 18 C.F.R. § 39.10[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC") hereby requests Commission approval of proposed amendments to the NERC Bylaws. The NERC Bylaws are "Electric Reliability Organization Rules" as defined in 18 C.F.R. § 39.10, and, in accordance with 18 C.F.R. § 39.10, require Commission approval.[3]

NERC proposes to amend Article V, Section 1 of the Bylaws to reduce the 5 day prior notice requirement for Board of Trustee ("Board") meetings. This amendment will allow for a 24 hour prior notice for special board meetings that are held in closed session. However, the revision 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 Board of Trustees. Specifically, the shortened notice period will permit the Board to address matters that may be considered during a closed session in a more timely manner when necessary, while not changing the notice provided to stakeholders of any Board meeting.

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1 16 U.S.C. § 824o (2006).
2 18 C.F.R. § 39.5 (2018).
3 18 C.F.R. § 39.10 (2018).

Below are the texts of the proposed amendments to Section 2 of Article V and Section 1 of Article VIII of the Bylaws. **Attachments 1** and **2** to this filing contain the complete NERC Bylaws with the proposed amendments, in clean and redlined format, respectively.

ARTICLE V

Meetings of the Board of Trustees

Section 2 - Special Meetings of the Board - Special meetings of the board for any purpose or purposes may be called at any time by the chairman or by any two trustees. Such meetings may be held upon notice given to all trustees not less than five (5) days prior to the date of the meeting unless the meeting is a closed session as permitted by Article V, Section 4 of these Bylaws, in which event the notice shall be provided to all trustees not less than 24 hours prior to the date and time of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, telegraph or other electronic media, or by express delivery.

ARTICLE VIII

Member Representatives Committee

Section 1 - Member Representatives Committee - The Corporation shall have a Member Representatives Committee that shall have the following rights and obligations:

a. to elect the independent trustees, in accordance with Article III, Section 6;
b. to vote on amendments to the Bylaws, in accordance with Article ~~XVI~~XIV; and
c. to provide advice and recommendations to the board with respect to the development of annual budgets, business plans and funding mechanisms, and other matters pertinent to the purpose and operations of the Corporation.

Because it is elected by the members of the Corporation and not appointed by the board, the Member Representatives Committee shall not be a standing committee of the Corporation, but is authorized to provide its advice and recommendations directly to the board.

I. APPROVAL PROCESS FOR THE BYLAW AMENDMENTS

Article XIV, Section 1 of the NERC Bylaws sets forth the required procedure for approval of amendments to the Bylaws:

> **Section 1 – Amendments to the Bylaws –** These Bylaws may be altered, amended, or repealed by a majority vote of both the board and the Member Representatives Committee at respective meetings of the board and the Members Representative Committee at which a quorum is present. Written notice of the subject matter of the proposed changes to the Bylaws shall be provided, as appropriate, to the trustees or to the Member Representatives Committee not less than ten (10) nor more than sixty (60) days prior to the date of the meeting of the board or of the Member Representatives Committee at which the vote is to be taken. Notwithstanding the provisions of this Article XIV, the members of the Corporation voting by sector shall have the right to alter, amend, or repeal Bylaws adopted by the board and the Member Representatives Committee and to adopt new Bylaws, provided that any such alteration, amendment, or repeal or the adoption of new Bylaws is approved by vote of two-thirds of the sectors at a meeting of Members called for that purpose, or by written consent of two-thirds of the sectors, where the number of votes for and against the proposed alteration, amendment, repeal, or adoption of Bylaws shall be determined in accordance with Section 2 of Article IV. Any alteration, amendment, repeal, or adoption of Bylaws shall be subject to any applicable requirements for filing with or approval by the Commission and any other applicable governmental authority.

The requirements of Article XIV, Section 1 were followed in obtaining approval of the proposed amended Bylaws that are the subject of this filing. At the January 24, 2018 Corporate Governance and Human Resources Committee meeting, NERC management recommended adoption of these revisions to the NERC Bylaws. On February 8, 2018, the NERC Board of Trustees, upon the recommendation of the Corporate Governance and Human Resources Committee, approved the proposed revisions to the NERC Bylaws. The proposed amended Bylaws were approved by the MRC at its meeting held on May 9, 2018. The applicable notice was provided to the Board of Trustees and the MRC, respectively, upon the public posting of their agenda packages. The required quorums of the Board and the MRC were present at their respective meetings.

II. CONCLUSION

NERC respectfully requests that the Commission approve the proposed amendments to the NERC Bylaws, as shown in **Attachments 1** and **2** to this Petition.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston

Nina H. Jenkins-Johnston
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Counsel for the North American Electric Reliability Corporation

Dated: June 4, 2018

ATTACHMENT 1

Amended North American Electric Reliability Corporation Bylaws – **Clean**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Bylaws

Approved by the Board of Trustees: February 8, 2018
Effective: [Proposed Date]

BYLAWS

OF THE

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ARTICLE I
Definitions

Section 1 — Definitions — As used in these Bylaws of the North American Electric Reliability Corporation (hereinafter referred to as "the Corporation"), the terms set forth in this Article I shall have the meanings set forth herein.

"Applicable governmental authority" means the Federal Energy Regulatory Commission within the United States and the appropriate governmental authority with subject matter jurisdiction over reliability within Canada and Mexico.

"Board" means the Board of Trustees of the Corporation.

"Bulk power system" means facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and 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.

"Commission" means the Federal Energy Regulatory Commission.

"Electric reliability organization" or "ERO" means the organization that is certified by the Commission under Section 39.3 of its regulations, the purpose of which is to establish and enforce Reliability Standards for the bulk power system in the United States. The organization may also have received recognition by applicable governmental authorities in Canada and Mexico to establish and enforce reliability standards for the bulk power systems of the respective countries.

"Member" means a member of the Corporation pursuant to Article II of these Bylaws.

"Net Energy for Load (NEL)" means 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 storage of energy at energy storage facilities. Calculations of net energy for load for all purposes under these Bylaws shall be based on the most recent calendar year for which data on net energy for load of applicable regions of the United States, Canada, and Mexico is available.

"Regional entity" means an entity having enforcement authority pursuant to 18 C.F.R. § 39.8.

"Reliability standard" means a requirement to provide for reliable operation of the bulk power system, including without limiting the foregoing requirements for the operation of existing bulk power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary for reliable operation of the bulk power system, but shall not include any requirement to enlarge bulk power system facilities or to construct new transmission capacity or generation capacity.

"Reliable operation" means operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of the bulk power system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

"Sector" means a group of members of the Corporation that are bulk power system owners, operators, or users or other persons and entities with substantially similar interests, including governmental entities, as pertinent to the purposes and operations of the Corporation and the operation of the bulk power system, as defined in Article II, Section 4 of these Bylaws. Each sector shall constitute a class of members for purposes of the New Jersey Nonprofit Corporation Act.

Section 2 — Additional Defined Terms — Additional terms not defined in this Article I are defined in the remainder of these Bylaws.

Section 3 — Technical Terms — Technical terms not defined in these Bylaws shall have the definitions set forth in the Federal Power Act, Part 39 of the regulations of the Commission, or the "Glossary of Terms Used in Reliability Standards", in that order of precedence, and if not defined in any of those sources, shall be defined in accordance with their commonly understood and used technical meaning in the electric power industry, including applicable codes and standards.

ARTICLE II
Membership

Section 1 — Members — Membership in the Corporation is voluntary and is open to any person or entity that has an interest in the reliable operation of the North American bulk power system and that registers with the Corporation as a member, maintains its registration in accordance with this Article II, and complies with the other conditions and obligations of membership specified in these Bylaws. Membership in a regional entity shall not be a condition for membership in the Corporation. The secretary of the Corporation shall maintain a roster of the members of the Corporation.

Section 2 — Registration as a Member — Any person or entity that is eligible to be a member of the Corporation in accordance with Article II, Section 1 may become a member by completing, and submitting to the secretary of the Corporation, a membership registration on a form prescribed by the board. If not a natural person, the member shall designate a

representative and an alternative representative with authority to receive notices, cast votes, and execute waivers and consents on behalf of the member. The secretary of the Corporation shall maintain a current roster of the members of the Corporation including each member's designated representative and alternative representative. From time to time, the board shall establish a date by which members shall submit their registration renewals. All members shall be required to renew their registrations within 30 calendar days of a request by the secretary of the Corporation, using a registration renewal form prescribed by the board. The secretary of the Corporation shall remove from the roster of members of the Corporation any member that has not submitted a registration renewal within 30 days following a date established by the board. The secretary shall notify any member that is removed from the roster of members of such removal, by notice sent to such former member's last known address on the records of the Corporation.

Section 3 — Obligations and Conditions of Membership

a. Each member shall agree, in writing, to accept the responsibility to promote, support, and comply with the purposes and policies of the Corporation as set forth in its Certificate of Incorporation, Bylaws, Rules of Procedure, and Reliability Standards as from time to time adopted, approved, or amended.

b. As an additional condition of membership in the Corporation, each person or entity registering as a member shall be required to execute an agreement with the Corporation, in a form to be specified by the board, that such person or entity will hold all trustees, officers, employees, and agents of the Corporation, as well as volunteers participating in good faith in the activities of the Corporation, harmless, to the extent permitted by Federal or provincial laws, regulations and rules, for any injury or damage to that member caused by any act or omission of any trustee, officer, employee, agent, or volunteer in the course of performance of his or her duties on behalf of the Corporation, other than for acts of gross negligence, intentional misconduct, or a breach of confidentiality.

Section 4 — Membership Sectors

a. Each member shall elect to be assigned to one of the following membership sectors: (i) investor-owned utility; (ii) state/municipal utility; (iii) cooperative utility; (iv) federal or provincial utility/power marketing administration; (v) transmission-dependent utility; (vi) merchant electricity generator; (vii) electricity marketer; (viii) large end-use electricity customer; (ix) small end-use electricity customer; (x) independent system operator/regional transmission organization; (xi) regional entity; or (xii) government representatives. The composition of each sector shall be as follows:

    i. Investor-owned utility — This sector includes any investor-owned entity with a substantial business interest in ownership and/or operation in any of the asset categories of generation, transmission or distribution. This sector also includes organizations that represent the interests of such entities.

ii. State/municipal utility — This sector includes any entity owned by or subject to the governmental authority of a state or municipality, that is engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the state or municipality; and any entity, whose members are municipalities, formed under state law for the purpose of generating, transmitting, or purchasing electricity for sale at wholesale to their members. This sector also includes organizations that represent the interests of such entities.

iii. Cooperative utility — This sector includes any non-governmental entity that is incorporated under the laws of the state in which it operates, is owned by and provides electric service to end-use customers at cost, and is governed by a board of directors that is elected by the membership of the entity; and any non-governmental entity owned by and which provides generation and/or transmission service to such entities. This sector also includes organizations that represent the interests of such entities.

iv. Federal or provincial utility/Federal Power Marketing Administration — This sector includes any U.S. federal, Canadian provincial, or Mexican entity that owns and/or operates electric facilities in any of the asset categories of generation, transmission, or distribution; or that functions as a power marketer or power marketing administrator. This sector also includes organizations that represent the interests of such entities.

v. Transmission-dependent utility — This sector includes any entity with a regulatory, contractual, or other legal obligation to serve wholesale aggregators or customers or end-use customers and that depends primarily on the transmission systems of third parties to provide this service. This sector also includes organizations that represent the interests of such entities.

vi. Merchant electricity generator — This sector includes any entity that owns or operates an electricity generating facility that is not included in an investor-owned utility's rate base and that does not otherwise fall within any of sectors (i) through (v). This sector includes but is not limited to cogenerators, small power producers, and all other nonutility electricity producers such as exempt wholesale generators who sell electricity at wholesale. This sector also includes organizations that represent the interests of such entities.

vii. Electricity marketer — This sector includes any entity that is engaged in the activity of buying and selling of wholesale electric power in North America on a physical or financial basis. This sector also includes organizations that represent the interests of such entities.

viii. Large end-use electricity customer — This sector includes any entity in North America with at least one service delivery taken at 50 kV or higher (radial supply or facilities dedicated to serve customers) that is not purchased for resale; and any single end-use customer with an average aggregated service load (not purchased for resale) of at least 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations that represent the interests of such entities.

ix. Small end-use electricity customer — This sector includes any person or entity within North America that takes service below 50 kV; and any single end-use customer with an average aggregated service load (not purchased for resale) of less than 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations (including state consumer advocates) that represent the interests of such entities.

x. Independent system operator/regional transmission organization — This sector includes any entity authorized by the Commission to function as an independent transmission system operator, a regional transmission organization, or a similar organization; comparable entities in Canada and Mexico; and the Electric Reliability Council of Texas or its successor. This sector also includes organizations that represent the interests of such entities.

xi. Regional entity — This sector includes any regional entity as defined in Article I, Section 1.

xii. Government representatives — This sector includes any federal, state, or provincial government department or agency in North America having a regulatory and/or policy interest in wholesale electricity. Entities with regulatory oversight over the Corporation or any regional entity, including U.S., Canadian, and Mexican federal agencies and any provincial entity in Canada having statutory oversight over the Corporation or a regional entity with respect to the approval and/or enforcement of reliability standards, may be nonvoting members of this sector.

b. A member may elect to be assigned to any sector so long as membership in that sector is consistent with the member's business or other activities. A corporation and its affiliates shall be considered a single member and may register in only one sector, which may be any single sector for which the corporation or any of its affiliates is eligible. A consultant, attorney, agent, vendor, trade or industry association, state, provincial or local consumer advocate organization that provides services to or otherwise represents the interests of the members of one or more sectors may elect to be assigned to one such sector.

Section 5 — Term of Membership — Membership in the Corporation shall be retained as long as a member meets its respective qualifications, obligations, and conditions of membership as set forth in this Article II.

Section 6 — Removal — In addition to termination of membership in accordance with Article II, Section 2, the board, following notice to the member and exercise of appropriate due process procedures, may terminate the membership of a member if in the judgment of the board that member has violated its obligations and responsibilities to the Corporation. This termination shall require a two-thirds vote of the trustees present and voting at a meeting of the board at which a quorum of the board entitled to vote is present. Within thirty (30) days following the action of the board terminating the membership of a member, the member shall be entitled to appeal such termination to the Commission or to the applicable governmental authority in Canada or Mexico.

ARTICLE III
Board of Trustees

Section 1 — Board of Trustees — The business and affairs of the Corporation shall be managed by a Board of Trustees. The board shall consist of eleven members (the "trustees"), unless it is increased to twelve members pursuant to Section 1a of this Article III. All but one of the trustees shall be "independent" trustees nominated and elected in accordance with the requirements and procedures specified in Sections 2, 3, 4, 5, and 6 of this Article III (the "independent trustees"). The remaining trustee shall be the person elected by the board, in accordance with Article VI, Section 1, of these Bylaws, to serve as president of the Corporation (the "management trustee"). Each trustee, including the management trustee, shall have one (1) vote on any matter brought before the board for a vote. All trustees are expected to serve the public interest and to represent the reliability concerns of the entire North American bulk power system.

Section 1a — Increase in number of trustees — The board shall have the authority, by resolution, to increase the number of trustees from eleven to twelve, of which eleven trustees shall be independent trustees, with such increase to be effective as of the date of an annual election of independent trustees pursuant to Section 6 of this Article III. In order for the board to exercise this authority, the resolution increasing the number of trustees from eleven to twelve must be adopted by the board no later than December 1 immediately preceding the date of the annual election of independent trustees at which the increase is to be effective, and shall state a determination by the board that the increase is in the best interests of the Corporation and its Members. If the board adopts a resolution increasing the number of trustees from eleven to twelve, the nominating committee appointed pursuant to Section 5 of this Article III shall nominate a candidate to stand for election to the newly-created independent trustee position at the next annual election of independent trustees, along with candidates for the positions of independent trustees whose terms are expiring as of such election. The newly-created independent trustee position shall be filled by election in accordance with Section 6 of this Article III. Upon election of a trustee to the newly-created independent trustee position, the board shall thereafter consist of twelve trustees, of whom eleven shall be independent trustees and one shall be the management trustee provided for in Section 1 of this Article III, unless the

board decreases the number of trustees in accordance with Section 1b of this Article III.

Section 1b — Decrease in number of trustees — If the board has previously increased the number of trustees under Section 1a of this Section III, the board shall have the authority, by resolution, to decrease the number of trustees from twelve to eleven, of which ten trustees shall be independent trustees, with such decrease to be effective as of the date of an annual election of independent trustees pursuant to Section 6 of this Article III. The decrease in number of trustees shall be effected by eliminating one of the independent trustee positions whose term is expiring as of the date of such annual election of trustees, in which case no election shall be held to replace such trustee. In order for the board to exercise this authority, the resolution decreasing the number of trustees from twelve to eleven must be adopted by the board no later than September 1 immediately preceding the date of the annual election of independent trustees at which the decrease is to be effective; shall identify the independent trustee position expiring at the date of such annual election that shall be eliminated; and shall state a determination by the board that the decrease is in the best interests of the Corporation and its Members.

Section 2 — Composition of Board Based on Country Participation

a. The board shall consist of a number of trustees from the United States and from Canada. The number of trustees from Canada shall not be less than the percentage of the NEL of Canada to the total NEL of the United States and Canada, times eleven (or times twelve if the number of trustees has been increased to twelve pursuant to Section 1a of this Article III), rounded up to the nearest whole number. For purposes of this board composition requirement, the management trustee shall be counted as a trustee from Canada if he or she is a Canadian citizen.

b. When the Corporation receives recognition by appropriate regulatory authorities in Mexico as its electric reliability organization, the number of independent trustees will be increased by at least one, and the board composition requirement in subsection (a) will be expanded to include Mexico.

Section 3 — Independent Board Members — The independent trustees shall be elected, shall have the qualifications specified, and shall serve in the manner provided in this section.

a. An independent trustee is a person (i) who is not an officer or employee of the Corporation, 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.

b. Independent trustees shall be elected to terms expiring at the annual election of independent trustees occurring in the third year after their election. As of the original effective date of these Bylaws, the independent trustees of the Corporation and the date the term of each independent trustee expires were as follows:

Name	**Term Expires**
John Q. Anderson	2007
Paul F. Barber	2008
Thomas W. Berry	2007
Richard Drouin	2009
James M. Goodrich	2008
Donald P. Hodel	2008
Sharon L. Nelson	2007
Bruce A. Scherr	2009
Kenneth G. Peterson	2009
Fred Gorbet	2008

c. Independent trustees shall be nominated and elected pursuant to the nomination and election procedures specified in Sections 4, 5, and 6 of this Article III.

Section 4 — Vacancies on the Board —Should any vacancy on the board arise from the death, resignation, retirement, disqualification, or removal from office of any independent trustee, or from any other cause, such vacancy shall be filled by electing a trustee at the next annual election of trustees to fill the remainder, if any, of the term of the departed trustee. Provided, that the board by resolution may in its discretion call a special election to fill any such vacancy for the remainder, if any, of the term of the departed trustee. Any vacancy shall be filled so as to maintain the composition of the board in accordance with country participation pursuant to Section 2 of this Article III.

Section 5 — Nominating Committee — The board shall appoint, on an annual basis, or more frequently if needed in the event of a special election pursuant to Article III, Section 4, a nominating committee (the "nominating committee") to recommend candidates (i) to succeed the independent trustees whose terms expire during the current year and (ii) to serve the remainder of the term of any independent trustee who ceased to serve as a trustee subsequent to the last annual election of trustees. The nominating committee shall 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, provided, that the nominating committee shall be chaired by an independent trustee whose term does not expire during the current year and shall include at least three persons who are also members of the Member Representatives Committee, and provided further, that the nominating committee formed for the purpose of recommending candidates to stand for election as trustees at the election to be held on or about February 1, 2007, pursuant to Article III, Section 6 shall not include any members of the Member Representatives Committee but shall include three

persons each of whom at the time of his or her appointment by the chair of the Stakeholders Committee of the North American Electric Reliability Council to the nominating committee shall be a member of that Stakeholders Committee. The board shall establish, by resolution, the procedures to be followed by the nominating committee in identifying and recommending candidates to serve as independent trustees; provided, however, that such procedures shall include a means of permitting members of the Corporation to recommend to the nominating committee candidates for consideration as nominees for independent trustees. The nominating committee shall nominate candidates for election to the board consistent with the requirements of Article III, Section 2 for board composition by country participation, and 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 operation issues; and reflects geographic diversity.

Section 6 — Election of Independent Trustees — The Member Representatives Committee of the Corporation shall elect the persons (i) to succeed those independent trustees whose terms expire each year and (ii) to serve the remainder of the term of any independent trustee who ceased to serve as a trustee subsequent to the last annual election of independent trustees. The annual election of independent trustees shall be scheduled to be conducted on or about February 1 of each year or as soon thereafter as is reasonably possible. Any special election pursuant to Article III, Section 2 shall be held as expeditiously as possible consistent with the time required for a nominating committee to be appointed and to nominate one or more candidates for the special election. All independent trustees shall be elected from nominees proposed by the nominating committee. A nominee shall be elected an independent trustee if such person receives the affirmative vote of two-thirds of the members of the Member Representatives Committee. Each nominee receiving the necessary two-thirds vote of the Member Representatives Committee shall take office immediately upon election. In the event that the voting fails to elect a nominee to fill any of the positions of independent trustee to be filled in an annual election of independent trustees, the nominating committee shall as promptly as reasonably possible consider and propose one or more additional nominee or nominees for that position, and a vote by the Member Representatives Committee on the election of such nominee or nominees shall be conducted as quickly as possible. For avoidance of doubt, the independent trustees shall be elected by the Member Representatives Committee in accordance with this Section 6 and shall not be elected by vote of the members of the Corporation.

Section 7 — Management Trustee — The president of the Corporation shall be, ex officio, the management trustee of the Corporation, effective as of the date of his or her election by the board as president of the Corporation in accordance with Article VI, Section 1, of these Bylaws, to serve until such time that he or she ceases to hold the position of president.

Section 8 — Committees of the Board — The board shall by resolution create and appoint all committees of the board as the board deems necessary to perform its responsibilities; provided, that the management trustee shall not be a member of the audit committee or of the human resources committee, if any. All committees of the board shall have such duties as are prescribed by the board. Notice to the public of the dates, places, and times of meetings of

board committees, and all nonconfidential material provided to committee members, shall be posted on the Corporation's Web site within 24 hours of the time that notice is given to committee members. Meetings of board committees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity.

ARTICLE IV
Meetings of Members of the Corporation

Section 1 — Meetings of Members — Meetings of members of the Corporation may be called for any purpose or purposes by the chairman of the board or by a number of members constituting at least ten (10) percent of the members on the roster of members maintained by the secretary of the Corporation, which number shall include members in at least three of the sectors. Meetings of members shall be held at the principal office of the Corporation or at such other place fixed by the board as shall be specified in the notice of meeting. Meetings shall be called upon written notice of the time, date, place, and purposes of the meeting given to all members on the roster of members maintained by the secretary of the Corporation not less than ten (10) nor more than sixty days (60) prior to the date of the meeting.

Section 2 — Quorum and Voting Requirements for Meetings of Members — At any meeting of the members of the Corporation, attendance in person or by proxy by one-half of the members in each of at least two-thirds of the sectors on the roster of members maintained by the secretary of the Corporation shall constitute a quorum. Except as otherwise expressly provided in the Corporation's Certificate of Incorporation, these Bylaws or applicable law, actions by the members of the Corporation shall be approved upon receipt of seven affirmative votes at a meeting of the members of the Corporation at which a quorum is present, where (i) each sector of the Corporation shall have one vote, except that if less than one-half of the members in a sector are present, in person or by proxy, at the meeting, the vote of that sector shall be weighted by a percentage equal to the number of members of the sector present in person or by proxy at the meeting divided by one-half of the members in the sector; (ii) the vote of each sector of the Corporation shall be allocated for and against the proposed action based on the respective percentages of votes cast for and against the proposed action by the members in that sector voting in person or by proxy; and (iii) the proportions of the votes of each sector allocated for and against the proposed action shall be summed to determine the total number of votes for and against the proposed action.

Section 3 — Waivers of Notice of Meetings of Members; and Member Meeting Adjournments — Notice of a meeting of members need not be given to any member who signs a waiver of notice, in person or by proxy, whether before or after the meeting. The attendance of any member at a meeting, in person or by proxy, without protesting prior to the conclusion of the meeting the lack of notice of such meeting, shall constitute a waiver of notice of the meeting by such member. When any meeting of members is adjourned to another time or place, it shall not be necessary to give notice of the adjourned meeting if the time and place to which the meeting is adjourned are announced at the meeting at which the

adjournment is taken, and if at the adjourned meeting only such business is transacted as might have been transacted at the original meeting.

Section 4 — Action Without a Meeting of Members — Any action, required or permitted to be taken at a meeting of members, may be taken without a meeting if the action is consented to in writing by the minimum number of members that would be required to approve the action at a meeting of the members at which all members were present. The call for action without a meeting of members may be initiated by the chairman of the board or by a number of members constituting at least ten (10) percent of the members on the roster of members maintained by the secretary of the Corporation, which number shall include members in at least three of the sectors. Notice of the proposal for action without a meeting shall be provided to all members on the roster of members maintained by the secretary of the Corporation at least ten (10) days prior to the date established for the tabulation of consents.
The members shall receive written notice of the results, and the results shall be posted on the Corporation's Web site, within ten (10) days of the action vote, and all written responses of the members shall be filed with the minutes of proceedings of members.

Section 5 — Meetings of the Members to be Open — Notice to the public of the dates, places, and times of meetings of the members, and all nonconfidential material provided to the members, shall be posted on the Corporation's Web site within 24 hours of the time that notice is given to the members. Meetings of the members shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity.

ARTICLE V
Meetings of the Board of Trustees

Section 1 — Regular Meetings of the Board — A regular meeting of the board for such business as may come before the meeting shall be held on or about February 1 of each year. By resolution adopted at any meeting of the board, the board may provide for additional regular meetings that may be held without further notice to the trustees.

Section 2 — Special Meetings of the Board — Special meetings of the board for any purpose or purposes may be called at any time by the chairman or by any two trustees. Such meetings may be held upon notice given to all trustees not less than five (5) days prior to the date of the meeting unless the meeting is a closed session as permitted by Article V, Section 4 of these Bylaws, in which event the notice shall be provided to all trustees not less than 24 hours prior to the date and time of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, telegraph, or other electronic media, or by express delivery.

Section 3 — Quorum and Voting Requirements for Meetings of the Board — Unless otherwise expressly provided in the Corporation's Certificate of Incorporation, these Bylaws or applicable law, (i) the quorum necessary for the transaction of business at meetings of the board shall be a majority of the trustees, and (ii) actions by the board shall be approved upon

receipt of the affirmative vote of a majority of the trustees present and voting at a meeting at which a quorum is present.

Section 4 — Meetings of the Board to be Open — Notice to the public of the dates, places, and times of meetings of the board, and all nonconfidential material provided to the board, shall be posted on the Corporation's Web site, and notice of meetings of the board shall be sent electronically to members of the Corporation, within 24 hours of the time that notice or such material is given to the trustees. Meetings of the board shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the board may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity. Any or all of the trustees, or members of a committee, may participate in a meeting of the board, or a meeting of a committee, by means of a communications system by which all persons participating in the meeting are able to hear each other.

Section 5 — Waivers of Notice of Board Meetings; and Board Meeting Adjournments — Notice of a board meeting need not be given to any trustee who signs a waiver of notice, in person or by proxy, whether before or after the meeting, or who attends the meeting without protesting, prior to the conclusion of the meeting, the lack of notice of such meeting. Notice of an adjourned board meeting need not be given if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if the period of adjournment does not exceed ten (10) days.

Section 6 — Action Without a Meeting — Any action, required or permitted to be taken at a meeting of the board or of any committee thereof, may be taken by the board or by the committee without a meeting if the action is consented to in writing by the number of trustees or members of the committee, as the case may be, entitled to vote on the action that would be required to approve the action at a meeting of the board or committee with all members of the board or committee present. The call for action without a meeting of the board may be initiated by the chairman or by any two trustees. Notice of the proposed call for action without a meeting, and all nonconfidential material provided to the board in connection with the call for action without a meeting, shall be posted on the Corporation's Web site within 24 hours of the time notice of the call for action without a meeting or such material is provided to the board. The call for action without a meeting of a committee of the board may be initiated by the chairman or by any two members of the committee. The trustees or members of the committee shall receive written notice of the results, and unless the action was confidential the results shall be posted on the Corporation's Web site, within seven (7) days of the action vote. All written responses of the trustees shall be filed with the minutes of the Corporation, and all written responses of members of a committee shall be filed with the minutes of such committee.

ARTICLE VI
Officers

Section 1 — Officers — At its regular meeting held on or about February 1 of each year in

accordance with Section 1 of Article V of these Bylaws, the board shall elect a chairman, a vice chairman, a president, a secretary, a treasurer, an assistant secretary-treasurer, and such other officers of the Corporation (collectively, the "officers") as it shall deem necessary. The chairman and the vice chairman must each be independent trustees prior to their election to such offices. The chairman, vice chairman, and president shall each be nominated and elected by the board. All of the remaining officers shall be appointed or removed by the board based upon the recommendation of the president. The duties and authority of the chairman, the vice chairman, and the president shall be determined from time to time by the board, and the duties and authority of the other officers of the Corporation shall be determined from time to time by the president. Subject to any such determination, the officers shall have the following duties and authority:

a. The chairman shall preside at all meetings of the members and at all meetings of the board. The chairman, in consultation with the other trustees, shall be responsible for the efficient operation of the board and its committees. The chairman shall be an ex officio member of each committee of the board. The chairman may delegate from time to time any or all of the aforesaid duties and authority to the vice chairman, another trustee, the president, or any other officer.

b. The vice chairman shall have such duties and possess such other powers as may be delegated to him or her by the chairman. The vice chairman shall act as the chairman at such times as the chairman may request. In the event the chairman is unable to discharge the duties and powers of that office by reason of incapacity and during any vacancies in the office of the chairman, the vice chairman shall act as chairman until the cessation of such incapacity or the filling of such vacancy.

c. The president shall be the chief executive officer of the Corporation. He or she shall be responsible for the day-to-day ongoing activities of the Corporation and shall have such other duties as may be delegated or assigned to him or her by the chairman. The president may enter into and execute in the name of the Corporation contracts or other instruments not in the regular course of business that are authorized, either generally or specifically, by the board.

d. The secretary shall maintain the roster of members of the Corporation; shall cause notices of all meetings to be served as prescribed in these Bylaws; shall keep or cause to be kept the minutes of all meetings of the members and the board; and shall have charge of the seal of the Corporation. The secretary shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the president.

e. The treasurer shall have custody of the funds and securities of the Corporation, and shall keep or cause to be kept regular books of account for the Corporation. The treasurer shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the president.

f. The assistant secretary-treasurer shall have such duties and possess such other powers as may be delegated to him or her by the president.

ARTICLE VII
Committees of the Corporation

Section 1 — Committees of the Corporation — In addition to those committees specified by these Bylaws, to which the board shall appoint members in accordance with the requirements of these Bylaws, the board may by resolution create standing committees of the Corporation; and may in addition by resolution appoint such other committees as the board deems necessary to carry out the purposes of the Corporation. The board shall appoint standing committees and other committees of the Corporation that are representative of members, other interested parties and the public, that provide for balanced decision making, and that include persons with outstanding technical knowledge and experience. All appointments of committees of the Corporation shall provide the opportunity for an equitable number of members from the United States and Canada (and from Mexico after the Corporation receives recognition by appropriate governmental authorities in Mexico as its electric reliability organization) to be appointed to each committee in approximate proportion to each country's percentage of the total NEL. All committees shall have such scope and duties, not inconsistent with law, as are specified in these Bylaws and the Rules of Procedure of the Corporation or otherwise determined by the board.

ARTICLE VIII
Member Representatives Committee

Section 1 — Member Representatives Committee — The Corporation shall have a Member Representatives Committee that shall have the following rights and obligations:

a. to elect the independent trustees, in accordance with Article III, Section 6;

b. to vote on amendments to the Bylaws, in accordance with Article XIV; and

c. to provide advice and recommendations to the board with respect to the development of annual budgets, business plans and funding mechanisms, and other matters pertinent to the purpose and operations of the Corporation.

Because it is elected by the members of the Corporation and not appointed by the board, the Member Representatives Committee shall not be a standing committee of the Corporation, but is authorized to provide its advice and recommendations directly to the board.

Section 2 — Composition of the Member Representatives Committee — The Member Representatives Committee shall consist of (i) two representatives from each sector except the government representative sector and the regional entity sector, (ii) two voting representatives from the regional entity sector, with the remaining members of that sector being non-voting

members of the Member Representatives Committee, (iii) the chairman and vice chairman of the Member Representatives Committee, (iv) any additional Canadian representatives as are selected pursuant to Section 4 of this Article VIII, and (v) 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 Member Representatives Committee except the two representatives of state governments. The representatives of each sector shall be members of the Corporation, or officers or executive-level employees, agents or representatives of members of the Corporation, in that sector; provided, that at any time only one officer, employee, agent, or representative of a member in a sector may be a representative from that sector. No member of the board shall be a member of the Member Representatives Committee. The board may by resolution create additional nonvoting positions on the Member Representatives Committee at the written request of any group of members of the Corporation that believes its interests are not adequately represented on the Member Representatives Committee.

In order to provide that the terms of approximately one-half of the members of the Member Representatives Committee expire each year, on the initial Member Representatives Committee one-half of the representatives from each sector shall serve a term expiring at the next annual meeting, and one-half of the representatives from each sector shall serve a term expiring at the second succeeding annual meeting, in each case held pursuant to Section 7 of this Article VIII.

Following the expiration of the terms of the members of the initial Member Representatives Committee as provided above, each member of the Member Representatives Committee shall thereafter serve a term of two years commencing at an annual meeting held pursuant to Section 7 of this Article VIII and ending at the second succeeding annual meeting. There shall be no limit on the number of terms that a member of the Corporation, or an employee, agent, or representative of a member of the Corporation, may serve on the Member Representatives Committee.

Section 3 — Election of Members of the Member Representatives Committee

a. Unless a sector adopts an alternative election procedure, the annual election of representatives from each sector to the Member Representatives Committee, and any election to fill a vacancy, shall be conducted in accordance with the following process, which shall be administered by the officers of the Corporation. During the period beginning approximately ninety (90) days and ending approximately thirty (30) days prior to an annual election, or beginning approximately forty-five (45) days and ending approximately fifteen (15) days prior to an election to fill a vacancy, nominations may be submitted for candidates for election to the Member Representatives Committee, provided that for the initial election the period may begin as soon as these bylaws are made effective and may end approximately fifteen (15) days prior to the election. A nominee for election as a sector representative must be a member, or an officer, executive-level employee or agent of a member, in that sector. No more than one nominee who is an officer, executive-level employee

or agent of a member or its affiliates may stand for election in any single sector; if more than one officer, employee or agent of a member or its affiliates is nominated for election from a sector, the member shall designate which such nominee shall stand for election. The election of representatives shall be conducted over a period of ten (10) days using an electronic process. Each member in a sector shall have one vote for each representative to be elected from the sector in that election, and may cast no more than one vote for any nominee. The nominee receiving the highest number of votes in each sector shall be elected to the representative position to be filled from that sector; if there is more than one representative position to be filled from a sector, the nominee receiving the second highest number of votes shall also be elected, and so forth. Provided, that to be elected a nominee must receive a number of votes equal to a simple majority of the members in the sector casting votes in the election. If no nominee in a sector receives a simple majority of votes cast in the first ballot, a second ballot shall be conducted which shall be limited to the number of candidates receiving the two (2) highest vote totals on the first ballot (or to the number of candidates receiving the four (4) highest vote totals on the first ballot if two representative positions remain to be filled, and so forth). The nominee or nominees receiving the highest total or totals of votes on the second ballot shall be elected to the representative position or positions remaining to be filled for the sector.

A sector may adopt an alternative procedure to the foregoing to nominate and elect its representatives to the Member Representatives Committee if (i) the alternative procedure is consistent in principle with the procedures specified in the preceding paragraph of this Section 3a, and (ii) the alternative procedure is approved by vote of at least two-thirds of the members in the sector. Any alternative procedure is subject to review and disapproval by the board.

Section 4 — Adequate Representation of Canadian Interests on the Member Representatives Committee — In addition to the requirements for composition of the Member Representatives Committee specified in Section 1 of this Article VIII, the Member Representatives Committee shall contain a number of Canadian voting representatives equal to the percentage of the NEL of Canada to the total NEL of the United States and Canada, times the total number of voting members on the Member Representatives Committee, rounded up to the next whole number. If the annual selection of members of the Member Representatives Committee pursuant to Section 3 of this Article VIII does not result in the number of Canadian voting representatives provided for herein on the Member Representatives Committee, then the candidate who received the highest fraction of the sector vote among those candidates who would have qualified as Canadian voting representatives but were not elected to the Member Representatives Committee shall be added to the Member Representatives Committee. Additional Canadian voting representatives shall be added to the Member Representatives Committee through this selection process until the Member Representatives Committee includes a number of Canadian voting representatives equal to the percentage of the NEL of Canada to the total NEL of the United States and Canada, times the total number of voting members on the Member Representatives Committee, rounded up to

the next whole number. Provided, that no more than one such additional Canadian voting representative shall be selected from a sector, except that if this limitation precludes the addition of the number of additional Canadian voting representatives required by the previous sentence, then no more than two Canadian voting representatives may be selected from the same sector. Such additional Canadian voting representatives shall be representatives of the sectors in which they stood for election, and shall serve terms expiring at the next annual meeting of the Member Representatives Committee pursuant to Section 7 of this Article VIII. For purposes of this Section 4, "Canadian" means one of the following: (a) a company or association incorporated or organized under the laws of Canada or of a province of Canada that is a member of the Corporation, or its designated representative irrespective of nationality; (b) an agency of a federal, provincial, or local government in Canada that is a member of the Corporation, or its designated representative irrespective of nationality; or (c) a person who is a Canadian citizen residing in Canada and is a member of the Corporation.

When the Corporation receives recognition from appropriate governmental authorities in Mexico as the electric reliability organization, this provision will be expanded to provide for adequate representation of Mexican interests on the Member Representatives Committee.

Section 5 — Officers of the Member Representatives Committee — At the initial meeting of the Member Representatives Committee, and annually thereafter prior to the annual election of representatives to the Member Representatives Committee, the Member Representatives Committee shall select a chairman and vice chairman from among its voting members by majority vote of the members of the Member Representatives Committee to serve as chairman and vice chairman of the Member Representatives Committee during the upcoming year; provided, that the incumbent chairman and vice chairman shall not vote or otherwise participate in the selection of the incoming chairman and vice-chairman. The newly selected chairman and vice chairman shall not have been representatives of the same sector. Selection of the chairman and vice chairman shall not be subject to approval of the board. The chairman and vice chairman, upon assuming such positions, shall cease to act as representatives of the sectors that elected them as representatives to the Member Representatives Committee and shall thereafter be responsible for acting in the best interests of the members as a whole.

Section 6 — Vacancies on the Member Representatives Committee — In the event that any member of the Member Representatives Committee ceases to serve as a member of the Member Representatives Committee as a result of his or her death, resignation, retirement, disqualification, or removal or other cause, the members in the sector of which such member was a representative shall elect, as soon thereafter as reasonably possible, and in accordance with the procedures in Sections 3 and 4 of this Article VIII, a new member to replace the member of the Member Representatives Committee who ceases to serve. Except with regard to the selection of the chairman and vice chairman at the initial meeting of the Member Representatives Committee, the vacancies in the sector representatives created by the selection of the chair and vice chair pursuant to Section 5 of this Article VIII shall be filled at the annual election of representatives to the Member Representatives Committee that is next held following the election of the chairman and vice chairman. In the case of the selection of the chairman and vice chairman at the initial meeting of the Member Representatives

Committee, the sector representative vacancies created thereby shall be filled as soon thereafter as reasonably possible in accordance with the procedures in Section 3 of this Article VIII for sector representative vacancies.

Section 7 — Annual Meeting of the Member Representatives Committee — An annual meeting of the Member Representatives Committee for the election of independent trustees and to conduct such other business as may come before the meeting shall be held on or about February 1 of each year or as soon thereafter as is reasonably possible. By resolution adopted at any meeting of the Member Representatives Committee, the Member Representatives Committee may provide for additional regular meetings that may be held without further notice to the members of the Member Representatives Committee.

Section 8 — Special Meetings of the Member Representatives Committee — Special meetings of the Member Representatives Committee for any purpose or purposes may be called by the chair of the Member Representatives Committee or by any five (5) members of the Member Representatives Committee, which number shall include representatives from at least three sectors, and require notice given to all members of the Member Representatives Committee not less than seven (7) days prior to the date of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, telegraph, or other electronic media, or by express delivery.

Section 9 — Quorums and Voting for Meetings of the Member Representatives Committee — The quorum necessary for the transaction of business at meetings of the Member Representatives Committee shall be two-thirds of the voting members of the Member Representatives Committee attending the meeting in person or by proxy. A member of the Member Representatives Committee may give a proxy only to a person who is a member, or an officer, executive-level employee, agent or representative of a member, registered in the same sector. Each voting member of the Member Representatives Committee shall have one (1) vote on any matter coming before the Member Representatives Committee that requires a vote. Except as otherwise expressly provided in the Corporation's Certificate of Incorporation, these Bylaws or applicable law, actions by members of the Member Representatives Committee shall be approved upon receipt of the affirmative vote of a majority of the voting members of the Member Representatives Committee present and voting, in person or by proxy, at any meeting at which a quorum is present.

Section 10 — Meetings of the Member Representatives Committee to be Open — Notice to the public of the dates, places, and times of meetings of the Member Representatives Committee, and all nonconfidential material provided to the Member Representatives Committee, shall be posted on the Corporation's Web site, and notice of meetings of the Member Representatives Committee shall be sent electronically to all members of the Corporation, within 24 hours of the time that notice or such material is given to the Member Representatives Committee. Meetings of the Member Representatives Committee shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the Member Representatives Committee may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity. Any or all members of, and any other

participants in, the Member Representatives Committee may participate in a meeting of the Member Representatives Committee by a means of a communications system by which all persons participating in the meeting are able to hear each other.

Section 11 — Waivers of Notice of Meetings of the Member Representatives Committee; and Meeting Adjournments — Notice of a meeting of the Member Representatives Committee need not be given to any member of the Member Representatives Committee who signs a waiver of notice, in person or by proxy, whether before or after the meeting, or who attends the meeting without protesting, prior to the conclusion of the meeting, the lack of notice of such meeting. Notice of an adjourned meeting of the Member Representatives Committee need not be given if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if the period of adjournment does not exceed ten (10) days.

Section 12 — Action Without a Meeting of the Member Representatives Committee — Any action required or permitted to be taken at a meeting of the Member Representatives Committee may be taken by the Member Representatives Committee without a meeting if the action is consented to in writing by the number of members of the Member Representatives Committee entitled to vote on the action that would be required to approve the action at a meeting of the Member Representatives Committee with all of its members present. The call for action without a meeting of the Member Representatives Committee may be initiated by the Chair of the Member Representatives Committee or by any five (5) members of the Member Representatives Committee, which number shall include representatives from at least three (3) sectors. Notice of the proposed call for action without a meeting, and all nonconfidential material provided to the Member Representatives Committee in connection with the call for action without a meeting, shall be posted on the Corporation's Web site within 24 hours of the time notice of the call for action without a meeting or such material is provided to the members of the Members Representative Committee. The members of the Member Representatives Committee shall receive written notice of the results, and the results shall be posted on the Corporation's Web site, within seven (7) days of the action vote, and all written responses of voting members of the Member Representatives Committee shall be filed with the minutes of the Corporation.

Section 13 — Other Procedures of the Member Representatives Committee — The chairman of the board in office on November 1, 2006, shall preside at the initial meeting of the Member Representatives Committee, until a chairman is selected in accordance with Section 5 of this Article VIII. Except as to any matter as to which the procedure to be followed by the Member Representatives Committee is expressly set forth in these Bylaws, the Member Representatives Committee may adopt such additional procedures, not inconsistent with these Bylaws, as it deems appropriate.

ARTICLE IX
Reliability Standards

Section 1 — Development of Reliability Standards — The Corporation shall develop, implement and, in all regions in which necessary governmental approvals have been obtained or authority has been provided, enforce, reliability standards that provide for reliable operation of the bulk power systems of North America. All reliability standards shall be approved by the board. All reliability standards of the Corporation shall be posted on its Web site. Nothing in this Article shall be deemed to invalidate any standard of the Corporation that was in effect on November 1, 2006.

Section 2 — Procedures for Development of Reliability Standards —The Corporation shall develop reliability standards pursuant to procedures and processes that shall be specified in the Rules of Procedure of the Corporation. The Rules of Procedure shall provide for the development of reliability standards through an open, transparent, and public process that provides for reasonable notice and opportunity for public comment, due process, and balancing of interests and is designed to result in reliability standards that are technically sound. Participation in the process for development of 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 bulk power system.

Section 3 — Procedures for Determinations of Violations of Reliability Standards and Imposition of Sanctions for Violations — In all regions in which regulatory approval has been obtained or governmental authority has been provided, the Corporation shall consider and make determinations that an owner, operator, or user of the bulk power system has violated a reliability standard, and shall impose sanctions for such violations, pursuant to procedures and processes that shall be specified in the Rules of Procedure of the Corporation. Such procedures and processes shall provide for reasonable notice and opportunity for hearing. Any sanction imposed for a violation of a reliability standard shall bear a reasonable relation to the seriousness of the violation and shall take into consideration efforts of the owner, operator, or user of the bulk power system to remedy the violation in a timely manner. Subject to any necessary action by any applicable governmental authorities, no sanction imposed for a violation of a reliability standard shall take effect until the thirty-first (31) day after the Corporation, where authorized by law or agreement, files with the Commission or other applicable governmental authority notice of the sanction and the record of the proceedings in which the violation and sanction were determined, or such other date as ordered by the Commission or other applicable governmental authority or as prescribed by applicable law.

ARTICLE X
Agreements with Regional Entities

Section 1 — Delegation Agreements with Regional Entities — The Corporation may, in accordance with appropriate governmental authority, enter into agreements with regional entities pursuant to which a regional entity shall be delegated the authority of the Corporation to enforce reliability standards within a geographic region of North America and may develop and propose reliability standards to be in effect within such region. All delegation agreements with regional entities shall be approved by the board. No delegation agreement

with a regional entity shall be effective with respect to a region until the agreement has received any necessary approval from an applicable governmental authority.

Section 2 — Standards for Delegation Agreements — The Corporation shall be permitted to enter into a delegation agreement with a regional entity only if the board determines that (i) the regional entity has agreed to promote, support, and comply with the purposes and policies of the Corporation as set forth in its Certificate of Incorporation, Bylaws, Rules of Procedure, and Reliability Standards as from time to time adopted, approved, or amended; (ii) the regional entity satisfies the criteria set forth in Sections 39.3(b) and 39.8 of the Commission's regulations, or other criteria specified by applicable governmental authorities, and (iii) the delegation agreement will promote effective and efficient administration of the reliability of the bulk power system.

ARTICLE XI
Rules of Procedure

Section 1 — Development of Rules of Procedure — The Corporation shall develop and implement such Rules of Procedure as in the judgment of the board are necessary or appropriate to carry out the purposes of the Corporation and to govern its operations, including without limiting the foregoing, Rules of Procedure relating to (i) registration of owners, operators, and users of the bulk power system; (ii) development of reliability standards; (iii) procedures for standing committees of the Corporation, subgroups of standing committees, and other committees, subcommittees, task forces, and sector-specific forums of the Corporation; (iv) critical infrastructure protection; (v) conduct of readiness evaluations and reliability assessments; (vi) enforcement of compliance with reliability standards and determinations of violations of reliability standards by owners, operators, and users of the bulk power system; (vii) impositions of sanctions for violations of reliability standards; (viii) development, implementation, and administration of delegation agreements with regional entities; (ix) personnel certification; (x) event analysis and information exchange; (xi) realtime monitoring of the bulk power system; and (xii) development and administration of budgets, business plans, and funding mechanisms of the Corporation. All Rules of Procedure of the Corporation shall be posted on its Web site.

Section 2 — Adoption, Amendment, and Repeal of Rules of Procedure — Except as provided in Section 2 of Article XII, all Rules of Procedure, amendments thereto and repeals thereof shall be approved by the board. Proposals to adopt new Rules of Procedure or to amend or repeal existing Rules of Procedure may be submitted by (i) the Member Representatives Committee, (ii) any fifty (50) members of the Corporation, which number shall include members in at least three sectors, (iii) a committee of the Corporation to whose purpose and functions the Rule of Procedure pertains, or (iv) an officer of the Corporation. Unless the board determines that exigent conditions exist requiring adoption of a new Rule of Procedure or amendment or repeal of an existing Rule of Procedure in a shorter time, all proposals for adoption, amendment and repeal of Rules of Procedure shall be posted on the Corporation's Web site and subject to public comment for a minimum of forty-five (45) days prior to action by the board. All Rules of Procedure and amendments to and repeals of Rules of Procedure approved by the board shall be submitted to the Commission and to other

applicable governmental authorities for approval, and shall not be effective in the United States until approved by the Commission or in Canada or Mexico until approval is obtained from any governmental authority from which approval is required in those countries and subject to any conditions, limitations, or modifications required by the Commission or other governmental authority. Nothing in this Article shall be deemed to invalidate any Rule of Procedure of the Corporation that was in effect on November 1, 2006.

ARTICLE XII
Personnel Certification Governance Committee

Section 1 — Personnel Certification Governance Committee — There shall be a Personnel Certification Governance Committee of the Corporation, which shall be a standing committee of the Corporation. The purpose of the Personnel Certification Governance Committee shall be to provide oversight to the policies and processes used to implement and maintain the integrity and independence of the Corporation's System Operator Certification Program. The governance authority and structure of the Personnel Certification Governance Committee shall be implemented and maintained so that policies and procedures are established to protect against undue influence that could compromise the integrity of the System Operator Certification process.

Section 2 — Appointment and Reporting of the Personnel Certification Governance Committee — The members of the Personnel Certification Governance Committee shall be appointed by the board from candidates selected and presented by a nominating task force in accordance with Rules of Procedure for the Personnel Certification Governance Committee. Nominations and appointments shall take into account the need to include representatives of all geographic regions of North America on the Personnel Certification Governance Committee. The Personnel Certification Governance Committee shall report directly to the board and the president of the Corporation regarding governance and administration of the System Operator Certification Program; provided, however, that the Personnel Certification Governance Committee shall have autonomy in developing and implementing system operator certification eligibility requirements, the development, administration, and scoring of the system operator assessment instruments, and operational processes for the System Operator Certification Program. The Personnel Certification Governance Committee shall provide to the board periodic assessments, no less frequently than every two (2) years, of the effectiveness of the System Operator Certification Program.

Section 3 — Administration of the Personnel Certification Governance Committee — In order to maintain the independence of the Personnel Certification Governance Committee, staff of the Corporation shall administer the System Operator Certification program on behalf of the Personnel Certification Governance Committee on a fee for service basis.

ARTICLE XIII
Budgets and Funding

Section 1 — Compensation of the Board and Member Representatives Committee — The board shall have the right to fix from time to time, by resolution adopted by a majority of the independent trustees then serving as trustees, the amount of the annual retainer fee or other compensation to be paid to the independent trustees for their services to the Corporation, including any fees to be paid for each meeting of the board or any board committee attended by an independent trustee. No compensation shall be paid to the management trustee for his or her services on the board, other than the compensation paid to the management trustee for services as president of the Corporation. No compensation shall be paid by the Corporation to the members of the Member Representatives Committee for their services on the Member Representatives Committee.

Section 2 — Preparation and Adoption of Annual Budget, Business Plan, and Funding Mechanism — The board shall prepare or cause to be prepared an annual budget for the administrative and other expenses of the Corporation, including the expenditures for the fiscal year for any material special projects undertaken by the Corporation and reasonable and proper reserves and provisions for contingencies, an accompanying business plan for the Corporation, and a funding mechanism, for each fiscal year. The annual budget, business plan, and funding mechanism of the Corporation shall be for a fiscal year commencing on January 1 and ending on December 31. Each annual budget, business plan, and funding mechanism (including the annual budget, annual business plan, and annual funding mechanism for each regional entity) shall be approved by the board at a regular meeting or a special meeting of the board duly called for that purpose. The board shall approve each annual budget, business plan, and funding mechanism at least 135 days before the start of the fiscal year in order to allow for timely submittal of the approved annual budget, business plan, and funding mechanism to the applicable governmental authorities.

Section 3 — Criteria for Funding Mechanisms — The annual funding mechanism shall be designed to recover, over the course of the fiscal year, the sum of (i) the annual budget, (ii) less revenues projected to be received by the Corporation from other sources such as sales of services and materials and registration, application and certification fees for programs conducted or administered by the Corporation, and (iii) plus or minus the estimated deficiency or excess of the Corporation's revenues compared to its expenditures for the current fiscal year. The annual funding mechanism shall consist of such assessments as determined by the 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.

Section 4 — Consultation in Preparation of Annual Budget, Business Plan, and Funding Mechanism — In preparing the annual budget, business plan, and funding mechanism, the board shall consult with the members of the Member Representatives Committee, and shall post a draft budget and business plan for review and comment by the members of the Corporation and the Member Representatives Committee and the standing committees of the Corporation for at least thirty (30) days prior to the date of the meeting of the board at which the annual budget, business plan, and funding mechanism are to be adopted.

Section 5 — Modified or Supplemental Funding Mechanisms — During the course of a fiscal year, the board may modify the approved funding mechanism or develop and approve a supplemental funding mechanism if determined by the board to be necessary due to such factors as a shortfall in revenues of the Corporation from projected levels, incurred or anticipated expenditures or new projects not provided for in the annual budget, or such other factors as in the judgment of the board warrant modification of the funding mechanism for the fiscal year or development of a supplemental funding mechanism. In preparing a modified or supplemental funding mechanism, the board shall follow the provisions of Section 4 of this

Article XIII to the extent possible in the judgment of the board in light of the exigency of the circumstances necessitating preparation and approval of the modified or supplemental funding mechanism. Each modified or supplemental funding mechanism shall be approved by the board at a regular meeting or a special meeting of the board duly called for that purpose.

Section 6 — Submission of Annual Budgets, Business Plans, and Funding Mechanisms to the Governmental Authorities — Each annual budget, annual business plan, and annual, modified, or supplemental funding mechanism approved by the board (including the annual budget, annual business plan, and annual, modified, or supplemental funding mechanism for each regional entity) shall be submitted by the Corporation to the applicable governmental authorities for approval in accordance with its regulations, except as otherwise provided by applicable law or by agreement, and shall not be effective until it has received any necessary approval by the applicable governmental authorities. If a governmental authority by order modifies or remands an annual budget, business plan, or annual, modified, or supplemental funding mechanism, the board shall promptly following such order adopt such modifications to the budget, business plan, or funding mechanism as are required or directed by the order of the governmental authority.

ARTICLE XIV
Amendments to the Bylaws

Section 1 — Amendments to the Bylaws — These Bylaws may be altered, amended, or repealed by a majority vote of both the board and the Member Representatives Committee at respective meetings of the board and the Members Representative Committee at which a quorum is present. Written notice of the subject matter of the proposed changes to the Bylaws shall be provided, as appropriate, to the trustees or to the Member Representatives Committee not less than ten (10) nor more than sixty (60) days prior to the date of the meeting of the board or of the Member Representatives Committee at which the vote is to be taken. Notwithstanding the provisions of this Article XIV, the members of the Corporation voting by sector shall have the right to alter, amend, or repeal Bylaws adopted by the board and the Member Representatives Committee and to adopt new Bylaws, provided that any such alteration, amendment, or repeal or the adoption of new Bylaws is approved by vote of two-thirds of the sectors at a meeting of Members called for that purpose, or by written consent of two-thirds of the sectors, where the number of votes for and against the proposed alteration, amendment, repeal, or adoption of Bylaws shall be determined in accordance with Section 2 of Article IV. Any alteration, amendment, repeal, or adoption of Bylaws shall be subject to

any applicable requirements for filing with or approval by the Commission and any other applicable governmental authority.

ARTICLE XV
General

Section 1 — Indemnification — The Corporation shall indemnify its officers, trustees and other corporate agents to the full extent from time to time permitted by the New Jersey Nonprofit Corporation Act and other applicable law. Such right of indemnification shall inure to the benefit of the legal representative of any such person. The foregoing indemnification shall be in addition to, and not in restriction or limitation of, any privilege or power that the Corporation may have with respect to the indemnification or reimbursement of its trustees, officers, or other corporate agents. The Corporation shall also pay or advance expenses incurred by an officer, trustee, or other corporate agent in connection with a proceeding in advance of the final disposition of the proceeding upon receipt of an undertaking by or on behalf of the officer, trustee, or other corporate agent to repay the amount unless it shall be ultimately determined that the officer, trustee, or other corporate agent is entitled to be indemnified by the Corporation.

Section 2 — Parliamentary Rules — In the absence of and to the extent not inconsistent with specific provisions in these Bylaws, meetings or other actions pursuant to these Bylaws shall be governed by procedures that the board may, from time to time, establish by resolution.

Section 3 — Dissolution — Upon dissolution of the Corporation, in accordance with paragraph TENTH of the Certificate of Incorporation, the remaining assets of the Corporation after payment of debts shall be distributed in the manner determined by the board, provided, (i) that no part of the assets shall be distributed to any trustee of the Corporation, and (ii) that the distribution of assets shall be consistent with the requirements of Section 501(c)(6) of the United States Internal Revenue Code of 1986, as amended.

ATTACHMENT 2

Amended North American Electric Reliability Corporation Bylaws – **Redline**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Bylaws

Approved by the Board of Trustees: ~~August 5, 2009~~February 8, 2018 Effective: ~~October 14, 2009~~[Proposed Date]

BYLAWS

OF THE

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ARTICLE I
Definitions

Section 1 — Definitions — As used in these Bylaws of the North American Electric Reliability Corporation (hereinafter referred to as "the Corporation"), the terms set forth in this Article I shall have the meanings set forth herein.

"Applicable governmental authority" means the Federal Energy Regulatory Commission within the United States and the appropriate governmental authority with subject matter jurisdiction over reliability within Canada and Mexico.

"Board" means the Board of Trustees of the Corporation.

"Bulk power system" means facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and 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.

"Commission" means the Federal Energy Regulatory Commission.

"Electric reliability organization" or "ERO" means the organization that is certified by the Commission under Section 39.3 of its regulations, the purpose of which is to establish and enforce Reliability Standards for the bulk power system in the United States. The organization may also have received recognition by applicable governmental authorities in Canada and Mexico to establish and enforce reliability standards for the bulk power systems of the respective countries.

"Member" means a member of the Corporation pursuant to Article II of these Bylaws.

"Net Energy for Load (NEL)" means 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 storage of energy at energy storage facilities. Calculations of net energy for load for all purposes under these Bylaws shall be based on the most recent calendar year for which data on net energy for load of applicable regions of the United States, Canada, and Mexico is available.

"Regional entity" means an entity having enforcement authority pursuant to 18 C.F.R. § 39.8.

"Reliability standard" means a requirement to provide for reliable operation of the bulk power system, including without limiting the foregoing requirements for the operation of existing bulk power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary for reliable operation of the bulk power system, but shall not include any requirement to enlarge bulk power system facilities or to construct new transmission capacity or generation capacity.

"Reliable operation" means operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of the bulk power system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

"Sector" means a group of members of the Corporation that are bulk power system owners, operators, or users or other persons and entities with substantially similar interests, including governmental entities, as pertinent to the purposes and operations of the Corporation and the operation of the bulk power system, as defined in Article II, Section 4 of these Bylaws. Each sector shall constitute a class of members for purposes of the New Jersey Nonprofit Corporation Act.

Section 2 — Additional Defined Terms — Additional terms not defined in this Article I are defined in the remainder of these Bylaws.

Section 3 — Technical Terms — Technical terms not defined in these Bylaws shall have the definitions set forth in the Federal Power Act, Part 39 of the regulations of the Commission, or the "Glossary of Terms Used in Reliability Standards", in that order of precedence, and if not defined in any of those sources, shall be defined in accordance with their commonly understood and used technical meaning in the electric power industry, including applicable codes and standards.

ARTICLE II
Membership

Section 1 — Members — Membership in the Corporation is voluntary and is open to any person or entity that has an interest in the reliable operation of the North American bulk power system and that registers with the Corporation as a member, maintains its registration in accordance with this Article II, and complies with the other conditions and obligations of membership specified in these Bylaws. Membership in a regional entity shall not be a condition for membership in the Corporation. The secretary of the Corporation shall maintain a roster of the members of the Corporation.

Section 2 — Registration as a Member — Any person or entity that is eligible to be a member of the Corporation in accordance with Article II, Section 1 may become a member by completing, and submitting to the secretary of the Corporation, a membership registration on a form prescribed by the board. If not a natural person, the member shall designate a

representative and an alternative representative with authority to receive notices, cast votes, and execute waivers and consents on behalf of the member. The secretary of the Corporation shall maintain a current roster of the members of the Corporation including each member's designated representative and alternative representative. From time to time, the board shall establish a date by which members shall submit their registration renewals. All members shall be required to renew their registrations within 30 calendar days of a request by the secretary of the Corporation, using a registration renewal form prescribed by the board. The secretary of the Corporation shall remove from the roster of members of the Corporation any member that has not submitted a registration renewal within 30 days following a date established by the board. The secretary shall notify any member that is removed from the roster of members of such removal, by notice sent to such former member's last known address on the records of the Corporation.

Section 3 — Obligations and Conditions of Membership

a. Each member shall agree, in writing, to accept the responsibility to promote, support, and comply with the purposes and policies of the Corporation as set forth in its Certificate of Incorporation, Bylaws, Rules of Procedure, and Reliability Standards as from time to time adopted, approved, or amended.

b. As an additional condition of membership in the Corporation, each person or entity registering as a member shall be required to execute an agreement with the Corporation, in a form to be specified by the board, that such person or entity will hold all trustees, officers, employees, and agents of the Corporation, as well as volunteers participating in good faith in the activities of the Corporation, harmless, to the extent permitted by Federal or provincial laws, regulations and rules, for any injury or damage to that member caused by any act or omission of any trustee, officer, employee, agent, or volunteer in the course of performance of his or her duties on behalf of the Corporation, other than for acts of gross negligence, intentional misconduct, or a breach of confidentiality.

Section 4 — Membership Sectors

a. Each member shall elect to be assigned to one of the following membership sectors: (i) investor-owned utility; (ii) state/municipal utility; (iii) cooperative utility; (iv) federal or provincial utility/power marketing administration; (v) transmission-dependent utility; (vi) merchant electricity generator; (vii) electricity marketer; (viii) large end-use electricity customer; (ix) small end-use electricity customer; (x) independent system operator/regional transmission organization; (xi) regional entity; or (xii) government representatives. The composition of each sector shall be as follows:

    i. Investor-owned utility — This sector includes any investor-owned entity with a substantial business interest in ownership and/or operation in any of

the asset categories of generation, transmission or distribution. This sector also includes organizations that represent the interests of such entities.

ii. State/municipal utility — This sector includes any entity owned by or subject to the governmental authority of a state or municipality, that is engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the state or municipality; and any entity, whose members are municipalities, formed under state law for the purpose of generating, transmitting, or purchasing electricity for sale at wholesale to their members. This sector also includes organizations that represent the interests of such entities.

iii. Cooperative utility — This sector includes any non-governmental entity that is incorporated under the laws of the state in which it operates, is owned by and provides electric service to end-use customers at cost, and is governed by a board of directors that is elected by the membership of the entity; and any non-governmental entity owned by and which provides generation and/or transmission service to such entities. This sector also includes organizations that represent the interests of such entities.

iv. Federal or provincial utility/Federal Power Marketing Administration — This sector includes any U.S. federal, Canadian provincial, or Mexican entity that owns and/or operates electric facilities in any of the asset categories of generation, transmission, or distribution; or that functions as a power marketer or power marketing administrator. This sector also includes organizations that represent the interests of such entities.

v. Transmission-dependent utility — This sector includes any entity with a regulatory, contractual, or other legal obligation to serve wholesale aggregators or customers or end-use customers and that depends primarily on the transmission systems of third parties to provide this service. This sector also includes organizations that represent the interests of such entities.

vi. Merchant electricity generator — This sector includes any entity that owns or operates an electricity generating facility that is not included in an investor-owned utility's rate base and that does not otherwise fall within any of sectors (i) through (v). This sector includes but is not limited to cogenerators, small power producers, and all other nonutility electricity producers such as exempt wholesale generators who sell electricity at wholesale. This sector also includes organizations that represent the interests of such entities.

vii. Electricity marketer — This sector includes any entity that is engaged in the activity of buying and selling of wholesale electric power in North America

on a physical or financial basis. This sector also includes organizations that represent the interests of such entities.

viii. Large end-use electricity customer — This sector includes any entity in North America with at least one service delivery taken at 50 kV or higher (radial supply or facilities dedicated to serve customers) that is not purchased for resale; and any single end-use customer with an average aggregated service load (not purchased for resale) of at least 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations that represent the interests of such entities.

ix. Small end-use electricity customer — This sector includes any person or entity within North America that takes service below 50 kV; and any single end-use customer with an average aggregated service load (not purchased for resale) of less than 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations (including state consumer advocates) that represent the interests of such entities.

x. Independent system operator/regional transmission organization — This sector includes any entity authorized by the Commission to function as an independent transmission system operator, a regional transmission organization, or a similar organization; comparable entities in Canada and Mexico; and the Electric Reliability Council of Texas or its successor. This sector also includes organizations that represent the interests of such entities.

xi. Regional entity — This sector includes any regional entity as defined in Article I, Section 1.

xii. Government representatives — This sector includes any federal, state, or provincial government department or agency in North America having a regulatory and/or policy interest in wholesale electricity. Entities with regulatory oversight over the Corporation or any regional entity, including U.S., Canadian, and Mexican federal agencies and any provincial entity in Canada having statutory oversight over the Corporation or a regional entity with respect to the approval and/or enforcement of reliability standards, may be nonvoting members of this sector.

b. A member may elect to be assigned to any sector so long as membership in that sector is consistent with the member's business or other activities. A corporation and its affiliates shall be considered a single member and may register in only one sector, which may be any single sector for which the corporation or any of its affiliates is eligible. A consultant, attorney, agent, vendor, trade or industry association, state, provincial or local consumer advocate organization that provides services to or

otherwise represents the interests of the members of one or more sectors may elect to be assigned to one such sector.

Section 5 — Term of Membership — Membership in the Corporation shall be retained as long as a member meets its respective qualifications, obligations, and conditions of membership as set forth in this Article II.

Section 6 — Removal — In addition to termination of membership in accordance with Article II, Section 2, the board, following notice to the member and exercise of appropriate due process procedures, may terminate the membership of a member if in the judgment of the board that member has violated its obligations and responsibilities to the Corporation. This termination shall require a two-thirds vote of the trustees present and voting at a meeting of the board at which a quorum of the board entitled to vote is present. Within thirty (30) days following the action of the board terminating the membership of a member, the member shall be entitled to appeal such termination to the Commission or to the applicable governmental authority in Canada or Mexico.

ARTICLE III
Board of Trustees

Section 1 — Board of Trustees — The business and affairs of the Corporation shall be managed by a Board of Trustees. The board shall consist of eleven members (the "trustees"), unless it is increased to twelve members pursuant to Section 1a of this Article III. All but one of the trustees shall be "independent" trustees nominated and elected in accordance with the requirements and procedures specified in Sections 2, 3, 4, 5, and 6 of this Article III (the "independent trustees"). The remaining trustee shall be the person elected by the board, in accordance with Article VI, Section 1, of these Bylaws, to serve as president of the Corporation (the "management trustee"). Each trustee, including the management trustee, shall have one (1) vote on any matter brought before the board for a vote. All trustees are expected to serve the public interest and to represent the reliability concerns of the entire North American bulk power system.

Section 1a — Increase in number of trustees — The board shall have the authority, by resolution, to increase the number of trustees from eleven to twelve, of which eleven trustees shall be independent trustees, with such increase to be effective as of the date of an annual election of independent trustees pursuant to Section 6 of this Article III. In order for the board to exercise this authority, the resolution increasing the number of trustees from eleven to twelve must be adopted by the board no later than December 1 immediately preceding the date of the annual election of independent trustees at which the increase is to be effective, and shall state a determination by the board that the increase is in the best interests of the Corporation and its Members. If the board adopts a resolution increasing the number of trustees from eleven to twelve, the nominating committee appointed pursuant to Section 5 of this Article III shall nominate a candidate to stand for election to the newly-created independent trustee position at the next annual election of independent trustees, along with candidates for the positions of independent trustees whose terms are expiring as of such election. The newly-created independent trustee position shall be filled by election in accordance with Section 6 of this Article III. Upon election of a trustee to the newly-created independent trustee position, the

board shall thereafter consist of twelve trustees, of whom eleven shall be independent trustees and one shall be the management trustee provided for in Section 1 of this Article III, unless the board decreases the number of trustees in accordance with Section 1b of this Article III.

Section 1b — Decrease in number of trustees — If the board has previously increased the number of trustees under Section 1a of this Section III, the board shall have the authority, by resolution, to decrease the number of trustees from twelve to eleven, of which ten trustees shall be independent trustees, with such decrease to be effective as of the date of an annual election of independent trustees pursuant to Section 6 of this Article III. The decrease in number of trustees shall be effected by eliminating one of the independent trustee positions whose term is expiring as of the date of such annual election of trustees, in which case no election shall be held to replace such trustee. In order for the board to exercise this authority, the resolution decreasing the number of trustees from twelve to eleven must be adopted by the board no later than September 1 immediately preceding the date of the annual election of independent trustees at which the decrease is to be effective; shall identify the independent trustee position expiring at the date of such annual election that shall be eliminated; and shall state a determination by the board that the decrease is in the best interests of the Corporation and its Members.

Section 2 — Composition of Board Based on Country Participation

a. The board shall consist of a number of trustees from the United States and from Canada. The number of trustees from Canada shall not be less than the percentage of the NEL of Canada to the total NEL of the United States and Canada, times eleven (or times twelve if the number of trustees has been increased to twelve pursuant to Section 1a of this Article III), rounded up to the nearest whole number. For purposes of this board composition requirement, the management trustee shall be counted as a trustee from Canada if he or she is a Canadian citizen.

b. When the Corporation receives recognition by appropriate regulatory authorities in Mexico as its electric reliability organization, the number of independent trustees will be increased by at least one, and the board composition requirement in subsection (a) will be expanded to include Mexico.

Section 3 — Independent Board Members — The independent trustees shall be elected, shall have the qualifications specified, and shall serve in the manner provided in this section.

a. An independent trustee is a person (i) who is not an officer or employee of the Corporation, 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.

b. Independent trustees shall be elected to terms expiring at the annual election of independent trustees occurring in the third year after their election. As of the original effective date of these Bylaws, the independent trustees of the Corporation and the date the term of each independent trustee expires were as follows:

Name	**Term Expires**
John Q. Anderson	2007
Paul F. Barber	2008
Thomas W. Berry	2007
Richard Drouin	2009
James M. Goodrich	2008
Donald P. Hodel	2008
Sharon L. Nelson	2007
Bruce A. Scherr	2009
Kenneth G. Peterson	2009
Fred Gorbet	2008

c. Independent trustees shall be nominated and elected pursuant to the nomination and election procedures specified in Sections 4, 5, and 6 of this Article III.

Section 4 — Vacancies on the Board —Should any vacancy on the board arise from the death, resignation, retirement, disqualification, or removal from office of any independent trustee, or from any other cause, such vacancy shall be filled by electing a trustee at the next annual election of trustees to fill the remainder, if any, of the term of the departed trustee. Provided, that the board by resolution may in its discretion call a special election to fill any such vacancy for the remainder, if any, of the term of the departed trustee. Any vacancy shall be filled so as to maintain the composition of the board in accordance with country participation pursuant to Section 2 of this Article III.

Section 5 — Nominating Committee — The board shall appoint, on an annual basis, or more frequently if needed in the event of a special election pursuant to Article III, Section 4, a nominating committee (the "nominating committee") to recommend candidates (i) to succeed the independent trustees whose terms expire during the current year and (ii) to serve the remainder of the term of any independent trustee who ceased to serve as a trustee subsequent to the last annual election of trustees. The nominating committee shall 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, provided, that the nominating committee shall be chaired by an independent trustee whose term does not expire during the current year and shall include at least three persons who are also members of the Member Representatives Committee, and provided further, that the nominating committee

formed for the purpose of recommending candidates to stand for election as trustees at the election to be held on or about February 1, 2007, pursuant to Article III, Section 6 shall not include any members of the Member Representatives Committee but shall include three

persons each of whom at the time of his or her appointment by the chair of the Stakeholders Committee of the North American Electric Reliability Council to the nominating committee shall be a member of that Stakeholders Committee. The board shall establish, by resolution, the procedures to be followed by the nominating committee in identifying and recommending candidates to serve as independent trustees; provided, however, that such procedures shall include a means of permitting members of the Corporation to recommend to the nominating committee candidates for consideration as nominees for independent trustees. The nominating committee shall nominate candidates for election to the board consistent with the requirements of Article III, Section 2 for board composition by country participation, and 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 operation issues; and reflects geographic diversity.

Section 6 — Election of Independent Trustees — The Member Representatives Committee of the Corporation shall elect the persons (i) to succeed those independent trustees whose terms expire each year and (ii) to serve the remainder of the term of any independent trustee who ceased to serve as a trustee subsequent to the last annual election of independent trustees. The annual election of independent trustees shall be scheduled to be conducted on or about February 1 of each year or as soon thereafter as is reasonably possible. Any special election pursuant to Article III, Section 2 shall be held as expeditiously as possible consistent with the time required for a nominating committee to be appointed and to nominate one or more candidates for the special election. All independent trustees shall be elected from nominees proposed by the nominating committee. A nominee shall be elected an independent trustee if such person receives the affirmative vote of two-thirds of the members of the Member Representatives Committee. Each nominee receiving the necessary two-thirds vote of the Member Representatives Committee shall take office immediately upon election. In the event that the voting fails to elect a nominee to fill any of the positions of independent trustee to be filled in an annual election of independent trustees, the nominating committee shall as promptly as reasonably possible consider and propose one or more additional nominee or nominees for that position, and a vote by the Member Representatives Committee on the election of such nominee or nominees shall be conducted as quickly as possible. For avoidance of doubt, the independent trustees shall be elected by the Member Representatives Committee in accordance with this Section 6 and shall not be elected by vote of the members of the Corporation.

Section 7 — Management Trustee — The president of the Corporation shall be, ex officio, the management trustee of the Corporation, effective as of the date of his or her election by the board as president of the Corporation in accordance with Article VI, Section 1, of these Bylaws, to serve until such time that he or she ceases to hold the position of president.

Section 8 — Committees of the Board — The board shall by resolution create and appoint all committees of the board as the board deems necessary to perform its responsibilities;

provided, that the management trustee shall not be a member of the audit committee or of the human resources committee, if any. All committees of the board shall have such duties as are prescribed by the board. Notice to the public of the dates, places, and times of meetings of

board committees, and all nonconfidential material provided to committee members, shall be posted on the Corporation's Web site within 24 hours of the time that notice is given to committee members. Meetings of board committees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity.

ARTICLE IV
Meetings of Members of the Corporation

Section 1 — Meetings of Members — Meetings of members of the Corporation may be called for any purpose or purposes by the chairman of the board or by a number of members constituting at least ten (10) percent of the members on the roster of members maintained by the secretary of the Corporation, which number shall include members in at least three of the sectors. Meetings of members shall be held at the principal office of the Corporation or at such other place fixed by the board as shall be specified in the notice of meeting. Meetings shall be called upon written notice of the time, date, place, and purposes of the meeting given to all members on the roster of members maintained by the secretary of the Corporation not less than ten (10) nor more than sixty days (60) prior to the date of the meeting.

Section 2 — Quorum and Voting Requirements for Meetings of Members — At any meeting of the members of the Corporation, attendance in person or by proxy by one-half of the members in each of at least two-thirds of the sectors on the roster of members maintained by the secretary of the Corporation shall constitute a quorum. Except as otherwise expressly provided in the Corporation's Certificate of Incorporation, these Bylaws or applicable law, actions by the members of the Corporation shall be approved upon receipt of seven affirmative votes at a meeting of the members of the Corporation at which a quorum is present, where (i) each sector of the Corporation shall have one vote, except that if less than one-half of the members in a sector are present, in person or by proxy, at the meeting, the vote of that sector shall be weighted by a percentage equal to the number of members of the sector present in person or by proxy at the meeting divided by one-half of the members in the sector; (ii) the vote of each sector of the Corporation shall be allocated for and against the proposed action based on the respective percentages of votes cast for and against the proposed action by the members in that sector voting in person or by proxy; and (iii) the proportions of the votes of each sector allocated for and against the proposed action shall be summed to determine the total number of votes for and against the proposed action.

Section 3 — Waivers of Notice of Meetings of Members; and Member Meeting Adjournments — Notice of a meeting of members need not be given to any member who signs a waiver of notice, in person or by proxy, whether before or after the meeting. The attendance of any member at a meeting, in person or by proxy, without protesting prior to the conclusion of the meeting the lack of notice of such meeting, shall constitute a waiver of notice of the meeting by such member. When any meeting of members is adjourned to

another time or place, it shall not be necessary to give notice of the adjourned meeting if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken, and if at the adjourned meeting only such business is transacted as might have been transacted at the original meeting.

Section 4 — Action Without a Meeting of Members — Any action, required or permitted to be taken at a meeting of members, may be taken without a meeting if the action is consented to in writing by the minimum number of members that would be required to approve the action at a meeting of the members at which all members were present. The call for action without a meeting of members may be initiated by the chairman of the board or by a number of members constituting at least ten (10) percent of the members on the roster of members maintained by the secretary of the Corporation, which number shall include members in at least three of the sectors. Notice of the proposal for action without a meeting shall be provided to all members on the roster of members maintained by the secretary of the Corporation at least ten (10) days prior to the date established for the tabulation of consents.
The members shall receive written notice of the results, and the results shall be posted on the Corporation's Web site, within ten (10) days of the action vote, and all written responses of the members shall be filed with the minutes of proceedings of members.

Section 5 — Meetings of the Members to be Open — Notice to the public of the dates, places, and times of meetings of the members, and all nonconfidential material provided to the members, shall be posted on the Corporation's Web site within 24 hours of the time that notice is given to the members. Meetings of the members shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity.

ARTICLE V
Meetings of the Board of Trustees

Section 1 — Regular Meetings of the Board — A regular meeting of the board for such business as may come before the meeting shall be held on or about February 1 of each year. By resolution adopted at any meeting of the board, the board may provide for additional regular meetings that may be held without further notice to the trustees.

Section 2 — Special Meetings of the Board — Special meetings of the board for any purpose or purposes may be called at any time by the chairman or by any two trustees. Such meetings may be held upon notice given to all trustees not less than five (5) days prior to the date of the meeting unless the meeting is a closed session as permitted by Article V, Section 4 of these Bylaws, in which event the notice shall be provided to all trustees not less than 24 hours prior to the date and time of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, telegraph, or other electronic media, or by express delivery.

Section 3 — Quorum and Voting Requirements for Meetings of the Board — Unless otherwise expressly provided in the Corporation's Certificate of Incorporation, these Bylaws or applicable law, (i) the quorum necessary for the transaction of business at meetings of the board shall be a majority of the trustees, and (ii) actions by the board shall be approved upon receipt of the affirmative vote of a majority of the trustees present and voting at a meeting at which a quorum is present.

Section 4 — Meetings of the Board to be Open — Notice to the public of the dates, places, and times of meetings of the board, and all nonconfidential material provided to the board, shall be posted on the Corporation's Web site, and notice of meetings of the board shall be sent electronically to members of the Corporation, within 24 hours of the time that notice or such material is given to the trustees. Meetings of the board shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the board may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity. Any or all of the trustees, or members of a committee, may participate in a meeting of the board, or a meeting of a committee, by means of a communications system by which all persons participating in the meeting are able to hear each other.

Section 5 — Waivers of Notice of Board Meetings; and Board Meeting Adjournments — Notice of a board meeting need not be given to any trustee who signs a waiver of notice, in person or by proxy, whether before or after the meeting, or who attends the meeting without protesting, prior to the conclusion of the meeting, the lack of notice of such meeting. Notice of an adjourned board meeting need not be given if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if the period of adjournment does not exceed ten (10) days.

Section 6 — Action Without a Meeting — Any action, required or permitted to be taken at a meeting of the board or of any committee thereof, may be taken by the board or by the committee without a meeting if the action is consented to in writing by the number of trustees or members of the committee, as the case may be, entitled to vote on the action that would be required to approve the action at a meeting of the board or committee with all members of the board or committee present. The call for action without a meeting of the board may be initiated by the chairman or by any two trustees. Notice of the proposed call for action without a meeting, and all nonconfidential material provided to the board in connection with the call for action without a meeting, shall be posted on the Corporation's Web site within 24 hours of the time notice of the call for action without a meeting or such material is provided to the board. The call for action without a meeting of a committee of the board may be initiated by the chairman or by any two members of the committee. The trustees or members of the committee shall receive written notice of the results, and unless the action was confidential the results shall be posted on the Corporation's Web site, within seven (7) days of the action vote. All written responses of the trustees shall be filed with the minutes of the Corporation, and all written responses of members of a committee shall be filed with the minutes of such committee.

ARTICLE VI
Officers

Section 1 — Officers — At its regular meeting held on or about February 1 of each year in accordance with Section 1 of Article V of these Bylaws, the board shall elect a chairman, a vice chairman, a president, a secretary, a treasurer, an assistant secretary-treasurer, and such other officers of the Corporation (collectively, the "officers") as it shall deem necessary. The chairman and the vice chairman must each be independent trustees prior to their election to such offices. The chairman, vice chairman, and president shall each be nominated and elected by the board. All of the remaining officers shall be appointed or removed by the board based upon the recommendation of the president. The duties and authority of the chairman, the vice chairman, and the president shall be determined from time to time by the board, and the duties and authority of the other officers of the Corporation shall be determined from time to time by the president. Subject to any such determination, the officers shall have the following duties and authority:

a. The chairman shall preside at all meetings of the members and at all meetings of the board. The chairman, in consultation with the other trustees, shall be responsible for the efficient operation of the board and its committees. The chairman shall be an ex officio member of each committee of the board. The chairman may delegate from time to time any or all of the aforesaid duties and authority to the vice chairman, another trustee, the president, or any other officer.

b. The vice chairman shall have such duties and possess such other powers as may be delegated to him or her by the chairman. The vice chairman shall act as the chairman at such times as the chairman may request. In the event the chairman is unable to discharge the duties and powers of that office by reason of incapacity and during any vacancies in the office of the chairman, the vice chairman shall act as chairman until the cessation of such incapacity or the filling of such vacancy.

c. The president shall be the chief executive officer of the Corporation. He or she shall be responsible for the day-to-day ongoing activities of the Corporation and shall have such other duties as may be delegated or assigned to him or her by the chairman. The president may enter into and execute in the name of the Corporation contracts or other instruments not in the regular course of business that are authorized, either generally or specifically, by the board.

d. The secretary shall maintain the roster of members of the Corporation; shall cause notices of all meetings to be served as prescribed in these Bylaws; shall keep or cause to be kept the minutes of all meetings of the members and the board; and shall have charge of the seal of the Corporation. The secretary shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the president.

e. The treasurer shall have custody of the funds and securities of the Corporation, and shall keep or cause to be kept regular books of account for the Corporation. The treasurer shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the president.

f. The assistant secretary-treasurer shall have such duties and possess such other powers as may be delegated to him or her by the president.

ARTICLE VII
Committees of the Corporation

Section 1 — Committees of the Corporation — In addition to those committees specified by these Bylaws, to which the board shall appoint members in accordance with the requirements of these Bylaws, the board may by resolution create standing committees of the Corporation; and may in addition by resolution appoint such other committees as the board deems necessary to carry out the purposes of the Corporation. The board shall appoint standing committees and other committees of the Corporation that are representative of members, other interested parties and the public, that provide for balanced decision making, and that include persons with outstanding technical knowledge and experience. All appointments of committees of the Corporation shall provide the opportunity for an equitable number of members from the United States and Canada (and from Mexico after the Corporation receives recognition by appropriate governmental authorities in Mexico as its electric reliability organization) to be appointed to each committee in approximate proportion to each country's percentage of the total NEL. All committees shall have such scope and duties, not inconsistent with law, as are specified in these Bylaws and the Rules of Procedure of the Corporation or otherwise determined by the board.

ARTICLE VIII
Member Representatives Committee

Section 1 — Member Representatives Committee — The Corporation shall have a Member Representatives Committee that shall have the following rights and obligations:

a. to elect the independent trustees, in accordance with Article III, Section 6;

b. to vote on amendments to the Bylaws, in accordance with Article XIV~~XVI~~; and

c. to provide advice and recommendations to the board with respect to the development of annual budgets, business plans and funding mechanisms, and other matters pertinent to the purpose and operations of the Corporation.

Because it is elected by the members of the Corporation and not appointed by the board, the Member Representatives Committee shall not be a standing committee of the Corporation, but is authorized to provide its advice and recommendations directly to the board.

Section 2 — Composition of the Member Representatives Committee — The Member Representatives Committee shall consist of (i) two representatives from each sector except the government representative sector and the regional entity sector, (ii) two voting representatives from the regional entity sector, with the remaining members of that sector being non-voting members of the Member Representatives Committee, (iii) the chairman and vice chairman of the Member Representatives Committee, (iv) any additional Canadian representatives as are selected pursuant to Section 4 of this Article VIII, and (v) 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 Member Representatives Committee except the two representatives of state governments. The representatives of each sector shall be members of the Corporation, or officers or executive-level employees, agents or representatives of members of the Corporation, in that sector; provided, that at any time only one officer, employee, agent, or representative of a member in a sector may be a representative from that sector. No member of the board shall be a member of the Member Representatives Committee. The board may by resolution create additional nonvoting positions on the Member Representatives Committee at the written request of any group of members of the Corporation that believes its interests are not adequately represented on the Member Representatives Committee.

In order to provide that the terms of approximately one-half of the members of the Member Representatives Committee expire each year, on the initial Member Representatives Committee one-half of the representatives from each sector shall serve a term expiring at the next annual meeting, and one-half of the representatives from each sector shall serve a term expiring at the second succeeding annual meeting, in each case held pursuant to Section 7 of this Article VIII.

Following the expiration of the terms of the members of the initial Member Representatives Committee as provided above, each member of the Member Representatives Committee shall thereafter serve a term of two years commencing at an annual meeting held pursuant to Section 7 of this Article VIII and ending at the second succeeding annual meeting. There shall be no limit on the number of terms that a member of the Corporation, or an employee, agent, or representative of a member of the Corporation, may serve on the Member Representatives Committee.

Section 3 — Election of Members of the Member Representatives Committee

a. Unless a sector adopts an alternative election procedure, the annual election of representatives from each sector to the Member Representatives Committee, and any election to fill a vacancy, shall be conducted in accordance with the following process, which shall be administered by the officers of the Corporation. During the period beginning approximately ninety (90) days and ending approximately thirty (30) days prior to an annual election, or beginning approximately forty-five (45) days and ending approximately fifteen (15) days prior to an election to fill a vacancy, nominations may be submitted for candidates for election to the Member Representatives Committee, provided that for the initial election the period may

begin as soon as these bylaws are made effective and may end approximately fifteen (15) days prior to the election. A nominee for election as a sector representative must be a member, or an officer, executive-level employee or agent of a member, in that sector. No more than one nominee who is an officer, executive-level employee or agent of a member or its affiliates may stand for election in any single sector; if more than one officer, employee or agent of a member or its affiliates is nominated for election from a sector, the member shall designate which such nominee shall stand for election. The election of representatives shall be conducted over a period of ten (10) days using an electronic process. Each member in a sector shall have one vote for each representative to be elected from the sector in that election, and may cast no more than one vote for any nominee. The nominee receiving the highest number of votes in each sector shall be elected to the representative position to be filled from that sector; if there is more than one representative position to be filled from a sector, the nominee receiving the second highest number of votes shall also be elected, and so forth. Provided, that to be elected a nominee must receive a number of votes equal to a simple majority of the members in the sector casting votes in the election. If no nominee in a sector receives a simple majority of votes cast in the first ballot, a second ballot shall be conducted which shall be limited to the number of candidates receiving the two (2) highest vote totals on the first ballot (or to the number of candidates receiving the four (4) highest vote totals on the first ballot if two representative positions remain to be filled, and so forth). The nominee or nominees receiving the highest total or totals of votes on the second ballot shall be elected to the representative position or positions remaining to be filled for the sector.

A sector may adopt an alternative procedure to the foregoing to nominate and elect its representatives to the Member Representatives Committee if (i) the alternative procedure is consistent in principle with the procedures specified in the preceding paragraph of this Section 3a, and (ii) the alternative procedure is approved by vote of at least two-thirds of the members in the sector. Any alternative procedure is subject to review and disapproval by the board.

Section 4 — Adequate Representation of Canadian Interests on the Member Representatives Committee — In addition to the requirements for composition of the Member Representatives Committee specified in Section 1 of this Article VIII, the Member Representatives Committee shall contain a number of Canadian voting representatives equal to the percentage of the NEL of Canada to the total NEL of the United States and Canada, times the total number of voting members on the Member Representatives Committee, rounded up to the next whole number. If the annual selection of members of the Member Representatives Committee pursuant to Section 3 of this Article VIII does not result in the number of Canadian voting representatives provided for herein on the Member Representatives Committee, then the candidate who received the highest fraction of the sector vote among those candidates who would have qualified as Canadian voting representatives but were not elected to the Member Representatives Committee shall be added to the Member Representatives Committee. Additional Canadian voting representatives shall be added to the

Member Representatives Committee through this selection process until the Member Representatives Committee includes a number of Canadian voting representatives equal to the percentage of the NEL of Canada to the total NEL of the United States and Canada, times the total number of voting members on the Member Representatives Committee, rounded up to the next whole number. Provided, that no more than one such additional Canadian voting representative shall be selected from a sector, except that if this limitation precludes the addition of the number of additional Canadian voting representatives required by the previous sentence, then no more than two Canadian voting representatives may be selected from the same sector. Such additional Canadian voting representatives shall be representatives of the sectors in which they stood for election, and shall serve terms expiring at the next annual meeting of the Member Representatives Committee pursuant to Section 7 of this Article VIII. For purposes of this Section 4, "Canadian" means one of the following: (a) a company or association incorporated or organized under the laws of Canada or of a province of Canada that is a member of the Corporation, or its designated representative irrespective of nationality; (b) an agency of a federal, provincial, or local government in Canada that is a member of the Corporation, or its designated representative irrespective of nationality; or (c) a person who is a Canadian citizen residing in Canada and is a member of the Corporation.

When the Corporation receives recognition from appropriate governmental authorities in Mexico as the electric reliability organization, this provision will be expanded to provide for adequate representation of Mexican interests on the Member Representatives Committee.

Section 5 — Officers of the Member Representatives Committee — At the initial meeting of the Member Representatives Committee, and annually thereafter prior to the annual election of representatives to the Member Representatives Committee, the Member Representatives Committee shall select a chairman and vice chairman from among its voting members by majority vote of the members of the Member Representatives Committee to serve as chairman and vice chairman of the Member Representatives Committee during the upcoming year; provided, that the incumbent chairman and vice chairman shall not vote or otherwise participate in the selection of the incoming chairman and vice-chairman. The newly selected chairman and vice chairman shall not have been representatives of the same sector. Selection of the chairman and vice chairman shall not be subject to approval of the board. The chairman and vice chairman, upon assuming such positions, shall cease to act as representatives of the sectors that elected them as representatives to the Member Representatives Committee and shall thereafter be responsible for acting in the best interests of the members as a whole.

Section 6 — Vacancies on the Member Representatives Committee — In the event that any member of the Member Representatives Committee ceases to serve as a member of the Member Representatives Committee as a result of his or her death, resignation, retirement, disqualification, or removal or other cause, the members in the sector of which such member was a representative shall elect, as soon thereafter as reasonably possible, and in accordance with the procedures in Sections 3 and 4 of this Article VIII, a new member to replace the member of the Member Representatives Committee who ceases to serve. Except with regard to the selection of the chairman and vice chairman at the initial meeting of the Member Representatives Committee, the vacancies in the sector representatives created by the

selection of the chair and vice chair pursuant to Section 5 of this Article VIII shall be filled at the annual election of representatives to the Member Representatives Committee that is next held following the election of the chairman and vice chairman. In the case of the selection of the chairman and vice chairman at the initial meeting of the Member Representatives Committee, the sector representative vacancies created thereby shall be filled as soon thereafter as reasonably possible in accordance with the procedures in Section 3 of this Article VIII for sector representative vacancies.

Section 7 — Annual Meeting of the Member Representatives Committee — An annual meeting of the Member Representatives Committee for the election of independent trustees and to conduct such other business as may come before the meeting shall be held on or about February 1 of each year or as soon thereafter as is reasonably possible. By resolution adopted at any meeting of the Member Representatives Committee, the Member Representatives Committee may provide for additional regular meetings that may be held without further notice to the members of the Member Representatives Committee.

Section 8 — Special Meetings of the Member Representatives Committee — Special meetings of the Member Representatives Committee for any purpose or purposes may be called by the chair of the Member Representatives Committee or by any five (5) members of the Member Representatives Committee, which number shall include representatives from at least three sectors, and require notice given to all members of the Member Representatives Committee not less than seven (7) days prior to the date of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, telegraph, or other electronic media, or by express delivery.

Section 9 — Quorums and Voting for Meetings of the Member Representatives Committee — The quorum necessary for the transaction of business at meetings of the Member Representatives Committee shall be two-thirds of the voting members of the Member Representatives Committee attending the meeting in person or by proxy. A member of the Member Representatives Committee may give a proxy only to a person who is a member, or an officer, executive-level employee, agent or representative of a member, registered in the same sector. Each voting member of the Member Representatives Committee shall have one (1) vote on any matter coming before the Member Representatives Committee that requires a vote. Except as otherwise expressly provided in the Corporation's Certificate of Incorporation, these Bylaws or applicable law, actions by members of the Member Representatives Committee shall be approved upon receipt of the affirmative vote of a majority of the voting members of the Member Representatives Committee present and voting, in person or by proxy, at any meeting at which a quorum is present.

Section 10 — Meetings of the Member Representatives Committee to be Open — Notice to the public of the dates, places, and times of meetings of the Member Representatives Committee, and all nonconfidential material provided to the Member Representatives Committee, shall be posted on the Corporation's Web site, and notice of meetings of the Member Representatives Committee shall be sent electronically to all members of the Corporation, within 24 hours of the time that notice or such material is given to the Member Representatives Committee. Meetings of the Member Representatives Committee shall be open to the public, subject to reasonable limitations due to the availability and size of meeting

facilities; provided, that the Member Representatives Committee may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity. Any or all members of, and any other participants in, the Member Representatives Committee may participate in a meeting of the Member Representatives Committee by a means of a communications system by which all persons participating in the meeting are able to hear each other.

Section 11 — Waivers of Notice of Meetings of the Member Representatives Committee; and Meeting Adjournments — Notice of a meeting of the Member Representatives Committee need not be given to any member of the Member Representatives Committee who signs a waiver of notice, in person or by proxy, whether before or after the meeting, or who attends the meeting without protesting, prior to the conclusion of the meeting, the lack of notice of such meeting. Notice of an adjourned meeting of the Member Representatives Committee need not be given if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if the period of adjournment does not exceed ten (10) days.

Section 12 — Action Without a Meeting of the Member Representatives Committee — Any action required or permitted to be taken at a meeting of the Member Representatives Committee may be taken by the Member Representatives Committee without a meeting if the action is consented to in writing by the number of members of the Member Representatives Committee entitled to vote on the action that would be required to approve the action at a meeting of the Member Representatives Committee with all of its members present. The call for action without a meeting of the Member Representatives Committee may be initiated by the Chair of the Member Representatives Committee or by any five (5) members of the Member Representatives Committee, which number shall include representatives from at least three (3) sectors. Notice of the proposed call for action without a meeting, and all nonconfidential material provided to the Member Representatives Committee in connection with the call for action without a meeting, shall be posted on the Corporation's Web site within 24 hours of the time notice of the call for action without a meeting or such material is provided to the members of the Members Representative Committee. The members of the Member Representatives Committee shall receive written notice of the results, and the results shall be posted on the Corporation's Web site, within seven (7) days of the action vote, and all written responses of voting members of the Member Representatives Committee shall be filed with the minutes of the Corporation.

Section 13 — Other Procedures of the Member Representatives Committee — The chairman of the board in office on November 1, 2006, shall preside at the initial meeting of the Member Representatives Committee, until a chairman is selected in accordance with Section 5 of this Article VIII. Except as to any matter as to which the procedure to be followed by the Member Representatives Committee is expressly set forth in these Bylaws, the Member Representatives Committee may adopt such additional procedures, not inconsistent with these Bylaws, as it deems appropriate.

ARTICLE IX
Reliability Standards

Section 1 — Development of Reliability Standards — The Corporation shall develop, implement and, in all regions in which necessary governmental approvals have been obtained or authority has been provided, enforce, reliability standards that provide for reliable operation of the bulk power systems of North America. All reliability standards shall be approved by the board. All reliability standards of the Corporation shall be posted on its Web site. Nothing in this Article shall be deemed to invalidate any standard of the Corporation that was in effect on November 1, 2006.

Section 2 — Procedures for Development of Reliability Standards —The Corporation shall develop reliability standards pursuant to procedures and processes that shall be specified in the Rules of Procedure of the Corporation. The Rules of Procedure shall provide for the development of reliability standards through an open, transparent, and public process that provides for reasonable notice and opportunity for public comment, due process, and balancing of interests and is designed to result in reliability standards that are technically sound. Participation in the process for development of 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 bulk power system.

Section 3 — Procedures for Determinations of Violations of Reliability Standards and Imposition of Sanctions for Violations — In all regions in which regulatory approval has been obtained or governmental authority has been provided, the Corporation shall consider and make determinations that an owner, operator, or user of the bulk power system has violated a reliability standard, and shall impose sanctions for such violations, pursuant to procedures and processes that shall be specified in the Rules of Procedure of the Corporation. Such procedures and processes shall provide for reasonable notice and opportunity for hearing. Any sanction imposed for a violation of a reliability standard shall bear a reasonable relation to the seriousness of the violation and shall take into consideration efforts of the owner, operator, or user of the bulk power system to remedy the violation in a timely manner. Subject to any necessary action by any applicable governmental authorities, no sanction imposed for a violation of a reliability standard shall take effect until the thirty-first (31) day after the Corporation, where authorized by law or agreement, files with the Commission or other applicable governmental authority notice of the sanction and the record of the proceedings in which the violation and sanction were determined, or such other date as ordered by the Commission or other applicable governmental authority or as prescribed by applicable law.

ARTICLE X
Agreements with Regional Entities

Section 1 — Delegation Agreements with Regional Entities — The Corporation may, in accordance with appropriate governmental authority, enter into agreements with regional entities pursuant to which a regional entity shall be delegated the authority of the Corporation to enforce reliability standards within a geographic region of North America and may

develop and propose reliability standards to be in effect within such region. All delegation agreements with regional entities shall be approved by the board. No delegation agreement with a regional entity shall be effective with respect to a region until the agreement has received any necessary approval from an applicable governmental authority.

Section 2 — Standards for Delegation Agreements — The Corporation shall be permitted to enter into a delegation agreement with a regional entity only if the board determines that (i) the regional entity has agreed to promote, support, and comply with the purposes and policies of the Corporation as set forth in its Certificate of Incorporation, Bylaws, Rules of Procedure, and Reliability Standards as from time to time adopted, approved, or amended; (ii) the regional entity satisfies the criteria set forth in Sections 39.3(b) and 39.8 of the Commission's regulations, or other criteria specified by applicable governmental authorities, and (iii) the delegation agreement will promote effective and efficient administration of the reliability of the bulk power system.

ARTICLE XI
Rules of Procedure

Section 1 — Development of Rules of Procedure — The Corporation shall develop and implement such Rules of Procedure as in the judgment of the board are necessary or appropriate to carry out the purposes of the Corporation and to govern its operations, including without limiting the foregoing, Rules of Procedure relating to (i) registration of owners, operators, and users of the bulk power system; (ii) development of reliability standards; (iii) procedures for standing committees of the Corporation, subgroups of standing committees, and other committees, subcommittees, task forces, and sector-specific forums of the Corporation; (iv) critical infrastructure protection; (v) conduct of readiness evaluations and reliability assessments; (vi) enforcement of compliance with reliability standards and determinations of violations of reliability standards by owners, operators, and users of the bulk power system; (vii) impositions of sanctions for violations of reliability standards; (viii) development, implementation, and administration of delegation agreements with regional entities; (ix) personnel certification; (x) event analysis and information exchange; (xi) realtime monitoring of the bulk power system; and (xii) development and administration of budgets, business plans, and funding mechanisms of the Corporation. All Rules of Procedure of the Corporation shall be posted on its Web site.

Section 2 — Adoption, Amendment, and Repeal of Rules of Procedure — Except as provided in Section 2 of Article XII, all Rules of Procedure, amendments thereto and repeals thereof shall be approved by the board. Proposals to adopt new Rules of Procedure or to amend or repeal existing Rules of Procedure may be submitted by (i) the Member Representatives Committee, (ii) any fifty (50) members of the Corporation, which number shall include members in at least three sectors, (iii) a committee of the Corporation to whose purpose and functions the Rule of Procedure pertains, or (iv) an officer of the Corporation. Unless the board determines that exigent conditions exist requiring adoption of a new Rule of Procedure or amendment or repeal of an existing Rule of Procedure in a shorter time, all proposals for adoption, amendment and repeal of Rules of Procedure shall be posted on the Corporation's Web site and subject to public comment for a minimum of forty-five (45) days

prior to action by the board. All Rules of Procedure and amendments to and repeals of Rules of Procedure approved by the board shall be submitted to the Commission and to other applicable governmental authorities for approval, and shall not be effective in the United States until approved by the Commission or in Canada or Mexico until approval is obtained from any governmental authority from which approval is required in those countries and subject to any conditions, limitations, or modifications required by the Commission or other governmental authority. Nothing in this Article shall be deemed to invalidate any Rule of Procedure of the Corporation that was in effect on November 1, 2006.

ARTICLE XII
Personnel Certification Governance Committee

Section 1 — Personnel Certification Governance Committee — There shall be a Personnel Certification Governance Committee of the Corporation, which shall be a standing committee of the Corporation. The purpose of the Personnel Certification Governance Committee shall be to provide oversight to the policies and processes used to implement and maintain the integrity and independence of the Corporation's System Operator Certification Program. The governance authority and structure of the Personnel Certification Governance Committee shall be implemented and maintained so that policies and procedures are established to protect against undue influence that could compromise the integrity of the System Operator Certification process.

Section 2 — Appointment and Reporting of the Personnel Certification Governance Committee — The members of the Personnel Certification Governance Committee shall be appointed by the board from candidates selected and presented by a nominating task force in accordance with Rules of Procedure for the Personnel Certification Governance Committee. Nominations and appointments shall take into account the need to include representatives of all geographic regions of North America on the Personnel Certification Governance Committee. The Personnel Certification Governance Committee shall report directly to the board and the president of the Corporation regarding governance and administration of the System Operator Certification Program; provided, however, that the Personnel Certification Governance Committee shall have autonomy in developing and implementing system operator certification eligibility requirements, the development, administration, and scoring of the system operator assessment instruments, and operational processes for the System Operator Certification Program. The Personnel Certification Governance Committee shall provide to the board periodic assessments, no less frequently than every two (2) years, of the effectiveness of the System Operator Certification Program.

Section 3 — Administration of the Personnel Certification Governance Committee — In order to maintain the independence of the Personnel Certification Governance Committee, staff of the Corporation shall administer the System Operator Certification program on behalf of the Personnel Certification Governance Committee on a fee for service basis.

ARTICLE XIII
Budgets and Funding

Section 1 — Compensation of the Board and Member Representatives Committee — The board shall have the right to fix from time to time, by resolution adopted by a majority of the independent trustees then serving as trustees, the amount of the annual retainer fee or other compensation to be paid to the independent trustees for their services to the Corporation, including any fees to be paid for each meeting of the board or any board committee attended by an independent trustee. No compensation shall be paid to the management trustee for his or her services on the board, other than the compensation paid to the management trustee for services as president of the Corporation. No compensation shall be paid by the Corporation to the members of the Member Representatives Committee for their services on the Member Representatives Committee.

Section 2 — Preparation and Adoption of Annual Budget, Business Plan, and Funding Mechanism — The board shall prepare or cause to be prepared an annual budget for the administrative and other expenses of the Corporation, including the expenditures for the fiscal year for any material special projects undertaken by the Corporation and reasonable and proper reserves and provisions for contingencies, an accompanying business plan for the Corporation, and a funding mechanism, for each fiscal year. The annual budget, business plan, and funding mechanism of the Corporation shall be for a fiscal year commencing on January 1 and ending on December 31. Each annual budget, business plan, and funding mechanism (including the annual budget, annual business plan, and annual funding mechanism for each regional entity) shall be approved by the board at a regular meeting or a special meeting of the board duly called for that purpose. The board shall approve each annual budget, business plan, and funding mechanism at least 135 days before the start of the fiscal year in order to allow for timely submittal of the approved annual budget, business plan, and funding mechanism to the applicable governmental authorities.

Section 3 — Criteria for Funding Mechanisms — The annual funding mechanism shall be designed to recover, over the course of the fiscal year, the sum of (i) the annual budget, (ii) less revenues projected to be received by the Corporation from other sources such as sales of services and materials and registration, application and certification fees for programs conducted or administered by the Corporation, and (iii) plus or minus the estimated deficiency or excess of the Corporation's revenues compared to its expenditures for the current fiscal year. The annual funding mechanism shall consist of such assessments as determined by the 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.

Section 4 — Consultation in Preparation of Annual Budget, Business Plan, and Funding Mechanism — In preparing the annual budget, business plan, and funding mechanism, the board shall consult with the members of the Member Representatives Committee, and shall post a draft budget and business plan for review and comment by the members of the Corporation and the Member Representatives Committee and the standing committees of the Corporation for at least thirty (30) days prior to the date of the meeting of the board at which the annual budget, business plan, and funding mechanism are to be adopted.

Section 5 — Modified or Supplemental Funding Mechanisms — During the course of a fiscal year, the board may modify the approved funding mechanism or develop and approve a supplemental funding mechanism if determined by the board to be necessary due to such factors as a shortfall in revenues of the Corporation from projected levels, incurred or anticipated expenditures or new projects not provided for in the annual budget, or such other factors as in the judgment of the board warrant modification of the funding mechanism for the fiscal year or development of a supplemental funding mechanism. In preparing a modified or supplemental funding mechanism, the board shall follow the provisions of Section 4 of this

Article XIII to the extent possible in the judgment of the board in light of the exigency of the circumstances necessitating preparation and approval of the modified or supplemental funding mechanism. Each modified or supplemental funding mechanism shall be approved by the board at a regular meeting or a special meeting of the board duly called for that purpose.

Section 6 — Submission of Annual Budgets, Business Plans, and Funding Mechanisms to the Governmental Authorities — Each annual budget, annual business plan, and annual, modified, or supplemental funding mechanism approved by the board (including the annual budget, annual business plan, and annual, modified, or supplemental funding mechanism for each regional entity) shall be submitted by the Corporation to the applicable governmental authorities for approval in accordance with its regulations, except as otherwise provided by applicable law or by agreement, and shall not be effective until it has received any necessary approval by the applicable governmental authorities. If a governmental authority by order modifies or remands an annual budget, business plan, or annual, modified, or supplemental funding mechanism, the board shall promptly following such order adopt such modifications to the budget, business plan, or funding mechanism as are required or directed by the order of the governmental authority.

ARTICLE XIV
Amendments to the Bylaws

Section 1 — Amendments to the Bylaws — These Bylaws may be altered, amended, or repealed by a majority vote of both the board and the Member Representatives Committee at respective meetings of the board and the Members Representative Committee at which a quorum is present. Written notice of the subject matter of the proposed changes to the Bylaws shall be provided, as appropriate, to the trustees or to the Member Representatives Committee not less than ten (10) nor more than sixty (60) days prior to the date of the meeting of the board or of the Member Representatives Committee at which the vote is to be taken. Notwithstanding the provisions of this Article XIV, the members of the Corporation voting by sector shall have the right to alter, amend, or repeal Bylaws adopted by the board and the Member Representatives Committee and to adopt new Bylaws, provided that any such alteration, amendment, or repeal or the adoption of new Bylaws is approved by vote of two-thirds of the sectors at a meeting of Members called for that purpose, or by written consent of two-thirds of the sectors, where the number of votes for and against the proposed alteration, amendment, repeal, or adoption of Bylaws shall be determined in accordance with Section 2 of Article IV. Any alteration, amendment, repeal, or adoption of Bylaws shall be subject to

any applicable requirements for filing with or approval by the Commission and any other applicable governmental authority.

ARTICLE XV
General

Section 1 — Indemnification — The Corporation shall indemnify its officers, trustees and other corporate agents to the full extent from time to time permitted by the New Jersey Nonprofit Corporation Act and other applicable law. Such right of indemnification shall inure to the benefit of the legal representative of any such person. The foregoing indemnification shall be in addition to, and not in restriction or limitation of, any privilege or power that the Corporation may have with respect to the indemnification or reimbursement of its trustees, officers, or other corporate agents. The Corporation shall also pay or advance expenses incurred by an officer, trustee, or other corporate agent in connection with a proceeding in advance of the final disposition of the proceeding upon receipt of an undertaking by or on behalf of the officer, trustee, or other corporate agent to repay the amount unless it shall be ultimately determined that the officer, trustee, or other corporate agent is entitled to be indemnified by the Corporation.

Section 2 — Parliamentary Rules — In the absence of and to the extent not inconsistent with specific provisions in these Bylaws, meetings or other actions pursuant to these Bylaws shall be governed by procedures that the board may, from time to time, establish by resolution.

Section 3 — Dissolution — Upon dissolution of the Corporation, in accordance with paragraph TENTH of the Certificate of Incorporation, the remaining assets of the Corporation after payment of debts shall be distributed in the manner determined by the board, provided, (i) that no part of the assets shall be distributed to any trustee of the Corporation, and (ii) that the distribution of assets shall be consistent with the requirements of Section 501(c)(6) of the United States Internal Revenue Code of 1986, as amended.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

June 4, 2018

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Petition for Approval of Amendments to the Bylaws of the North American Electric Reliability Corporation
Docket No. RR18-_-000

Dear Secretary Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits a "*Petition for Approval of Amendments to the Bylaws of the North American Electric Reliability Corporation*." As described in greater detail in the Petition, NERC proposes to amend the Bylaws by reducing the required timeframe for notice of special closed sessions of the Board of Trustees. In addition, NERC also proposes to correct a minor typographical error in Article VIII, Section 1(b) of the Bylaws.

This filing consists of: (1) this transmittal letter; (2) the narrative text of the filing; and (3) **Attachments 1** and **2** which contain clean and redline versions of the proposed amendments to NERC Bylaws, respectively. All documents are transmitted in a single PDF file.

Please contact the undersigned if you have any questions concerning this filing.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston
Senior Counsel
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nina.johnston@nerc.net

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR18-_-000**

PETITION
FOR APPROVAL OF AMENDMENTS TO THE BYLAWS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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June 4, 2018

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR18-_-000**

PETITION FOR APPROVAL OF AMENDMENTS TO THE BYLAWS OF THE NORTH AMERICAN RELIABILITY CORPORATION

Pursuant to § 215(f) of the Federal Power Act ("FPA")[1] and 18 C.F.R. § 39.10[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC") hereby requests Commission approval of proposed amendments to the NERC Bylaws. The NERC Bylaws are "Electric Reliability Organization Rules" as defined in 18 C.F.R. § 39.10, and, in accordance with 18 C.F.R. § 39.10, require Commission approval.[3]

NERC proposes to amend Article V, Section 1 of the Bylaws to reduce the 5 day prior notice requirement for Board of Trustee ("Board") meetings. This amendment will allow for a 24 hour prior notice for special board meetings that are held in closed session. However, the revision 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 Board of Trustees. Specifically, the shortened notice period will permit the Board to address matters that may be considered during a closed session in a more timely manner when necessary, while not changing the notice provided to stakeholders of any Board meeting.

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1 16 U.S.C. § 824o (2006).
2 18 C.F.R. § 39.5 (2018).
3 18 C.F.R. § 39.10 (2018).

Below are the texts of the proposed amendments to Section 2 of Article V and Section 1 of Article VIII of the Bylaws. **Attachments 1** and **2** to this filing contain the complete NERC Bylaws with the proposed amendments, in clean and redlined format, respectively.

ARTICLE V

Meetings of the Board of Trustees

Section 2 - Special Meetings of the Board - Special meetings of the board for any purpose or purposes may be called at any time by the chairman or by any two trustees. Such meetings may be held upon notice given to all trustees not less than five (5) days prior to the date of the meeting unless the meeting is a closed session as permitted by Article V, Section 4 of these Bylaws, in which event the notice shall be provided to all trustees not less than 24 hours prior to the date and time of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, telegraph or other electronic media, or by express delivery.

ARTICLE VIII

Member Representatives Committee

Section 1 - Member Representatives Committee - The Corporation shall have a Member Representatives Committee that shall have the following rights and obligations:

a. to elect the independent trustees, in accordance with Article III, Section 6;
b. to vote on amendments to the Bylaws, in accordance with Article ~~XVI~~XIV; and
c. to provide advice and recommendations to the board with respect to the development of annual budgets, business plans and funding mechanisms, and other matters pertinent to the purpose and operations of the Corporation.

Because it is elected by the members of the Corporation and not appointed by the board, the Member Representatives Committee shall not be a standing committee of the Corporation, but is authorized to provide its advice and recommendations directly to the board.

I. APPROVAL PROCESS FOR THE BYLAW AMENDMENTS

Article XIV, Section 1 of the NERC Bylaws sets forth the required procedure for approval of amendments to the Bylaws:

> **Section 1 – Amendments to the Bylaws –** These Bylaws may be altered, amended, or repealed by a majority vote of both the board and the Member Representatives Committee at respective meetings of the board and the Members Representative Committee at which a quorum is present. Written notice of the subject matter of the proposed changes to the Bylaws shall be provided, as appropriate, to the trustees or to the Member Representatives Committee not less than ten (10) nor more than sixty (60) days prior to the date of the meeting of the board or of the Member Representatives Committee at which the vote is to be taken. Notwithstanding the provisions of this Article XIV, the members of the Corporation voting by sector shall have the right to alter, amend, or repeal Bylaws adopted by the board and the Member Representatives Committee and to adopt new Bylaws, provided that any such alteration, amendment, or repeal or the adoption of new Bylaws is approved by vote of two-thirds of the sectors at a meeting of Members called for that purpose, or by written consent of two-thirds of the sectors, where the number of votes for and against the proposed alteration, amendment, repeal, or adoption of Bylaws shall be determined in accordance with Section 2 of Article IV. Any alteration, amendment, repeal, or adoption of Bylaws shall be subject to any applicable requirements for filing with or approval by the Commission and any other applicable governmental authority.

The requirements of Article XIV, Section 1 were followed in obtaining approval of the proposed amended Bylaws that are the subject of this filing. At the January 24, 2018 Corporate Governance and Human Resources Committee meeting, NERC management recommended adoption of these revisions to the NERC Bylaws. On February 8, 2018, the NERC Board of Trustees, upon the recommendation of the Corporate Governance and Human Resources Committee, approved the proposed revisions to the NERC Bylaws. The proposed amended Bylaws were approved by the MRC at its meeting held on May 9, 2018. The applicable notice was provided to the Board of Trustees and the MRC, respectively, upon the public posting of their agenda packages. The required quorums of the Board and the MRC were present at their respective meetings.

II. CONCLUSION

NERC respectfully requests that the Commission approve the proposed amendments to the NERC Bylaws, as shown in **Attachments 1** and **2** to this Petition.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston

Nina H. Jenkins-Johnston
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Counsel for the North American Electric Reliability Corporation

Dated: June 4, 2018

ATTACHMENT 1

Amended North American Electric Reliability Corporation Bylaws – **Clean**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Bylaws

Approved by the Board of Trustees: February 8, 2018
Effective: [Proposed Date]

BYLAWS

OF THE

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ARTICLE I
Definitions

Section 1 — Definitions — As used in these Bylaws of the North American Electric Reliability Corporation (hereinafter referred to as "the Corporation"), the terms set forth in this Article I shall have the meanings set forth herein.

"Applicable governmental authority" means the Federal Energy Regulatory Commission within the United States and the appropriate governmental authority with subject matter jurisdiction over reliability within Canada and Mexico.

"Board" means the Board of Trustees of the Corporation.

"Bulk power system" means facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and 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.

"Commission" means the Federal Energy Regulatory Commission.

"Electric reliability organization" or "ERO" means the organization that is certified by the Commission under Section 39.3 of its regulations, the purpose of which is to establish and enforce Reliability Standards for the bulk power system in the United States. The organization may also have received recognition by applicable governmental authorities in Canada and Mexico to establish and enforce reliability standards for the bulk power systems of the respective countries.

"Member" means a member of the Corporation pursuant to Article II of these Bylaws.

"Net Energy for Load (NEL)" means 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 storage of energy at energy storage facilities. Calculations of net energy for load for all purposes under these Bylaws shall be based on the most recent calendar year for which data on net energy for load of applicable regions of the United States, Canada, and Mexico is available.

"Regional entity" means an entity having enforcement authority pursuant to 18 C.F.R. § 39.8.

"Reliability standard" means a requirement to provide for reliable operation of the bulk power system, including without limiting the foregoing requirements for the operation of existing bulk power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary for reliable operation of the bulk power system, but shall not include any requirement to enlarge bulk power system facilities or to construct new transmission capacity or generation capacity.

"Reliable operation" means operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of the bulk power system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

"Sector" means a group of members of the Corporation that are bulk power system owners, operators, or users or other persons and entities with substantially similar interests, including governmental entities, as pertinent to the purposes and operations of the Corporation and the operation of the bulk power system, as defined in Article II, Section 4 of these Bylaws. Each sector shall constitute a class of members for purposes of the New Jersey Nonprofit Corporation Act.

Section 2 — Additional Defined Terms — Additional terms not defined in this Article I are defined in the remainder of these Bylaws.

Section 3 — Technical Terms — Technical terms not defined in these Bylaws shall have the definitions set forth in the Federal Power Act, Part 39 of the regulations of the Commission, or the "Glossary of Terms Used in Reliability Standards", in that order of precedence, and if not defined in any of those sources, shall be defined in accordance with their commonly understood and used technical meaning in the electric power industry, including applicable codes and standards.

ARTICLE II
Membership

Section 1 — Members — Membership in the Corporation is voluntary and is open to any person or entity that has an interest in the reliable operation of the North American bulk power system and that registers with the Corporation as a member, maintains its registration in accordance with this Article II, and complies with the other conditions and obligations of membership specified in these Bylaws. Membership in a regional entity shall not be a condition for membership in the Corporation. The secretary of the Corporation shall maintain a roster of the members of the Corporation.

Section 2 — Registration as a Member — Any person or entity that is eligible to be a member of the Corporation in accordance with Article II, Section 1 may become a member by completing, and submitting to the secretary of the Corporation, a membership registration on a form prescribed by the board. If not a natural person, the member shall designate a

representative and an alternative representative with authority to receive notices, cast votes, and execute waivers and consents on behalf of the member. The secretary of the Corporation shall maintain a current roster of the members of the Corporation including each member's designated representative and alternative representative. From time to time, the board shall establish a date by which members shall submit their registration renewals. All members shall be required to renew their registrations within 30 calendar days of a request by the secretary of the Corporation, using a registration renewal form prescribed by the board. The secretary of the Corporation shall remove from the roster of members of the Corporation any member that has not submitted a registration renewal within 30 days following a date established by the board. The secretary shall notify any member that is removed from the roster of members of such removal, by notice sent to such former member's last known address on the records of the Corporation.

Section 3 — Obligations and Conditions of Membership

a. Each member shall agree, in writing, to accept the responsibility to promote, support, and comply with the purposes and policies of the Corporation as set forth in its Certificate of Incorporation, Bylaws, Rules of Procedure, and Reliability Standards as from time to time adopted, approved, or amended.

b. As an additional condition of membership in the Corporation, each person or entity registering as a member shall be required to execute an agreement with the Corporation, in a form to be specified by the board, that such person or entity will hold all trustees, officers, employees, and agents of the Corporation, as well as volunteers participating in good faith in the activities of the Corporation, harmless, to the extent permitted by Federal or provincial laws, regulations and rules, for any injury or damage to that member caused by any act or omission of any trustee, officer, employee, agent, or volunteer in the course of performance of his or her duties on behalf of the Corporation, other than for acts of gross negligence, intentional misconduct, or a breach of confidentiality.

Section 4 — Membership Sectors

a. Each member shall elect to be assigned to one of the following membership sectors: (i) investor-owned utility; (ii) state/municipal utility; (iii) cooperative utility; (iv) federal or provincial utility/power marketing administration; (v) transmission-dependent utility; (vi) merchant electricity generator; (vii) electricity marketer; (viii) large end-use electricity customer; (ix) small end-use electricity customer; (x) independent system operator/regional transmission organization; (xi) regional entity; or (xii) government representatives. The composition of each sector shall be as follows:

    i. Investor-owned utility — This sector includes any investor-owned entity with a substantial business interest in ownership and/or operation in any of the asset categories of generation, transmission or distribution. This sector also includes organizations that represent the interests of such entities.

ii. State/municipal utility — This sector includes any entity owned by or subject to the governmental authority of a state or municipality, that is engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the state or municipality; and any entity, whose members are municipalities, formed under state law for the purpose of generating, transmitting, or purchasing electricity for sale at wholesale to their members. This sector also includes organizations that represent the interests of such entities.

iii. Cooperative utility — This sector includes any non-governmental entity that is incorporated under the laws of the state in which it operates, is owned by and provides electric service to end-use customers at cost, and is governed by a board of directors that is elected by the membership of the entity; and any non-governmental entity owned by and which provides generation and/or transmission service to such entities. This sector also includes organizations that represent the interests of such entities.

iv. Federal or provincial utility/Federal Power Marketing Administration — This sector includes any U.S. federal, Canadian provincial, or Mexican entity that owns and/or operates electric facilities in any of the asset categories of generation, transmission, or distribution; or that functions as a power marketer or power marketing administrator. This sector also includes organizations that represent the interests of such entities.

v. Transmission-dependent utility — This sector includes any entity with a regulatory, contractual, or other legal obligation to serve wholesale aggregators or customers or end-use customers and that depends primarily on the transmission systems of third parties to provide this service. This sector also includes organizations that represent the interests of such entities.

vi. Merchant electricity generator — This sector includes any entity that owns or operates an electricity generating facility that is not included in an investor-owned utility's rate base and that does not otherwise fall within any of sectors (i) through (v). This sector includes but is not limited to cogenerators, small power producers, and all other nonutility electricity producers such as exempt wholesale generators who sell electricity at wholesale. This sector also includes organizations that represent the interests of such entities.

vii. Electricity marketer — This sector includes any entity that is engaged in the activity of buying and selling of wholesale electric power in North America on a physical or financial basis. This sector also includes organizations that represent the interests of such entities.

viii. Large end-use electricity customer — This sector includes any entity in North America with at least one service delivery taken at 50 kV or higher (radial supply or facilities dedicated to serve customers) that is not purchased for resale; and any single end-use customer with an average aggregated service load (not purchased for resale) of at least 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations that represent the interests of such entities.

ix. Small end-use electricity customer — This sector includes any person or entity within North America that takes service below 50 kV; and any single end-use customer with an average aggregated service load (not purchased for resale) of less than 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations (including state consumer advocates) that represent the interests of such entities.

x. Independent system operator/regional transmission organization — This sector includes any entity authorized by the Commission to function as an independent transmission system operator, a regional transmission organization, or a similar organization; comparable entities in Canada and Mexico; and the Electric Reliability Council of Texas or its successor. This sector also includes organizations that represent the interests of such entities.

xi. Regional entity — This sector includes any regional entity as defined in Article I, Section 1.

xii. Government representatives — This sector includes any federal, state, or provincial government department or agency in North America having a regulatory and/or policy interest in wholesale electricity. Entities with regulatory oversight over the Corporation or any regional entity, including U.S., Canadian, and Mexican federal agencies and any provincial entity in Canada having statutory oversight over the Corporation or a regional entity with respect to the approval and/or enforcement of reliability standards, may be nonvoting members of this sector.

b. A member may elect to be assigned to any sector so long as membership in that sector is consistent with the member's business or other activities. A corporation and its affiliates shall be considered a single member and may register in only one sector, which may be any single sector for which the corporation or any of its affiliates is eligible. A consultant, attorney, agent, vendor, trade or industry association, state, provincial or local consumer advocate organization that provides services to or otherwise represents the interests of the members of one or more sectors may elect to be assigned to one such sector.

Section 5 — Term of Membership — Membership in the Corporation shall be retained as long as a member meets its respective qualifications, obligations, and conditions of membership as set forth in this Article II.

Section 6 — Removal — In addition to termination of membership in accordance with Article II, Section 2, the board, following notice to the member and exercise of appropriate due process procedures, may terminate the membership of a member if in the judgment of the board that member has violated its obligations and responsibilities to the Corporation. This termination shall require a two-thirds vote of the trustees present and voting at a meeting of the board at which a quorum of the board entitled to vote is present. Within thirty (30) days following the action of the board terminating the membership of a member, the member shall be entitled to appeal such termination to the Commission or to the applicable governmental authority in Canada or Mexico.

ARTICLE III
Board of Trustees

Section 1 — Board of Trustees — The business and affairs of the Corporation shall be managed by a Board of Trustees. The board shall consist of eleven members (the "trustees"), unless it is increased to twelve members pursuant to Section 1a of this Article III. All but one of the trustees shall be "independent" trustees nominated and elected in accordance with the requirements and procedures specified in Sections 2, 3, 4, 5, and 6 of this Article III (the "independent trustees"). The remaining trustee shall be the person elected by the board, in accordance with Article VI, Section 1, of these Bylaws, to serve as president of the Corporation (the "management trustee"). Each trustee, including the management trustee, shall have one (1) vote on any matter brought before the board for a vote. All trustees are expected to serve the public interest and to represent the reliability concerns of the entire North American bulk power system.

Section 1a — Increase in number of trustees — The board shall have the authority, by resolution, to increase the number of trustees from eleven to twelve, of which eleven trustees shall be independent trustees, with such increase to be effective as of the date of an annual election of independent trustees pursuant to Section 6 of this Article III. In order for the board to exercise this authority, the resolution increasing the number of trustees from eleven to twelve must be adopted by the board no later than December 1 immediately preceding the date of the annual election of independent trustees at which the increase is to be effective, and shall state a determination by the board that the increase is in the best interests of the Corporation and its Members. If the board adopts a resolution increasing the number of trustees from eleven to twelve, the nominating committee appointed pursuant to Section 5 of this Article III shall nominate a candidate to stand for election to the newly-created independent trustee position at the next annual election of independent trustees, along with candidates for the positions of independent trustees whose terms are expiring as of such election. The newly-created independent trustee position shall be filled by election in accordance with Section 6 of this Article III. Upon election of a trustee to the newly-created independent trustee position, the board shall thereafter consist of twelve trustees, of whom eleven shall be independent trustees and one shall be the management trustee provided for in Section 1 of this Article III, unless the

board decreases the number of trustees in accordance with Section 1b of this Article III.

Section 1b — Decrease in number of trustees — If the board has previously increased the number of trustees under Section 1a of this Section III, the board shall have the authority, by resolution, to decrease the number of trustees from twelve to eleven, of which ten trustees shall be independent trustees, with such decrease to be effective as of the date of an annual election of independent trustees pursuant to Section 6 of this Article III. The decrease in number of trustees shall be effected by eliminating one of the independent trustee positions whose term is expiring as of the date of such annual election of trustees, in which case no election shall be held to replace such trustee. In order for the board to exercise this authority, the resolution decreasing the number of trustees from twelve to eleven must be adopted by the board no later than September 1 immediately preceding the date of the annual election of independent trustees at which the decrease is to be effective; shall identify the independent trustee position expiring at the date of such annual election that shall be eliminated; and shall state a determination by the board that the decrease is in the best interests of the Corporation and its Members.

Section 2 — Composition of Board Based on Country Participation

a. The board shall consist of a number of trustees from the United States and from Canada. The number of trustees from Canada shall not be less than the percentage of the NEL of Canada to the total NEL of the United States and Canada, times eleven (or times twelve if the number of trustees has been increased to twelve pursuant to Section 1a of this Article III), rounded up to the nearest whole number. For purposes of this board composition requirement, the management trustee shall be counted as a trustee from Canada if he or she is a Canadian citizen.

b. When the Corporation receives recognition by appropriate regulatory authorities in Mexico as its electric reliability organization, the number of independent trustees will be increased by at least one, and the board composition requirement in subsection (a) will be expanded to include Mexico.

Section 3 — Independent Board Members — The independent trustees shall be elected, shall have the qualifications specified, and shall serve in the manner provided in this section.

a. An independent trustee is a person (i) who is not an officer or employee of the Corporation, 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.

b. Independent trustees shall be elected to terms expiring at the annual election of independent trustees occurring in the third year after their election. As of the original effective date of these Bylaws, the independent trustees of the Corporation and the date the term of each independent trustee expires were as follows:

Name	**Term Expires**
John Q. Anderson	2007
Paul F. Barber	2008
Thomas W. Berry	2007
Richard Drouin	2009
James M. Goodrich	2008
Donald P. Hodel	2008
Sharon L. Nelson	2007
Bruce A. Scherr	2009
Kenneth G. Peterson	2009
Fred Gorbet	2008

c. Independent trustees shall be nominated and elected pursuant to the nomination and election procedures specified in Sections 4, 5, and 6 of this Article III.

Section 4 — Vacancies on the Board —Should any vacancy on the board arise from the death, resignation, retirement, disqualification, or removal from office of any independent trustee, or from any other cause, such vacancy shall be filled by electing a trustee at the next annual election of trustees to fill the remainder, if any, of the term of the departed trustee. Provided, that the board by resolution may in its discretion call a special election to fill any such vacancy for the remainder, if any, of the term of the departed trustee. Any vacancy shall be filled so as to maintain the composition of the board in accordance with country participation pursuant to Section 2 of this Article III.

Section 5 — Nominating Committee — The board shall appoint, on an annual basis, or more frequently if needed in the event of a special election pursuant to Article III, Section 4, a nominating committee (the "nominating committee") to recommend candidates (i) to succeed the independent trustees whose terms expire during the current year and (ii) to serve the remainder of the term of any independent trustee who ceased to serve as a trustee subsequent to the last annual election of trustees. The nominating committee shall 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, provided, that the nominating committee shall be chaired by an independent trustee whose term does not expire during the current year and shall include at least three persons who are also members of the Member Representatives Committee, and provided further, that the nominating committee formed for the purpose of recommending candidates to stand for election as trustees at the election to be held on or about February 1, 2007, pursuant to Article III, Section 6 shall not include any members of the Member Representatives Committee but shall include three

persons each of whom at the time of his or her appointment by the chair of the Stakeholders Committee of the North American Electric Reliability Council to the nominating committee shall be a member of that Stakeholders Committee. The board shall establish, by resolution, the procedures to be followed by the nominating committee in identifying and recommending candidates to serve as independent trustees; provided, however, that such procedures shall include a means of permitting members of the Corporation to recommend to the nominating committee candidates for consideration as nominees for independent trustees. The nominating committee shall nominate candidates for election to the board consistent with the requirements of Article III, Section 2 for board composition by country participation, and 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 operation issues; and reflects geographic diversity.

Section 6 — Election of Independent Trustees — The Member Representatives Committee of the Corporation shall elect the persons (i) to succeed those independent trustees whose terms expire each year and (ii) to serve the remainder of the term of any independent trustee who ceased to serve as a trustee subsequent to the last annual election of independent trustees. The annual election of independent trustees shall be scheduled to be conducted on or about February 1 of each year or as soon thereafter as is reasonably possible. Any special election pursuant to Article III, Section 2 shall be held as expeditiously as possible consistent with the time required for a nominating committee to be appointed and to nominate one or more candidates for the special election. All independent trustees shall be elected from nominees proposed by the nominating committee. A nominee shall be elected an independent trustee if such person receives the affirmative vote of two-thirds of the members of the Member Representatives Committee. Each nominee receiving the necessary two-thirds vote of the Member Representatives Committee shall take office immediately upon election. In the event that the voting fails to elect a nominee to fill any of the positions of independent trustee to be filled in an annual election of independent trustees, the nominating committee shall as promptly as reasonably possible consider and propose one or more additional nominee or nominees for that position, and a vote by the Member Representatives Committee on the election of such nominee or nominees shall be conducted as quickly as possible. For avoidance of doubt, the independent trustees shall be elected by the Member Representatives Committee in accordance with this Section 6 and shall not be elected by vote of the members of the Corporation.

Section 7 — Management Trustee — The president of the Corporation shall be, ex officio, the management trustee of the Corporation, effective as of the date of his or her election by the board as president of the Corporation in accordance with Article VI, Section 1, of these Bylaws, to serve until such time that he or she ceases to hold the position of president.

Section 8 — Committees of the Board — The board shall by resolution create and appoint all committees of the board as the board deems necessary to perform its responsibilities; provided, that the management trustee shall not be a member of the audit committee or of the human resources committee, if any. All committees of the board shall have such duties as are prescribed by the board. Notice to the public of the dates, places, and times of meetings of

board committees, and all nonconfidential material provided to committee members, shall be posted on the Corporation's Web site within 24 hours of the time that notice is given to committee members. Meetings of board committees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity.

ARTICLE IV
Meetings of Members of the Corporation

Section 1 — Meetings of Members — Meetings of members of the Corporation may be called for any purpose or purposes by the chairman of the board or by a number of members constituting at least ten (10) percent of the members on the roster of members maintained by the secretary of the Corporation, which number shall include members in at least three of the sectors. Meetings of members shall be held at the principal office of the Corporation or at such other place fixed by the board as shall be specified in the notice of meeting. Meetings shall be called upon written notice of the time, date, place, and purposes of the meeting given to all members on the roster of members maintained by the secretary of the Corporation not less than ten (10) nor more than sixty days (60) prior to the date of the meeting.

Section 2 — Quorum and Voting Requirements for Meetings of Members — At any meeting of the members of the Corporation, attendance in person or by proxy by one-half of the members in each of at least two-thirds of the sectors on the roster of members maintained by the secretary of the Corporation shall constitute a quorum. Except as otherwise expressly provided in the Corporation's Certificate of Incorporation, these Bylaws or applicable law, actions by the members of the Corporation shall be approved upon receipt of seven affirmative votes at a meeting of the members of the Corporation at which a quorum is present, where (i) each sector of the Corporation shall have one vote, except that if less than one-half of the members in a sector are present, in person or by proxy, at the meeting, the vote of that sector shall be weighted by a percentage equal to the number of members of the sector present in person or by proxy at the meeting divided by one-half of the members in the sector; (ii) the vote of each sector of the Corporation shall be allocated for and against the proposed action based on the respective percentages of votes cast for and against the proposed action by the members in that sector voting in person or by proxy; and (iii) the proportions of the votes of each sector allocated for and against the proposed action shall be summed to determine the total number of votes for and against the proposed action.

Section 3 — Waivers of Notice of Meetings of Members; and Member Meeting Adjournments — Notice of a meeting of members need not be given to any member who signs a waiver of notice, in person or by proxy, whether before or after the meeting. The attendance of any member at a meeting, in person or by proxy, without protesting prior to the conclusion of the meeting the lack of notice of such meeting, shall constitute a waiver of notice of the meeting by such member. When any meeting of members is adjourned to another time or place, it shall not be necessary to give notice of the adjourned meeting if the time and place to which the meeting is adjourned are announced at the meeting at which the

adjournment is taken, and if at the adjourned meeting only such business is transacted as might have been transacted at the original meeting.

Section 4 — Action Without a Meeting of Members — Any action, required or permitted to be taken at a meeting of members, may be taken without a meeting if the action is consented to in writing by the minimum number of members that would be required to approve the action at a meeting of the members at which all members were present. The call for action without a meeting of members may be initiated by the chairman of the board or by a number of members constituting at least ten (10) percent of the members on the roster of members maintained by the secretary of the Corporation, which number shall include members in at least three of the sectors. Notice of the proposal for action without a meeting shall be provided to all members on the roster of members maintained by the secretary of the Corporation at least ten (10) days prior to the date established for the tabulation of consents.
The members shall receive written notice of the results, and the results shall be posted on the Corporation's Web site, within ten (10) days of the action vote, and all written responses of the members shall be filed with the minutes of proceedings of members.

Section 5 — Meetings of the Members to be Open — Notice to the public of the dates, places, and times of meetings of the members, and all nonconfidential material provided to the members, shall be posted on the Corporation's Web site within 24 hours of the time that notice is given to the members. Meetings of the members shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity.

ARTICLE V
Meetings of the Board of Trustees

Section 1 — Regular Meetings of the Board — A regular meeting of the board for such business as may come before the meeting shall be held on or about February 1 of each year. By resolution adopted at any meeting of the board, the board may provide for additional regular meetings that may be held without further notice to the trustees.

Section 2 — Special Meetings of the Board — Special meetings of the board for any purpose or purposes may be called at any time by the chairman or by any two trustees. Such meetings may be held upon notice given to all trustees not less than five (5) days prior to the date of the meeting unless the meeting is a closed session as permitted by Article V, Section 4 of these Bylaws, in which event the notice shall be provided to all trustees not less than 24 hours prior to the date and time of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, telegraph, or other electronic media, or by express delivery.

Section 3 — Quorum and Voting Requirements for Meetings of the Board — Unless otherwise expressly provided in the Corporation's Certificate of Incorporation, these Bylaws or applicable law, (i) the quorum necessary for the transaction of business at meetings of the board shall be a majority of the trustees, and (ii) actions by the board shall be approved upon

receipt of the affirmative vote of a majority of the trustees present and voting at a meeting at which a quorum is present.

Section 4 — Meetings of the Board to be Open — Notice to the public of the dates, places, and times of meetings of the board, and all nonconfidential material provided to the board, shall be posted on the Corporation's Web site, and notice of meetings of the board shall be sent electronically to members of the Corporation, within 24 hours of the time that notice or such material is given to the trustees. Meetings of the board shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the board may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity. Any or all of the trustees, or members of a committee, may participate in a meeting of the board, or a meeting of a committee, by means of a communications system by which all persons participating in the meeting are able to hear each other.

Section 5 — Waivers of Notice of Board Meetings; and Board Meeting Adjournments — Notice of a board meeting need not be given to any trustee who signs a waiver of notice, in person or by proxy, whether before or after the meeting, or who attends the meeting without protesting, prior to the conclusion of the meeting, the lack of notice of such meeting. Notice of an adjourned board meeting need not be given if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if the period of adjournment does not exceed ten (10) days.

Section 6 — Action Without a Meeting — Any action, required or permitted to be taken at a meeting of the board or of any committee thereof, may be taken by the board or by the committee without a meeting if the action is consented to in writing by the number of trustees or members of the committee, as the case may be, entitled to vote on the action that would be required to approve the action at a meeting of the board or committee with all members of the board or committee present. The call for action without a meeting of the board may be initiated by the chairman or by any two trustees. Notice of the proposed call for action without a meeting, and all nonconfidential material provided to the board in connection with the call for action without a meeting, shall be posted on the Corporation's Web site within 24 hours of the time notice of the call for action without a meeting or such material is provided to the board. The call for action without a meeting of a committee of the board may be initiated by the chairman or by any two members of the committee. The trustees or members of the committee shall receive written notice of the results, and unless the action was confidential the results shall be posted on the Corporation's Web site, within seven (7) days of the action vote. All written responses of the trustees shall be filed with the minutes of the Corporation, and all written responses of members of a committee shall be filed with the minutes of such committee.

ARTICLE VI
Officers

Section 1 — Officers — At its regular meeting held on or about February 1 of each year in

accordance with Section 1 of Article V of these Bylaws, the board shall elect a chairman, a vice chairman, a president, a secretary, a treasurer, an assistant secretary-treasurer, and such other officers of the Corporation (collectively, the "officers") as it shall deem necessary. The chairman and the vice chairman must each be independent trustees prior to their election to such offices. The chairman, vice chairman, and president shall each be nominated and elected by the board. All of the remaining officers shall be appointed or removed by the board based upon the recommendation of the president. The duties and authority of the chairman, the vice chairman, and the president shall be determined from time to time by the board, and the duties and authority of the other officers of the Corporation shall be determined from time to time by the president. Subject to any such determination, the officers shall have the following duties and authority:

a. The chairman shall preside at all meetings of the members and at all meetings of the board. The chairman, in consultation with the other trustees, shall be responsible for the efficient operation of the board and its committees. The chairman shall be an ex officio member of each committee of the board. The chairman may delegate from time to time any or all of the aforesaid duties and authority to the vice chairman, another trustee, the president, or any other officer.

b. The vice chairman shall have such duties and possess such other powers as may be delegated to him or her by the chairman. The vice chairman shall act as the chairman at such times as the chairman may request. In the event the chairman is unable to discharge the duties and powers of that office by reason of incapacity and during any vacancies in the office of the chairman, the vice chairman shall act as chairman until the cessation of such incapacity or the filling of such vacancy.

c. The president shall be the chief executive officer of the Corporation. He or she shall be responsible for the day-to-day ongoing activities of the Corporation and shall have such other duties as may be delegated or assigned to him or her by the chairman. The president may enter into and execute in the name of the Corporation contracts or other instruments not in the regular course of business that are authorized, either generally or specifically, by the board.

d. The secretary shall maintain the roster of members of the Corporation; shall cause notices of all meetings to be served as prescribed in these Bylaws; shall keep or cause to be kept the minutes of all meetings of the members and the board; and shall have charge of the seal of the Corporation. The secretary shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the president.

e. The treasurer shall have custody of the funds and securities of the Corporation, and shall keep or cause to be kept regular books of account for the Corporation. The treasurer shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the president.

f. The assistant secretary-treasurer shall have such duties and possess such other powers as may be delegated to him or her by the president.

ARTICLE VII
Committees of the Corporation

Section 1 — Committees of the Corporation — In addition to those committees specified by these Bylaws, to which the board shall appoint members in accordance with the requirements of these Bylaws, the board may by resolution create standing committees of the Corporation; and may in addition by resolution appoint such other committees as the board deems necessary to carry out the purposes of the Corporation. The board shall appoint standing committees and other committees of the Corporation that are representative of members, other interested parties and the public, that provide for balanced decision making, and that include persons with outstanding technical knowledge and experience. All appointments of committees of the Corporation shall provide the opportunity for an equitable number of members from the United States and Canada (and from Mexico after the Corporation receives recognition by appropriate governmental authorities in Mexico as its electric reliability organization) to be appointed to each committee in approximate proportion to each country's percentage of the total NEL. All committees shall have such scope and duties, not inconsistent with law, as are specified in these Bylaws and the Rules of Procedure of the Corporation or otherwise determined by the board.

ARTICLE VIII
Member Representatives Committee

Section 1 — Member Representatives Committee — The Corporation shall have a Member Representatives Committee that shall have the following rights and obligations:

a. to elect the independent trustees, in accordance with Article III, Section 6;

b. to vote on amendments to the Bylaws, in accordance with Article XIV; and

c. to provide advice and recommendations to the board with respect to the development of annual budgets, business plans and funding mechanisms, and other matters pertinent to the purpose and operations of the Corporation.

Because it is elected by the members of the Corporation and not appointed by the board, the Member Representatives Committee shall not be a standing committee of the Corporation, but is authorized to provide its advice and recommendations directly to the board.

Section 2 — Composition of the Member Representatives Committee — The Member Representatives Committee shall consist of (i) two representatives from each sector except the government representative sector and the regional entity sector, (ii) two voting representatives from the regional entity sector, with the remaining members of that sector being non-voting

members of the Member Representatives Committee, (iii) the chairman and vice chairman of the Member Representatives Committee, (iv) any additional Canadian representatives as are selected pursuant to Section 4 of this Article VIII, and (v) 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 Member Representatives Committee except the two representatives of state governments. The representatives of each sector shall be members of the Corporation, or officers or executive-level employees, agents or representatives of members of the Corporation, in that sector; provided, that at any time only one officer, employee, agent, or representative of a member in a sector may be a representative from that sector. No member of the board shall be a member of the Member Representatives Committee. The board may by resolution create additional nonvoting positions on the Member Representatives Committee at the written request of any group of members of the Corporation that believes its interests are not adequately represented on the Member Representatives Committee.

In order to provide that the terms of approximately one-half of the members of the Member Representatives Committee expire each year, on the initial Member Representatives Committee one-half of the representatives from each sector shall serve a term expiring at the next annual meeting, and one-half of the representatives from each sector shall serve a term expiring at the second succeeding annual meeting, in each case held pursuant to Section 7 of this Article VIII.

Following the expiration of the terms of the members of the initial Member Representatives Committee as provided above, each member of the Member Representatives Committee shall thereafter serve a term of two years commencing at an annual meeting held pursuant to Section 7 of this Article VIII and ending at the second succeeding annual meeting. There shall be no limit on the number of terms that a member of the Corporation, or an employee, agent, or representative of a member of the Corporation, may serve on the Member Representatives Committee.

Section 3 — Election of Members of the Member Representatives Committee

a. Unless a sector adopts an alternative election procedure, the annual election of representatives from each sector to the Member Representatives Committee, and any election to fill a vacancy, shall be conducted in accordance with the following process, which shall be administered by the officers of the Corporation. During the period beginning approximately ninety (90) days and ending approximately thirty (30) days prior to an annual election, or beginning approximately forty-five (45) days and ending approximately fifteen (15) days prior to an election to fill a vacancy, nominations may be submitted for candidates for election to the Member Representatives Committee, provided that for the initial election the period may begin as soon as these bylaws are made effective and may end approximately fifteen (15) days prior to the election. A nominee for election as a sector representative must be a member, or an officer, executive-level employee or agent of a member, in that sector. No more than one nominee who is an officer, executive-level employee

or agent of a member or its affiliates may stand for election in any single sector; if more than one officer, employee or agent of a member or its affiliates is nominated for election from a sector, the member shall designate which such nominee shall stand for election. The election of representatives shall be conducted over a period of ten (10) days using an electronic process. Each member in a sector shall have one vote for each representative to be elected from the sector in that election, and may cast no more than one vote for any nominee. The nominee receiving the highest number of votes in each sector shall be elected to the representative position to be filled from that sector; if there is more than one representative position to be filled from a sector, the nominee receiving the second highest number of votes shall also be elected, and so forth. Provided, that to be elected a nominee must receive a number of votes equal to a simple majority of the members in the sector casting votes in the election. If no nominee in a sector receives a simple majority of votes cast in the first ballot, a second ballot shall be conducted which shall be limited to the number of candidates receiving the two (2) highest vote totals on the first ballot (or to the number of candidates receiving the four (4) highest vote totals on the first ballot if two representative positions remain to be filled, and so forth). The nominee or nominees receiving the highest total or totals of votes on the second ballot shall be elected to the representative position or positions remaining to be filled for the sector.

A sector may adopt an alternative procedure to the foregoing to nominate and elect its representatives to the Member Representatives Committee if (i) the alternative procedure is consistent in principle with the procedures specified in the preceding paragraph of this Section 3a, and (ii) the alternative procedure is approved by vote of at least two-thirds of the members in the sector. Any alternative procedure is subject to review and disapproval by the board.

Section 4 — Adequate Representation of Canadian Interests on the Member Representatives Committee — In addition to the requirements for composition of the Member Representatives Committee specified in Section 1 of this Article VIII, the Member Representatives Committee shall contain a number of Canadian voting representatives equal to the percentage of the NEL of Canada to the total NEL of the United States and Canada, times the total number of voting members on the Member Representatives Committee, rounded up to the next whole number. If the annual selection of members of the Member Representatives Committee pursuant to Section 3 of this Article VIII does not result in the number of Canadian voting representatives provided for herein on the Member Representatives Committee, then the candidate who received the highest fraction of the sector vote among those candidates who would have qualified as Canadian voting representatives but were not elected to the Member Representatives Committee shall be added to the Member Representatives Committee. Additional Canadian voting representatives shall be added to the Member Representatives Committee through this selection process until the Member Representatives Committee includes a number of Canadian voting representatives equal to the percentage of the NEL of Canada to the total NEL of the United States and Canada, times the total number of voting members on the Member Representatives Committee, rounded up to

the next whole number. Provided, that no more than one such additional Canadian voting representative shall be selected from a sector, except that if this limitation precludes the addition of the number of additional Canadian voting representatives required by the previous sentence, then no more than two Canadian voting representatives may be selected from the same sector. Such additional Canadian voting representatives shall be representatives of the sectors in which they stood for election, and shall serve terms expiring at the next annual meeting of the Member Representatives Committee pursuant to Section 7 of this Article VIII. For purposes of this Section 4, "Canadian" means one of the following: (a) a company or association incorporated or organized under the laws of Canada or of a province of Canada that is a member of the Corporation, or its designated representative irrespective of nationality; (b) an agency of a federal, provincial, or local government in Canada that is a member of the Corporation, or its designated representative irrespective of nationality; or (c) a person who is a Canadian citizen residing in Canada and is a member of the Corporation.

When the Corporation receives recognition from appropriate governmental authorities in Mexico as the electric reliability organization, this provision will be expanded to provide for adequate representation of Mexican interests on the Member Representatives Committee.

Section 5 — Officers of the Member Representatives Committee — At the initial meeting of the Member Representatives Committee, and annually thereafter prior to the annual election of representatives to the Member Representatives Committee, the Member Representatives Committee shall select a chairman and vice chairman from among its voting members by majority vote of the members of the Member Representatives Committee to serve as chairman and vice chairman of the Member Representatives Committee during the upcoming year; provided, that the incumbent chairman and vice chairman shall not vote or otherwise participate in the selection of the incoming chairman and vice-chairman. The newly selected chairman and vice chairman shall not have been representatives of the same sector. Selection of the chairman and vice chairman shall not be subject to approval of the board. The chairman and vice chairman, upon assuming such positions, shall cease to act as representatives of the sectors that elected them as representatives to the Member Representatives Committee and shall thereafter be responsible for acting in the best interests of the members as a whole.

Section 6 — Vacancies on the Member Representatives Committee — In the event that any member of the Member Representatives Committee ceases to serve as a member of the Member Representatives Committee as a result of his or her death, resignation, retirement, disqualification, or removal or other cause, the members in the sector of which such member was a representative shall elect, as soon thereafter as reasonably possible, and in accordance with the procedures in Sections 3 and 4 of this Article VIII, a new member to replace the member of the Member Representatives Committee who ceases to serve. Except with regard to the selection of the chairman and vice chairman at the initial meeting of the Member Representatives Committee, the vacancies in the sector representatives created by the selection of the chair and vice chair pursuant to Section 5 of this Article VIII shall be filled at the annual election of representatives to the Member Representatives Committee that is next held following the election of the chairman and vice chairman. In the case of the selection of the chairman and vice chairman at the initial meeting of the Member Representatives

Committee, the sector representative vacancies created thereby shall be filled as soon thereafter as reasonably possible in accordance with the procedures in Section 3 of this Article VIII for sector representative vacancies.

Section 7 — Annual Meeting of the Member Representatives Committee — An annual meeting of the Member Representatives Committee for the election of independent trustees and to conduct such other business as may come before the meeting shall be held on or about February 1 of each year or as soon thereafter as is reasonably possible. By resolution adopted at any meeting of the Member Representatives Committee, the Member Representatives Committee may provide for additional regular meetings that may be held without further notice to the members of the Member Representatives Committee.

Section 8 — Special Meetings of the Member Representatives Committee — Special meetings of the Member Representatives Committee for any purpose or purposes may be called by the chair of the Member Representatives Committee or by any five (5) members of the Member Representatives Committee, which number shall include representatives from at least three sectors, and require notice given to all members of the Member Representatives Committee not less than seven (7) days prior to the date of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, telegraph, or other electronic media, or by express delivery.

Section 9 — Quorums and Voting for Meetings of the Member Representatives Committee — The quorum necessary for the transaction of business at meetings of the Member Representatives Committee shall be two-thirds of the voting members of the Member Representatives Committee attending the meeting in person or by proxy. A member of the Member Representatives Committee may give a proxy only to a person who is a member, or an officer, executive-level employee, agent or representative of a member, registered in the same sector. Each voting member of the Member Representatives Committee shall have one (1) vote on any matter coming before the Member Representatives Committee that requires a vote. Except as otherwise expressly provided in the Corporation's Certificate of Incorporation, these Bylaws or applicable law, actions by members of the Member Representatives Committee shall be approved upon receipt of the affirmative vote of a majority of the voting members of the Member Representatives Committee present and voting, in person or by proxy, at any meeting at which a quorum is present.

Section 10 — Meetings of the Member Representatives Committee to be Open — Notice to the public of the dates, places, and times of meetings of the Member Representatives Committee, and all nonconfidential material provided to the Member Representatives Committee, shall be posted on the Corporation's Web site, and notice of meetings of the Member Representatives Committee shall be sent electronically to all members of the Corporation, within 24 hours of the time that notice or such material is given to the Member Representatives Committee. Meetings of the Member Representatives Committee shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the Member Representatives Committee may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity. Any or all members of, and any other

participants in, the Member Representatives Committee may participate in a meeting of the Member Representatives Committee by a means of a communications system by which all persons participating in the meeting are able to hear each other.

Section 11 — Waivers of Notice of Meetings of the Member Representatives Committee; and Meeting Adjournments — Notice of a meeting of the Member Representatives Committee need not be given to any member of the Member Representatives Committee who signs a waiver of notice, in person or by proxy, whether before or after the meeting, or who attends the meeting without protesting, prior to the conclusion of the meeting, the lack of notice of such meeting. Notice of an adjourned meeting of the Member Representatives Committee need not be given if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if the period of adjournment does not exceed ten (10) days.

Section 12 — Action Without a Meeting of the Member Representatives Committee — Any action required or permitted to be taken at a meeting of the Member Representatives Committee may be taken by the Member Representatives Committee without a meeting if the action is consented to in writing by the number of members of the Member Representatives Committee entitled to vote on the action that would be required to approve the action at a meeting of the Member Representatives Committee with all of its members present. The call for action without a meeting of the Member Representatives Committee may be initiated by the Chair of the Member Representatives Committee or by any five (5) members of the Member Representatives Committee, which number shall include representatives from at least three (3) sectors. Notice of the proposed call for action without a meeting, and all nonconfidential material provided to the Member Representatives Committee in connection with the call for action without a meeting, shall be posted on the Corporation's Web site within 24 hours of the time notice of the call for action without a meeting or such material is provided to the members of the Members Representative Committee. The members of the Member Representatives Committee shall receive written notice of the results, and the results shall be posted on the Corporation's Web site, within seven (7) days of the action vote, and all written responses of voting members of the Member Representatives Committee shall be filed with the minutes of the Corporation.

Section 13 — Other Procedures of the Member Representatives Committee — The chairman of the board in office on November 1, 2006, shall preside at the initial meeting of the Member Representatives Committee, until a chairman is selected in accordance with Section 5 of this Article VIII. Except as to any matter as to which the procedure to be followed by the Member Representatives Committee is expressly set forth in these Bylaws, the Member Representatives Committee may adopt such additional procedures, not inconsistent with these Bylaws, as it deems appropriate.

ARTICLE IX
Reliability Standards

Section 1 — Development of Reliability Standards — The Corporation shall develop, implement and, in all regions in which necessary governmental approvals have been obtained or authority has been provided, enforce, reliability standards that provide for reliable operation of the bulk power systems of North America. All reliability standards shall be approved by the board. All reliability standards of the Corporation shall be posted on its Web site. Nothing in this Article shall be deemed to invalidate any standard of the Corporation that was in effect on November 1, 2006.

Section 2 — Procedures for Development of Reliability Standards —The Corporation shall develop reliability standards pursuant to procedures and processes that shall be specified in the Rules of Procedure of the Corporation. The Rules of Procedure shall provide for the development of reliability standards through an open, transparent, and public process that provides for reasonable notice and opportunity for public comment, due process, and balancing of interests and is designed to result in reliability standards that are technically sound. Participation in the process for development of 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 bulk power system.

Section 3 — Procedures for Determinations of Violations of Reliability Standards and Imposition of Sanctions for Violations — In all regions in which regulatory approval has been obtained or governmental authority has been provided, the Corporation shall consider and make determinations that an owner, operator, or user of the bulk power system has violated a reliability standard, and shall impose sanctions for such violations, pursuant to procedures and processes that shall be specified in the Rules of Procedure of the Corporation. Such procedures and processes shall provide for reasonable notice and opportunity for hearing. Any sanction imposed for a violation of a reliability standard shall bear a reasonable relation to the seriousness of the violation and shall take into consideration efforts of the owner, operator, or user of the bulk power system to remedy the violation in a timely manner. Subject to any necessary action by any applicable governmental authorities, no sanction imposed for a violation of a reliability standard shall take effect until the thirty-first (31) day after the Corporation, where authorized by law or agreement, files with the Commission or other applicable governmental authority notice of the sanction and the record of the proceedings in which the violation and sanction were determined, or such other date as ordered by the Commission or other applicable governmental authority or as prescribed by applicable law.

ARTICLE X
Agreements with Regional Entities

Section 1 — Delegation Agreements with Regional Entities — The Corporation may, in accordance with appropriate governmental authority, enter into agreements with regional entities pursuant to which a regional entity shall be delegated the authority of the Corporation to enforce reliability standards within a geographic region of North America and may develop and propose reliability standards to be in effect within such region. All delegation agreements with regional entities shall be approved by the board. No delegation agreement

with a regional entity shall be effective with respect to a region until the agreement has received any necessary approval from an applicable governmental authority.

Section 2 — Standards for Delegation Agreements — The Corporation shall be permitted to enter into a delegation agreement with a regional entity only if the board determines that (i) the regional entity has agreed to promote, support, and comply with the purposes and policies of the Corporation as set forth in its Certificate of Incorporation, Bylaws, Rules of Procedure, and Reliability Standards as from time to time adopted, approved, or amended; (ii) the regional entity satisfies the criteria set forth in Sections 39.3(b) and 39.8 of the Commission's regulations, or other criteria specified by applicable governmental authorities, and (iii) the delegation agreement will promote effective and efficient administration of the reliability of the bulk power system.

ARTICLE XI
Rules of Procedure

Section 1 — Development of Rules of Procedure — The Corporation shall develop and implement such Rules of Procedure as in the judgment of the board are necessary or appropriate to carry out the purposes of the Corporation and to govern its operations, including without limiting the foregoing, Rules of Procedure relating to (i) registration of owners, operators, and users of the bulk power system; (ii) development of reliability standards; (iii) procedures for standing committees of the Corporation, subgroups of standing committees, and other committees, subcommittees, task forces, and sector-specific forums of the Corporation; (iv) critical infrastructure protection; (v) conduct of readiness evaluations and reliability assessments; (vi) enforcement of compliance with reliability standards and determinations of violations of reliability standards by owners, operators, and users of the bulk power system; (vii) impositions of sanctions for violations of reliability standards; (viii) development, implementation, and administration of delegation agreements with regional entities; (ix) personnel certification; (x) event analysis and information exchange; (xi) realtime monitoring of the bulk power system; and (xii) development and administration of budgets, business plans, and funding mechanisms of the Corporation. All Rules of Procedure of the Corporation shall be posted on its Web site.

Section 2 — Adoption, Amendment, and Repeal of Rules of Procedure — Except as provided in Section 2 of Article XII, all Rules of Procedure, amendments thereto and repeals thereof shall be approved by the board. Proposals to adopt new Rules of Procedure or to amend or repeal existing Rules of Procedure may be submitted by (i) the Member Representatives Committee, (ii) any fifty (50) members of the Corporation, which number shall include members in at least three sectors, (iii) a committee of the Corporation to whose purpose and functions the Rule of Procedure pertains, or (iv) an officer of the Corporation. Unless the board determines that exigent conditions exist requiring adoption of a new Rule of Procedure or amendment or repeal of an existing Rule of Procedure in a shorter time, all proposals for adoption, amendment and repeal of Rules of Procedure shall be posted on the Corporation's Web site and subject to public comment for a minimum of forty-five (45) days prior to action by the board. All Rules of Procedure and amendments to and repeals of Rules of Procedure approved by the board shall be submitted to the Commission and to other

applicable governmental authorities for approval, and shall not be effective in the United States until approved by the Commission or in Canada or Mexico until approval is obtained from any governmental authority from which approval is required in those countries and subject to any conditions, limitations, or modifications required by the Commission or other governmental authority. Nothing in this Article shall be deemed to invalidate any Rule of Procedure of the Corporation that was in effect on November 1, 2006.

ARTICLE XII
Personnel Certification Governance Committee

Section 1 — Personnel Certification Governance Committee — There shall be a Personnel Certification Governance Committee of the Corporation, which shall be a standing committee of the Corporation. The purpose of the Personnel Certification Governance Committee shall be to provide oversight to the policies and processes used to implement and maintain the integrity and independence of the Corporation's System Operator Certification Program. The governance authority and structure of the Personnel Certification Governance Committee shall be implemented and maintained so that policies and procedures are established to protect against undue influence that could compromise the integrity of the System Operator Certification process.

Section 2 — Appointment and Reporting of the Personnel Certification Governance Committee — The members of the Personnel Certification Governance Committee shall be appointed by the board from candidates selected and presented by a nominating task force in accordance with Rules of Procedure for the Personnel Certification Governance Committee. Nominations and appointments shall take into account the need to include representatives of all geographic regions of North America on the Personnel Certification Governance Committee. The Personnel Certification Governance Committee shall report directly to the board and the president of the Corporation regarding governance and administration of the System Operator Certification Program; provided, however, that the Personnel Certification Governance Committee shall have autonomy in developing and implementing system operator certification eligibility requirements, the development, administration, and scoring of the system operator assessment instruments, and operational processes for the System Operator Certification Program. The Personnel Certification Governance Committee shall provide to the board periodic assessments, no less frequently than every two (2) years, of the effectiveness of the System Operator Certification Program.

Section 3 — Administration of the Personnel Certification Governance Committee — In order to maintain the independence of the Personnel Certification Governance Committee, staff of the Corporation shall administer the System Operator Certification program on behalf of the Personnel Certification Governance Committee on a fee for service basis.

ARTICLE XIII
Budgets and Funding

Section 1 — Compensation of the Board and Member Representatives Committee — The board shall have the right to fix from time to time, by resolution adopted by a majority of the independent trustees then serving as trustees, the amount of the annual retainer fee or other compensation to be paid to the independent trustees for their services to the Corporation, including any fees to be paid for each meeting of the board or any board committee attended by an independent trustee. No compensation shall be paid to the management trustee for his or her services on the board, other than the compensation paid to the management trustee for services as president of the Corporation. No compensation shall be paid by the Corporation to the members of the Member Representatives Committee for their services on the Member Representatives Committee.

Section 2 — Preparation and Adoption of Annual Budget, Business Plan, and Funding Mechanism — The board shall prepare or cause to be prepared an annual budget for the administrative and other expenses of the Corporation, including the expenditures for the fiscal year for any material special projects undertaken by the Corporation and reasonable and proper reserves and provisions for contingencies, an accompanying business plan for the Corporation, and a funding mechanism, for each fiscal year. The annual budget, business plan, and funding mechanism of the Corporation shall be for a fiscal year commencing on January 1 and ending on December 31. Each annual budget, business plan, and funding mechanism (including the annual budget, annual business plan, and annual funding mechanism for each regional entity) shall be approved by the board at a regular meeting or a special meeting of the board duly called for that purpose. The board shall approve each annual budget, business plan, and funding mechanism at least 135 days before the start of the fiscal year in order to allow for timely submittal of the approved annual budget, business plan, and funding mechanism to the applicable governmental authorities.

Section 3 — Criteria for Funding Mechanisms — The annual funding mechanism shall be designed to recover, over the course of the fiscal year, the sum of (i) the annual budget, (ii) less revenues projected to be received by the Corporation from other sources such as sales of services and materials and registration, application and certification fees for programs conducted or administered by the Corporation, and (iii) plus or minus the estimated deficiency or excess of the Corporation's revenues compared to its expenditures for the current fiscal year. The annual funding mechanism shall consist of such assessments as determined by the 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.

Section 4 — Consultation in Preparation of Annual Budget, Business Plan, and Funding Mechanism — In preparing the annual budget, business plan, and funding mechanism, the board shall consult with the members of the Member Representatives Committee, and shall post a draft budget and business plan for review and comment by the members of the Corporation and the Member Representatives Committee and the standing committees of the Corporation for at least thirty (30) days prior to the date of the meeting of the board at which the annual budget, business plan, and funding mechanism are to be adopted.

Section 5 — Modified or Supplemental Funding Mechanisms — During the course of a fiscal year, the board may modify the approved funding mechanism or develop and approve a supplemental funding mechanism if determined by the board to be necessary due to such factors as a shortfall in revenues of the Corporation from projected levels, incurred or anticipated expenditures or new projects not provided for in the annual budget, or such other factors as in the judgment of the board warrant modification of the funding mechanism for the fiscal year or development of a supplemental funding mechanism. In preparing a modified or supplemental funding mechanism, the board shall follow the provisions of Section 4 of this

Article XIII to the extent possible in the judgment of the board in light of the exigency of the circumstances necessitating preparation and approval of the modified or supplemental funding mechanism. Each modified or supplemental funding mechanism shall be approved by the board at a regular meeting or a special meeting of the board duly called for that purpose.

Section 6 — Submission of Annual Budgets, Business Plans, and Funding Mechanisms to the Governmental Authorities — Each annual budget, annual business plan, and annual, modified, or supplemental funding mechanism approved by the board (including the annual budget, annual business plan, and annual, modified, or supplemental funding mechanism for each regional entity) shall be submitted by the Corporation to the applicable governmental authorities for approval in accordance with its regulations, except as otherwise provided by applicable law or by agreement, and shall not be effective until it has received any necessary approval by the applicable governmental authorities. If a governmental authority by order modifies or remands an annual budget, business plan, or annual, modified, or supplemental funding mechanism, the board shall promptly following such order adopt such modifications to the budget, business plan, or funding mechanism as are required or directed by the order of the governmental authority.

ARTICLE XIV
Amendments to the Bylaws

Section 1 — Amendments to the Bylaws — These Bylaws may be altered, amended, or repealed by a majority vote of both the board and the Member Representatives Committee at respective meetings of the board and the Members Representative Committee at which a quorum is present. Written notice of the subject matter of the proposed changes to the Bylaws shall be provided, as appropriate, to the trustees or to the Member Representatives Committee not less than ten (10) nor more than sixty (60) days prior to the date of the meeting of the board or of the Member Representatives Committee at which the vote is to be taken. Notwithstanding the provisions of this Article XIV, the members of the Corporation voting by sector shall have the right to alter, amend, or repeal Bylaws adopted by the board and the Member Representatives Committee and to adopt new Bylaws, provided that any such alteration, amendment, or repeal or the adoption of new Bylaws is approved by vote of two-thirds of the sectors at a meeting of Members called for that purpose, or by written consent of two-thirds of the sectors, where the number of votes for and against the proposed alteration, amendment, repeal, or adoption of Bylaws shall be determined in accordance with Section 2 of Article IV. Any alteration, amendment, repeal, or adoption of Bylaws shall be subject to

any applicable requirements for filing with or approval by the Commission and any other applicable governmental authority.

ARTICLE XV
General

Section 1 — Indemnification — The Corporation shall indemnify its officers, trustees and other corporate agents to the full extent from time to time permitted by the New Jersey Nonprofit Corporation Act and other applicable law. Such right of indemnification shall inure to the benefit of the legal representative of any such person. The foregoing indemnification shall be in addition to, and not in restriction or limitation of, any privilege or power that the Corporation may have with respect to the indemnification or reimbursement of its trustees, officers, or other corporate agents. The Corporation shall also pay or advance expenses incurred by an officer, trustee, or other corporate agent in connection with a proceeding in advance of the final disposition of the proceeding upon receipt of an undertaking by or on behalf of the officer, trustee, or other corporate agent to repay the amount unless it shall be ultimately determined that the officer, trustee, or other corporate agent is entitled to be indemnified by the Corporation.

Section 2 — Parliamentary Rules — In the absence of and to the extent not inconsistent with specific provisions in these Bylaws, meetings or other actions pursuant to these Bylaws shall be governed by procedures that the board may, from time to time, establish by resolution.

Section 3 — Dissolution — Upon dissolution of the Corporation, in accordance with paragraph TENTH of the Certificate of Incorporation, the remaining assets of the Corporation after payment of debts shall be distributed in the manner determined by the board, provided, (i) that no part of the assets shall be distributed to any trustee of the Corporation, and (ii) that the distribution of assets shall be consistent with the requirements of Section 501(c)(6) of the United States Internal Revenue Code of 1986, as amended.

ATTACHMENT 2

Amended North American Electric Reliability Corporation Bylaws – **Redline**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Bylaws

Approved by the Board of Trustees: ~~August 5, 2009~~February 8, 2018 Effective: ~~October 14, 2009~~[Proposed Date]

BYLAWS

OF THE

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ARTICLE I
Definitions

Section 1 — Definitions — As used in these Bylaws of the North American Electric Reliability Corporation (hereinafter referred to as "the Corporation"), the terms set forth in this Article I shall have the meanings set forth herein.

"Applicable governmental authority" means the Federal Energy Regulatory Commission within the United States and the appropriate governmental authority with subject matter jurisdiction over reliability within Canada and Mexico.

"Board" means the Board of Trustees of the Corporation.

"Bulk power system" means facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and 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.

"Commission" means the Federal Energy Regulatory Commission.

"Electric reliability organization" or "ERO" means the organization that is certified by the Commission under Section 39.3 of its regulations, the purpose of which is to establish and enforce Reliability Standards for the bulk power system in the United States. The organization may also have received recognition by applicable governmental authorities in Canada and Mexico to establish and enforce reliability standards for the bulk power systems of the respective countries.

"Member" means a member of the Corporation pursuant to Article II of these Bylaws.

"Net Energy for Load (NEL)" means 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 storage of energy at energy storage facilities. Calculations of net energy for load for all purposes under these Bylaws shall be based on the most recent calendar year for which data on net energy for load of applicable regions of the United States, Canada, and Mexico is available.

"Regional entity" means an entity having enforcement authority pursuant to 18 C.F.R. § 39.8.

"Reliability standard" means a requirement to provide for reliable operation of the bulk power system, including without limiting the foregoing requirements for the operation of existing bulk power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary for reliable operation of the bulk power system, but shall not include any requirement to enlarge bulk power system facilities or to construct new transmission capacity or generation capacity.

"Reliable operation" means operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of the bulk power system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

"Sector" means a group of members of the Corporation that are bulk power system owners, operators, or users or other persons and entities with substantially similar interests, including governmental entities, as pertinent to the purposes and operations of the Corporation and the operation of the bulk power system, as defined in Article II, Section 4 of these Bylaws. Each sector shall constitute a class of members for purposes of the New Jersey Nonprofit Corporation Act.

Section 2 — Additional Defined Terms — Additional terms not defined in this Article I are defined in the remainder of these Bylaws.

Section 3 — Technical Terms — Technical terms not defined in these Bylaws shall have the definitions set forth in the Federal Power Act, Part 39 of the regulations of the Commission, or the "Glossary of Terms Used in Reliability Standards", in that order of precedence, and if not defined in any of those sources, shall be defined in accordance with their commonly understood and used technical meaning in the electric power industry, including applicable codes and standards.

ARTICLE II
Membership

Section 1 — Members — Membership in the Corporation is voluntary and is open to any person or entity that has an interest in the reliable operation of the North American bulk power system and that registers with the Corporation as a member, maintains its registration in accordance with this Article II, and complies with the other conditions and obligations of membership specified in these Bylaws. Membership in a regional entity shall not be a condition for membership in the Corporation. The secretary of the Corporation shall maintain a roster of the members of the Corporation.

Section 2 — Registration as a Member — Any person or entity that is eligible to be a member of the Corporation in accordance with Article II, Section 1 may become a member by completing, and submitting to the secretary of the Corporation, a membership registration on a form prescribed by the board. If not a natural person, the member shall designate a

representative and an alternative representative with authority to receive notices, cast votes, and execute waivers and consents on behalf of the member. The secretary of the Corporation shall maintain a current roster of the members of the Corporation including each member's designated representative and alternative representative. From time to time, the board shall establish a date by which members shall submit their registration renewals. All members shall be required to renew their registrations within 30 calendar days of a request by the secretary of the Corporation, using a registration renewal form prescribed by the board. The secretary of the Corporation shall remove from the roster of members of the Corporation any member that has not submitted a registration renewal within 30 days following a date established by the board. The secretary shall notify any member that is removed from the roster of members of such removal, by notice sent to such former member's last known address on the records of the Corporation.

Section 3 — Obligations and Conditions of Membership

a. Each member shall agree, in writing, to accept the responsibility to promote, support, and comply with the purposes and policies of the Corporation as set forth in its Certificate of Incorporation, Bylaws, Rules of Procedure, and Reliability Standards as from time to time adopted, approved, or amended.

b. As an additional condition of membership in the Corporation, each person or entity registering as a member shall be required to execute an agreement with the Corporation, in a form to be specified by the board, that such person or entity will hold all trustees, officers, employees, and agents of the Corporation, as well as volunteers participating in good faith in the activities of the Corporation, harmless, to the extent permitted by Federal or provincial laws, regulations and rules, for any injury or damage to that member caused by any act or omission of any trustee, officer, employee, agent, or volunteer in the course of performance of his or her duties on behalf of the Corporation, other than for acts of gross negligence, intentional misconduct, or a breach of confidentiality.

Section 4 — Membership Sectors

a. Each member shall elect to be assigned to one of the following membership sectors: (i) investor-owned utility; (ii) state/municipal utility; (iii) cooperative utility; (iv) federal or provincial utility/power marketing administration; (v) transmission-dependent utility; (vi) merchant electricity generator; (vii) electricity marketer; (viii) large end-use electricity customer; (ix) small end-use electricity customer; (x) independent system operator/regional transmission organization; (xi) regional entity; or (xii) government representatives. The composition of each sector shall be as follows:

    i. Investor-owned utility — This sector includes any investor-owned entity with a substantial business interest in ownership and/or operation in any of

the asset categories of generation, transmission or distribution. This sector also includes organizations that represent the interests of such entities.

ii. State/municipal utility — This sector includes any entity owned by or subject to the governmental authority of a state or municipality, that is engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the state or municipality; and any entity, whose members are municipalities, formed under state law for the purpose of generating, transmitting, or purchasing electricity for sale at wholesale to their members. This sector also includes organizations that represent the interests of such entities.

iii. Cooperative utility — This sector includes any non-governmental entity that is incorporated under the laws of the state in which it operates, is owned by and provides electric service to end-use customers at cost, and is governed by a board of directors that is elected by the membership of the entity; and any non-governmental entity owned by and which provides generation and/or transmission service to such entities. This sector also includes organizations that represent the interests of such entities.

iv. Federal or provincial utility/Federal Power Marketing Administration — This sector includes any U.S. federal, Canadian provincial, or Mexican entity that owns and/or operates electric facilities in any of the asset categories of generation, transmission, or distribution; or that functions as a power marketer or power marketing administrator. This sector also includes organizations that represent the interests of such entities.

v. Transmission-dependent utility — This sector includes any entity with a regulatory, contractual, or other legal obligation to serve wholesale aggregators or customers or end-use customers and that depends primarily on the transmission systems of third parties to provide this service. This sector also includes organizations that represent the interests of such entities.

vi. Merchant electricity generator — This sector includes any entity that owns or operates an electricity generating facility that is not included in an investor-owned utility's rate base and that does not otherwise fall within any of sectors (i) through (v). This sector includes but is not limited to cogenerators, small power producers, and all other nonutility electricity producers such as exempt wholesale generators who sell electricity at wholesale. This sector also includes organizations that represent the interests of such entities.

vii. Electricity marketer — This sector includes any entity that is engaged in the activity of buying and selling of wholesale electric power in North America

on a physical or financial basis. This sector also includes organizations that represent the interests of such entities.

viii. Large end-use electricity customer — This sector includes any entity in North America with at least one service delivery taken at 50 kV or higher (radial supply or facilities dedicated to serve customers) that is not purchased for resale; and any single end-use customer with an average aggregated service load (not purchased for resale) of at least 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations that represent the interests of such entities.

ix. Small end-use electricity customer — This sector includes any person or entity within North America that takes service below 50 kV; and any single end-use customer with an average aggregated service load (not purchased for resale) of less than 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations (including state consumer advocates) that represent the interests of such entities.

x. Independent system operator/regional transmission organization — This sector includes any entity authorized by the Commission to function as an independent transmission system operator, a regional transmission organization, or a similar organization; comparable entities in Canada and Mexico; and the Electric Reliability Council of Texas or its successor. This sector also includes organizations that represent the interests of such entities.

xi. Regional entity — This sector includes any regional entity as defined in Article I, Section 1.

xii. Government representatives — This sector includes any federal, state, or provincial government department or agency in North America having a regulatory and/or policy interest in wholesale electricity. Entities with regulatory oversight over the Corporation or any regional entity, including U.S., Canadian, and Mexican federal agencies and any provincial entity in Canada having statutory oversight over the Corporation or a regional entity with respect to the approval and/or enforcement of reliability standards, may be nonvoting members of this sector.

b. A member may elect to be assigned to any sector so long as membership in that sector is consistent with the member's business or other activities. A corporation and its affiliates shall be considered a single member and may register in only one sector, which may be any single sector for which the corporation or any of its affiliates is eligible. A consultant, attorney, agent, vendor, trade or industry association, state, provincial or local consumer advocate organization that provides services to or

otherwise represents the interests of the members of one or more sectors may elect to be assigned to one such sector.

Section 5 — Term of Membership — Membership in the Corporation shall be retained as long as a member meets its respective qualifications, obligations, and conditions of membership as set forth in this Article II.

Section 6 — Removal — In addition to termination of membership in accordance with Article II, Section 2, the board, following notice to the member and exercise of appropriate due process procedures, may terminate the membership of a member if in the judgment of the board that member has violated its obligations and responsibilities to the Corporation. This termination shall require a two-thirds vote of the trustees present and voting at a meeting of the board at which a quorum of the board entitled to vote is present. Within thirty (30) days following the action of the board terminating the membership of a member, the member shall be entitled to appeal such termination to the Commission or to the applicable governmental authority in Canada or Mexico.

ARTICLE III
Board of Trustees

Section 1 — Board of Trustees — The business and affairs of the Corporation shall be managed by a Board of Trustees. The board shall consist of eleven members (the "trustees"), unless it is increased to twelve members pursuant to Section 1a of this Article III. All but one of the trustees shall be "independent" trustees nominated and elected in accordance with the requirements and procedures specified in Sections 2, 3, 4, 5, and 6 of this Article III (the "independent trustees"). The remaining trustee shall be the person elected by the board, in accordance with Article VI, Section 1, of these Bylaws, to serve as president of the Corporation (the "management trustee"). Each trustee, including the management trustee, shall have one (1) vote on any matter brought before the board for a vote. All trustees are expected to serve the public interest and to represent the reliability concerns of the entire North American bulk power system.

Section 1a — Increase in number of trustees — The board shall have the authority, by resolution, to increase the number of trustees from eleven to twelve, of which eleven trustees shall be independent trustees, with such increase to be effective as of the date of an annual election of independent trustees pursuant to Section 6 of this Article III. In order for the board to exercise this authority, the resolution increasing the number of trustees from eleven to twelve must be adopted by the board no later than December 1 immediately preceding the date of the annual election of independent trustees at which the increase is to be effective, and shall state a determination by the board that the increase is in the best interests of the Corporation and its Members. If the board adopts a resolution increasing the number of trustees from eleven to twelve, the nominating committee appointed pursuant to Section 5 of this Article III shall nominate a candidate to stand for election to the newly-created independent trustee position at the next annual election of independent trustees, along with candidates for the positions of independent trustees whose terms are expiring as of such election. The newly-created independent trustee position shall be filled by election in accordance with Section 6 of this Article III. Upon election of a trustee to the newly-created independent trustee position, the

board shall thereafter consist of twelve trustees, of whom eleven shall be independent trustees and one shall be the management trustee provided for in Section 1 of this Article III, unless the board decreases the number of trustees in accordance with Section 1b of this Article III.

Section 1b — Decrease in number of trustees — If the board has previously increased the number of trustees under Section 1a of this Section III, the board shall have the authority, by resolution, to decrease the number of trustees from twelve to eleven, of which ten trustees shall be independent trustees, with such decrease to be effective as of the date of an annual election of independent trustees pursuant to Section 6 of this Article III. The decrease in number of trustees shall be effected by eliminating one of the independent trustee positions whose term is expiring as of the date of such annual election of trustees, in which case no election shall be held to replace such trustee. In order for the board to exercise this authority, the resolution decreasing the number of trustees from twelve to eleven must be adopted by the board no later than September 1 immediately preceding the date of the annual election of independent trustees at which the decrease is to be effective; shall identify the independent trustee position expiring at the date of such annual election that shall be eliminated; and shall state a determination by the board that the decrease is in the best interests of the Corporation and its Members.

Section 2 — Composition of Board Based on Country Participation

a. The board shall consist of a number of trustees from the United States and from Canada. The number of trustees from Canada shall not be less than the percentage of the NEL of Canada to the total NEL of the United States and Canada, times eleven (or times twelve if the number of trustees has been increased to twelve pursuant to Section 1a of this Article III), rounded up to the nearest whole number. For purposes of this board composition requirement, the management trustee shall be counted as a trustee from Canada if he or she is a Canadian citizen.

b. When the Corporation receives recognition by appropriate regulatory authorities in Mexico as its electric reliability organization, the number of independent trustees will be increased by at least one, and the board composition requirement in subsection (a) will be expanded to include Mexico.

Section 3 — Independent Board Members — The independent trustees shall be elected, shall have the qualifications specified, and shall serve in the manner provided in this section.

a. An independent trustee is a person (i) who is not an officer or employee of the Corporation, 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.

b. Independent trustees shall be elected to terms expiring at the annual election of independent trustees occurring in the third year after their election. As of the original effective date of these Bylaws, the independent trustees of the Corporation and the date the term of each independent trustee expires were as follows:

Name	**Term Expires**
John Q. Anderson	2007
Paul F. Barber	2008
Thomas W. Berry	2007
Richard Drouin	2009
James M. Goodrich	2008
Donald P. Hodel	2008
Sharon L. Nelson	2007
Bruce A. Scherr	2009
Kenneth G. Peterson	2009
Fred Gorbet	2008

c. Independent trustees shall be nominated and elected pursuant to the nomination and election procedures specified in Sections 4, 5, and 6 of this Article III.

Section 4 — Vacancies on the Board —Should any vacancy on the board arise from the death, resignation, retirement, disqualification, or removal from office of any independent trustee, or from any other cause, such vacancy shall be filled by electing a trustee at the next annual election of trustees to fill the remainder, if any, of the term of the departed trustee. Provided, that the board by resolution may in its discretion call a special election to fill any such vacancy for the remainder, if any, of the term of the departed trustee. Any vacancy shall be filled so as to maintain the composition of the board in accordance with country participation pursuant to Section 2 of this Article III.

Section 5 — Nominating Committee — The board shall appoint, on an annual basis, or more frequently if needed in the event of a special election pursuant to Article III, Section 4, a nominating committee (the "nominating committee") to recommend candidates (i) to succeed the independent trustees whose terms expire during the current year and (ii) to serve the remainder of the term of any independent trustee who ceased to serve as a trustee subsequent to the last annual election of trustees. The nominating committee shall 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, provided, that the nominating committee shall be chaired by an independent trustee whose term does not expire during the current year and shall include at least three persons who are also members of the Member Representatives Committee, and provided further, that the nominating committee

formed for the purpose of recommending candidates to stand for election as trustees at the election to be held on or about February 1, 2007, pursuant to Article III, Section 6 shall not include any members of the Member Representatives Committee but shall include three

persons each of whom at the time of his or her appointment by the chair of the Stakeholders Committee of the North American Electric Reliability Council to the nominating committee shall be a member of that Stakeholders Committee. The board shall establish, by resolution, the procedures to be followed by the nominating committee in identifying and recommending candidates to serve as independent trustees; provided, however, that such procedures shall include a means of permitting members of the Corporation to recommend to the nominating committee candidates for consideration as nominees for independent trustees. The nominating committee shall nominate candidates for election to the board consistent with the requirements of Article III, Section 2 for board composition by country participation, and 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 operation issues; and reflects geographic diversity.

Section 6 — Election of Independent Trustees — The Member Representatives Committee of the Corporation shall elect the persons (i) to succeed those independent trustees whose terms expire each year and (ii) to serve the remainder of the term of any independent trustee who ceased to serve as a trustee subsequent to the last annual election of independent trustees. The annual election of independent trustees shall be scheduled to be conducted on or about February 1 of each year or as soon thereafter as is reasonably possible. Any special election pursuant to Article III, Section 2 shall be held as expeditiously as possible consistent with the time required for a nominating committee to be appointed and to nominate one or more candidates for the special election. All independent trustees shall be elected from nominees proposed by the nominating committee. A nominee shall be elected an independent trustee if such person receives the affirmative vote of two-thirds of the members of the Member Representatives Committee. Each nominee receiving the necessary two-thirds vote of the Member Representatives Committee shall take office immediately upon election. In the event that the voting fails to elect a nominee to fill any of the positions of independent trustee to be filled in an annual election of independent trustees, the nominating committee shall as promptly as reasonably possible consider and propose one or more additional nominee or nominees for that position, and a vote by the Member Representatives Committee on the election of such nominee or nominees shall be conducted as quickly as possible. For avoidance of doubt, the independent trustees shall be elected by the Member Representatives Committee in accordance with this Section 6 and shall not be elected by vote of the members of the Corporation.

Section 7 — Management Trustee — The president of the Corporation shall be, ex officio, the management trustee of the Corporation, effective as of the date of his or her election by the board as president of the Corporation in accordance with Article VI, Section 1, of these Bylaws, to serve until such time that he or she ceases to hold the position of president.

Section 8 — Committees of the Board — The board shall by resolution create and appoint all committees of the board as the board deems necessary to perform its responsibilities;

provided, that the management trustee shall not be a member of the audit committee or of the human resources committee, if any. All committees of the board shall have such duties as are prescribed by the board. Notice to the public of the dates, places, and times of meetings of

board committees, and all nonconfidential material provided to committee members, shall be posted on the Corporation's Web site within 24 hours of the time that notice is given to committee members. Meetings of board committees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity.

ARTICLE IV
Meetings of Members of the Corporation

Section 1 — Meetings of Members — Meetings of members of the Corporation may be called for any purpose or purposes by the chairman of the board or by a number of members constituting at least ten (10) percent of the members on the roster of members maintained by the secretary of the Corporation, which number shall include members in at least three of the sectors. Meetings of members shall be held at the principal office of the Corporation or at such other place fixed by the board as shall be specified in the notice of meeting. Meetings shall be called upon written notice of the time, date, place, and purposes of the meeting given to all members on the roster of members maintained by the secretary of the Corporation not less than ten (10) nor more than sixty days (60) prior to the date of the meeting.

Section 2 — Quorum and Voting Requirements for Meetings of Members — At any meeting of the members of the Corporation, attendance in person or by proxy by one-half of the members in each of at least two-thirds of the sectors on the roster of members maintained by the secretary of the Corporation shall constitute a quorum. Except as otherwise expressly provided in the Corporation's Certificate of Incorporation, these Bylaws or applicable law, actions by the members of the Corporation shall be approved upon receipt of seven affirmative votes at a meeting of the members of the Corporation at which a quorum is present, where (i) each sector of the Corporation shall have one vote, except that if less than one-half of the members in a sector are present, in person or by proxy, at the meeting, the vote of that sector shall be weighted by a percentage equal to the number of members of the sector present in person or by proxy at the meeting divided by one-half of the members in the sector; (ii) the vote of each sector of the Corporation shall be allocated for and against the proposed action based on the respective percentages of votes cast for and against the proposed action by the members in that sector voting in person or by proxy; and (iii) the proportions of the votes of each sector allocated for and against the proposed action shall be summed to determine the total number of votes for and against the proposed action.

Section 3 — Waivers of Notice of Meetings of Members; and Member Meeting Adjournments — Notice of a meeting of members need not be given to any member who signs a waiver of notice, in person or by proxy, whether before or after the meeting. The attendance of any member at a meeting, in person or by proxy, without protesting prior to the conclusion of the meeting the lack of notice of such meeting, shall constitute a waiver of notice of the meeting by such member. When any meeting of members is adjourned to

another time or place, it shall not be necessary to give notice of the adjourned meeting if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken, and if at the adjourned meeting only such business is transacted as might have been transacted at the original meeting.

Section 4 — Action Without a Meeting of Members — Any action, required or permitted to be taken at a meeting of members, may be taken without a meeting if the action is consented to in writing by the minimum number of members that would be required to approve the action at a meeting of the members at which all members were present. The call for action without a meeting of members may be initiated by the chairman of the board or by a number of members constituting at least ten (10) percent of the members on the roster of members maintained by the secretary of the Corporation, which number shall include members in at least three of the sectors. Notice of the proposal for action without a meeting shall be provided to all members on the roster of members maintained by the secretary of the Corporation at least ten (10) days prior to the date established for the tabulation of consents.
The members shall receive written notice of the results, and the results shall be posted on the Corporation's Web site, within ten (10) days of the action vote, and all written responses of the members shall be filed with the minutes of proceedings of members.

Section 5 — Meetings of the Members to be Open — Notice to the public of the dates, places, and times of meetings of the members, and all nonconfidential material provided to the members, shall be posted on the Corporation's Web site within 24 hours of the time that notice is given to the members. Meetings of the members shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity.

ARTICLE V
Meetings of the Board of Trustees

Section 1 — Regular Meetings of the Board — A regular meeting of the board for such business as may come before the meeting shall be held on or about February 1 of each year. By resolution adopted at any meeting of the board, the board may provide for additional regular meetings that may be held without further notice to the trustees.

Section 2 — Special Meetings of the Board — Special meetings of the board for any purpose or purposes may be called at any time by the chairman or by any two trustees. Such meetings may be held upon notice given to all trustees not less than five (5) days prior to the date of the meeting unless the meeting is a closed session as permitted by Article V, Section 4 of these Bylaws, in which event the notice shall be provided to all trustees not less than 24 hours prior to the date and time of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, telegraph, or other electronic media, or by express delivery.

Section 3 — Quorum and Voting Requirements for Meetings of the Board — Unless otherwise expressly provided in the Corporation's Certificate of Incorporation, these Bylaws or applicable law, (i) the quorum necessary for the transaction of business at meetings of the board shall be a majority of the trustees, and (ii) actions by the board shall be approved upon receipt of the affirmative vote of a majority of the trustees present and voting at a meeting at which a quorum is present.

Section 4 — Meetings of the Board to be Open — Notice to the public of the dates, places, and times of meetings of the board, and all nonconfidential material provided to the board, shall be posted on the Corporation's Web site, and notice of meetings of the board shall be sent electronically to members of the Corporation, within 24 hours of the time that notice or such material is given to the trustees. Meetings of the board shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the board may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity. Any or all of the trustees, or members of a committee, may participate in a meeting of the board, or a meeting of a committee, by means of a communications system by which all persons participating in the meeting are able to hear each other.

Section 5 — Waivers of Notice of Board Meetings; and Board Meeting Adjournments — Notice of a board meeting need not be given to any trustee who signs a waiver of notice, in person or by proxy, whether before or after the meeting, or who attends the meeting without protesting, prior to the conclusion of the meeting, the lack of notice of such meeting. Notice of an adjourned board meeting need not be given if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if the period of adjournment does not exceed ten (10) days.

Section 6 — Action Without a Meeting — Any action, required or permitted to be taken at a meeting of the board or of any committee thereof, may be taken by the board or by the committee without a meeting if the action is consented to in writing by the number of trustees or members of the committee, as the case may be, entitled to vote on the action that would be required to approve the action at a meeting of the board or committee with all members of the board or committee present. The call for action without a meeting of the board may be initiated by the chairman or by any two trustees. Notice of the proposed call for action without a meeting, and all nonconfidential material provided to the board in connection with the call for action without a meeting, shall be posted on the Corporation's Web site within 24 hours of the time notice of the call for action without a meeting or such material is provided to the board. The call for action without a meeting of a committee of the board may be initiated by the chairman or by any two members of the committee. The trustees or members of the committee shall receive written notice of the results, and unless the action was confidential the results shall be posted on the Corporation's Web site, within seven (7) days of the action vote. All written responses of the trustees shall be filed with the minutes of the Corporation, and all written responses of members of a committee shall be filed with the minutes of such committee.

ARTICLE VI
Officers

Section 1 — Officers — At its regular meeting held on or about February 1 of each year in accordance with Section 1 of Article V of these Bylaws, the board shall elect a chairman, a vice chairman, a president, a secretary, a treasurer, an assistant secretary-treasurer, and such other officers of the Corporation (collectively, the "officers") as it shall deem necessary. The chairman and the vice chairman must each be independent trustees prior to their election to such offices. The chairman, vice chairman, and president shall each be nominated and elected by the board. All of the remaining officers shall be appointed or removed by the board based upon the recommendation of the president. The duties and authority of the chairman, the vice chairman, and the president shall be determined from time to time by the board, and the duties and authority of the other officers of the Corporation shall be determined from time to time by the president. Subject to any such determination, the officers shall have the following duties and authority:

a. The chairman shall preside at all meetings of the members and at all meetings of the board. The chairman, in consultation with the other trustees, shall be responsible for the efficient operation of the board and its committees. The chairman shall be an ex officio member of each committee of the board. The chairman may delegate from time to time any or all of the aforesaid duties and authority to the vice chairman, another trustee, the president, or any other officer.

b. The vice chairman shall have such duties and possess such other powers as may be delegated to him or her by the chairman. The vice chairman shall act as the chairman at such times as the chairman may request. In the event the chairman is unable to discharge the duties and powers of that office by reason of incapacity and during any vacancies in the office of the chairman, the vice chairman shall act as chairman until the cessation of such incapacity or the filling of such vacancy.

c. The president shall be the chief executive officer of the Corporation. He or she shall be responsible for the day-to-day ongoing activities of the Corporation and shall have such other duties as may be delegated or assigned to him or her by the chairman. The president may enter into and execute in the name of the Corporation contracts or other instruments not in the regular course of business that are authorized, either generally or specifically, by the board.

d. The secretary shall maintain the roster of members of the Corporation; shall cause notices of all meetings to be served as prescribed in these Bylaws; shall keep or cause to be kept the minutes of all meetings of the members and the board; and shall have charge of the seal of the Corporation. The secretary shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the president.

e. The treasurer shall have custody of the funds and securities of the Corporation, and shall keep or cause to be kept regular books of account for the Corporation. The treasurer shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the president.

f. The assistant secretary-treasurer shall have such duties and possess such other powers as may be delegated to him or her by the president.

ARTICLE VII
Committees of the Corporation

Section 1 — Committees of the Corporation — In addition to those committees specified by these Bylaws, to which the board shall appoint members in accordance with the requirements of these Bylaws, the board may by resolution create standing committees of the Corporation; and may in addition by resolution appoint such other committees as the board deems necessary to carry out the purposes of the Corporation. The board shall appoint standing committees and other committees of the Corporation that are representative of members, other interested parties and the public, that provide for balanced decision making, and that include persons with outstanding technical knowledge and experience. All appointments of committees of the Corporation shall provide the opportunity for an equitable number of members from the United States and Canada (and from Mexico after the Corporation receives recognition by appropriate governmental authorities in Mexico as its electric reliability organization) to be appointed to each committee in approximate proportion to each country's percentage of the total NEL. All committees shall have such scope and duties, not inconsistent with law, as are specified in these Bylaws and the Rules of Procedure of the Corporation or otherwise determined by the board.

ARTICLE VIII
Member Representatives Committee

Section 1 — Member Representatives Committee — The Corporation shall have a Member Representatives Committee that shall have the following rights and obligations:

a. to elect the independent trustees, in accordance with Article III, Section 6;

b. to vote on amendments to the Bylaws, in accordance with Article XIV~~XVI~~; and

c. to provide advice and recommendations to the board with respect to the development of annual budgets, business plans and funding mechanisms, and other matters pertinent to the purpose and operations of the Corporation.

Because it is elected by the members of the Corporation and not appointed by the board, the Member Representatives Committee shall not be a standing committee of the Corporation, but is authorized to provide its advice and recommendations directly to the board.

Section 2 — Composition of the Member Representatives Committee — The Member Representatives Committee shall consist of (i) two representatives from each sector except the government representative sector and the regional entity sector, (ii) two voting representatives from the regional entity sector, with the remaining members of that sector being non-voting members of the Member Representatives Committee, (iii) the chairman and vice chairman of the Member Representatives Committee, (iv) any additional Canadian representatives as are selected pursuant to Section 4 of this Article VIII, and (v) 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 Member Representatives Committee except the two representatives of state governments. The representatives of each sector shall be members of the Corporation, or officers or executive-level employees, agents or representatives of members of the Corporation, in that sector; provided, that at any time only one officer, employee, agent, or representative of a member in a sector may be a representative from that sector. No member of the board shall be a member of the Member Representatives Committee. The board may by resolution create additional nonvoting positions on the Member Representatives Committee at the written request of any group of members of the Corporation that believes its interests are not adequately represented on the Member Representatives Committee.

In order to provide that the terms of approximately one-half of the members of the Member Representatives Committee expire each year, on the initial Member Representatives Committee one-half of the representatives from each sector shall serve a term expiring at the next annual meeting, and one-half of the representatives from each sector shall serve a term expiring at the second succeeding annual meeting, in each case held pursuant to Section 7 of this Article VIII.

Following the expiration of the terms of the members of the initial Member Representatives Committee as provided above, each member of the Member Representatives Committee shall thereafter serve a term of two years commencing at an annual meeting held pursuant to Section 7 of this Article VIII and ending at the second succeeding annual meeting. There shall be no limit on the number of terms that a member of the Corporation, or an employee, agent, or representative of a member of the Corporation, may serve on the Member Representatives Committee.

Section 3 — Election of Members of the Member Representatives Committee

a. Unless a sector adopts an alternative election procedure, the annual election of representatives from each sector to the Member Representatives Committee, and any election to fill a vacancy, shall be conducted in accordance with the following process, which shall be administered by the officers of the Corporation. During the period beginning approximately ninety (90) days and ending approximately thirty (30) days prior to an annual election, or beginning approximately forty-five (45) days and ending approximately fifteen (15) days prior to an election to fill a vacancy, nominations may be submitted for candidates for election to the Member Representatives Committee, provided that for the initial election the period may

begin as soon as these bylaws are made effective and may end approximately fifteen (15) days prior to the election. A nominee for election as a sector representative must be a member, or an officer, executive-level employee or agent of a member, in that sector. No more than one nominee who is an officer, executive-level employee or agent of a member or its affiliates may stand for election in any single sector; if more than one officer, employee or agent of a member or its affiliates is nominated for election from a sector, the member shall designate which such nominee shall stand for election. The election of representatives shall be conducted over a period of ten (10) days using an electronic process. Each member in a sector shall have one vote for each representative to be elected from the sector in that election, and may cast no more than one vote for any nominee. The nominee receiving the highest number of votes in each sector shall be elected to the representative position to be filled from that sector; if there is more than one representative position to be filled from a sector, the nominee receiving the second highest number of votes shall also be elected, and so forth. Provided, that to be elected a nominee must receive a number of votes equal to a simple majority of the members in the sector casting votes in the election. If no nominee in a sector receives a simple majority of votes cast in the first ballot, a second ballot shall be conducted which shall be limited to the number of candidates receiving the two (2) highest vote totals on the first ballot (or to the number of candidates receiving the four (4) highest vote totals on the first ballot if two representative positions remain to be filled, and so forth). The nominee or nominees receiving the highest total or totals of votes on the second ballot shall be elected to the representative position or positions remaining to be filled for the sector.

A sector may adopt an alternative procedure to the foregoing to nominate and elect its representatives to the Member Representatives Committee if (i) the alternative procedure is consistent in principle with the procedures specified in the preceding paragraph of this Section 3a, and (ii) the alternative procedure is approved by vote of at least two-thirds of the members in the sector. Any alternative procedure is subject to review and disapproval by the board.

Section 4 — Adequate Representation of Canadian Interests on the Member Representatives Committee — In addition to the requirements for composition of the Member Representatives Committee specified in Section 1 of this Article VIII, the Member Representatives Committee shall contain a number of Canadian voting representatives equal to the percentage of the NEL of Canada to the total NEL of the United States and Canada, times the total number of voting members on the Member Representatives Committee, rounded up to the next whole number. If the annual selection of members of the Member Representatives Committee pursuant to Section 3 of this Article VIII does not result in the number of Canadian voting representatives provided for herein on the Member Representatives Committee, then the candidate who received the highest fraction of the sector vote among those candidates who would have qualified as Canadian voting representatives but were not elected to the Member Representatives Committee shall be added to the Member Representatives Committee. Additional Canadian voting representatives shall be added to the

Member Representatives Committee through this selection process until the Member Representatives Committee includes a number of Canadian voting representatives equal to the percentage of the NEL of Canada to the total NEL of the United States and Canada, times the total number of voting members on the Member Representatives Committee, rounded up to the next whole number. Provided, that no more than one such additional Canadian voting representative shall be selected from a sector, except that if this limitation precludes the addition of the number of additional Canadian voting representatives required by the previous sentence, then no more than two Canadian voting representatives may be selected from the same sector. Such additional Canadian voting representatives shall be representatives of the sectors in which they stood for election, and shall serve terms expiring at the next annual meeting of the Member Representatives Committee pursuant to Section 7 of this Article VIII. For purposes of this Section 4, "Canadian" means one of the following: (a) a company or association incorporated or organized under the laws of Canada or of a province of Canada that is a member of the Corporation, or its designated representative irrespective of nationality; (b) an agency of a federal, provincial, or local government in Canada that is a member of the Corporation, or its designated representative irrespective of nationality; or (c) a person who is a Canadian citizen residing in Canada and is a member of the Corporation.

When the Corporation receives recognition from appropriate governmental authorities in Mexico as the electric reliability organization, this provision will be expanded to provide for adequate representation of Mexican interests on the Member Representatives Committee.

Section 5 — Officers of the Member Representatives Committee — At the initial meeting of the Member Representatives Committee, and annually thereafter prior to the annual election of representatives to the Member Representatives Committee, the Member Representatives Committee shall select a chairman and vice chairman from among its voting members by majority vote of the members of the Member Representatives Committee to serve as chairman and vice chairman of the Member Representatives Committee during the upcoming year; provided, that the incumbent chairman and vice chairman shall not vote or otherwise participate in the selection of the incoming chairman and vice-chairman. The newly selected chairman and vice chairman shall not have been representatives of the same sector. Selection of the chairman and vice chairman shall not be subject to approval of the board. The chairman and vice chairman, upon assuming such positions, shall cease to act as representatives of the sectors that elected them as representatives to the Member Representatives Committee and shall thereafter be responsible for acting in the best interests of the members as a whole.

Section 6 — Vacancies on the Member Representatives Committee — In the event that any member of the Member Representatives Committee ceases to serve as a member of the Member Representatives Committee as a result of his or her death, resignation, retirement, disqualification, or removal or other cause, the members in the sector of which such member was a representative shall elect, as soon thereafter as reasonably possible, and in accordance with the procedures in Sections 3 and 4 of this Article VIII, a new member to replace the member of the Member Representatives Committee who ceases to serve. Except with regard to the selection of the chairman and vice chairman at the initial meeting of the Member Representatives Committee, the vacancies in the sector representatives created by the

selection of the chair and vice chair pursuant to Section 5 of this Article VIII shall be filled at the annual election of representatives to the Member Representatives Committee that is next held following the election of the chairman and vice chairman. In the case of the selection of the chairman and vice chairman at the initial meeting of the Member Representatives Committee, the sector representative vacancies created thereby shall be filled as soon thereafter as reasonably possible in accordance with the procedures in Section 3 of this Article VIII for sector representative vacancies.

Section 7 — Annual Meeting of the Member Representatives Committee — An annual meeting of the Member Representatives Committee for the election of independent trustees and to conduct such other business as may come before the meeting shall be held on or about February 1 of each year or as soon thereafter as is reasonably possible. By resolution adopted at any meeting of the Member Representatives Committee, the Member Representatives Committee may provide for additional regular meetings that may be held without further notice to the members of the Member Representatives Committee.

Section 8 — Special Meetings of the Member Representatives Committee — Special meetings of the Member Representatives Committee for any purpose or purposes may be called by the chair of the Member Representatives Committee or by any five (5) members of the Member Representatives Committee, which number shall include representatives from at least three sectors, and require notice given to all members of the Member Representatives Committee not less than seven (7) days prior to the date of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, telegraph, or other electronic media, or by express delivery.

Section 9 — Quorums and Voting for Meetings of the Member Representatives Committee — The quorum necessary for the transaction of business at meetings of the Member Representatives Committee shall be two-thirds of the voting members of the Member Representatives Committee attending the meeting in person or by proxy. A member of the Member Representatives Committee may give a proxy only to a person who is a member, or an officer, executive-level employee, agent or representative of a member, registered in the same sector. Each voting member of the Member Representatives Committee shall have one (1) vote on any matter coming before the Member Representatives Committee that requires a vote. Except as otherwise expressly provided in the Corporation's Certificate of Incorporation, these Bylaws or applicable law, actions by members of the Member Representatives Committee shall be approved upon receipt of the affirmative vote of a majority of the voting members of the Member Representatives Committee present and voting, in person or by proxy, at any meeting at which a quorum is present.

Section 10 — Meetings of the Member Representatives Committee to be Open — Notice to the public of the dates, places, and times of meetings of the Member Representatives Committee, and all nonconfidential material provided to the Member Representatives Committee, shall be posted on the Corporation's Web site, and notice of meetings of the Member Representatives Committee shall be sent electronically to all members of the Corporation, within 24 hours of the time that notice or such material is given to the Member Representatives Committee. Meetings of the Member Representatives Committee shall be open to the public, subject to reasonable limitations due to the availability and size of meeting

facilities; provided, that the Member Representatives Committee may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance and enforcement matters, litigation, or commercially sensitive or critical infrastructure information of any entity. Any or all members of, and any other participants in, the Member Representatives Committee may participate in a meeting of the Member Representatives Committee by a means of a communications system by which all persons participating in the meeting are able to hear each other.

Section 11 — Waivers of Notice of Meetings of the Member Representatives Committee; and Meeting Adjournments — Notice of a meeting of the Member Representatives Committee need not be given to any member of the Member Representatives Committee who signs a waiver of notice, in person or by proxy, whether before or after the meeting, or who attends the meeting without protesting, prior to the conclusion of the meeting, the lack of notice of such meeting. Notice of an adjourned meeting of the Member Representatives Committee need not be given if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if the period of adjournment does not exceed ten (10) days.

Section 12 — Action Without a Meeting of the Member Representatives Committee — Any action required or permitted to be taken at a meeting of the Member Representatives Committee may be taken by the Member Representatives Committee without a meeting if the action is consented to in writing by the number of members of the Member Representatives Committee entitled to vote on the action that would be required to approve the action at a meeting of the Member Representatives Committee with all of its members present. The call for action without a meeting of the Member Representatives Committee may be initiated by the Chair of the Member Representatives Committee or by any five (5) members of the Member Representatives Committee, which number shall include representatives from at least three (3) sectors. Notice of the proposed call for action without a meeting, and all nonconfidential material provided to the Member Representatives Committee in connection with the call for action without a meeting, shall be posted on the Corporation's Web site within 24 hours of the time notice of the call for action without a meeting or such material is provided to the members of the Members Representative Committee. The members of the Member Representatives Committee shall receive written notice of the results, and the results shall be posted on the Corporation's Web site, within seven (7) days of the action vote, and all written responses of voting members of the Member Representatives Committee shall be filed with the minutes of the Corporation.

Section 13 — Other Procedures of the Member Representatives Committee — The chairman of the board in office on November 1, 2006, shall preside at the initial meeting of the Member Representatives Committee, until a chairman is selected in accordance with Section 5 of this Article VIII. Except as to any matter as to which the procedure to be followed by the Member Representatives Committee is expressly set forth in these Bylaws, the Member Representatives Committee may adopt such additional procedures, not inconsistent with these Bylaws, as it deems appropriate.

ARTICLE IX
Reliability Standards

Section 1 — Development of Reliability Standards — The Corporation shall develop, implement and, in all regions in which necessary governmental approvals have been obtained or authority has been provided, enforce, reliability standards that provide for reliable operation of the bulk power systems of North America. All reliability standards shall be approved by the board. All reliability standards of the Corporation shall be posted on its Web site. Nothing in this Article shall be deemed to invalidate any standard of the Corporation that was in effect on November 1, 2006.

Section 2 — Procedures for Development of Reliability Standards —The Corporation shall develop reliability standards pursuant to procedures and processes that shall be specified in the Rules of Procedure of the Corporation. The Rules of Procedure shall provide for the development of reliability standards through an open, transparent, and public process that provides for reasonable notice and opportunity for public comment, due process, and balancing of interests and is designed to result in reliability standards that are technically sound. Participation in the process for development of 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 bulk power system.

Section 3 — Procedures for Determinations of Violations of Reliability Standards and Imposition of Sanctions for Violations — In all regions in which regulatory approval has been obtained or governmental authority has been provided, the Corporation shall consider and make determinations that an owner, operator, or user of the bulk power system has violated a reliability standard, and shall impose sanctions for such violations, pursuant to procedures and processes that shall be specified in the Rules of Procedure of the Corporation. Such procedures and processes shall provide for reasonable notice and opportunity for hearing. Any sanction imposed for a violation of a reliability standard shall bear a reasonable relation to the seriousness of the violation and shall take into consideration efforts of the owner, operator, or user of the bulk power system to remedy the violation in a timely manner. Subject to any necessary action by any applicable governmental authorities, no sanction imposed for a violation of a reliability standard shall take effect until the thirty-first (31) day after the Corporation, where authorized by law or agreement, files with the Commission or other applicable governmental authority notice of the sanction and the record of the proceedings in which the violation and sanction were determined, or such other date as ordered by the Commission or other applicable governmental authority or as prescribed by applicable law.

ARTICLE X
Agreements with Regional Entities

Section 1 — Delegation Agreements with Regional Entities — The Corporation may, in accordance with appropriate governmental authority, enter into agreements with regional entities pursuant to which a regional entity shall be delegated the authority of the Corporation to enforce reliability standards within a geographic region of North America and may

develop and propose reliability standards to be in effect within such region. All delegation agreements with regional entities shall be approved by the board. No delegation agreement with a regional entity shall be effective with respect to a region until the agreement has received any necessary approval from an applicable governmental authority.

Section 2 — Standards for Delegation Agreements — The Corporation shall be permitted to enter into a delegation agreement with a regional entity only if the board determines that (i) the regional entity has agreed to promote, support, and comply with the purposes and policies of the Corporation as set forth in its Certificate of Incorporation, Bylaws, Rules of Procedure, and Reliability Standards as from time to time adopted, approved, or amended; (ii) the regional entity satisfies the criteria set forth in Sections 39.3(b) and 39.8 of the Commission's regulations, or other criteria specified by applicable governmental authorities, and (iii) the delegation agreement will promote effective and efficient administration of the reliability of the bulk power system.

ARTICLE XI
Rules of Procedure

Section 1 — Development of Rules of Procedure — The Corporation shall develop and implement such Rules of Procedure as in the judgment of the board are necessary or appropriate to carry out the purposes of the Corporation and to govern its operations, including without limiting the foregoing, Rules of Procedure relating to (i) registration of owners, operators, and users of the bulk power system; (ii) development of reliability standards; (iii) procedures for standing committees of the Corporation, subgroups of standing committees, and other committees, subcommittees, task forces, and sector-specific forums of the Corporation; (iv) critical infrastructure protection; (v) conduct of readiness evaluations and reliability assessments; (vi) enforcement of compliance with reliability standards and determinations of violations of reliability standards by owners, operators, and users of the bulk power system; (vii) impositions of sanctions for violations of reliability standards; (viii) development, implementation, and administration of delegation agreements with regional entities; (ix) personnel certification; (x) event analysis and information exchange; (xi) realtime monitoring of the bulk power system; and (xii) development and administration of budgets, business plans, and funding mechanisms of the Corporation. All Rules of Procedure of the Corporation shall be posted on its Web site.

Section 2 — Adoption, Amendment, and Repeal of Rules of Procedure — Except as provided in Section 2 of Article XII, all Rules of Procedure, amendments thereto and repeals thereof shall be approved by the board. Proposals to adopt new Rules of Procedure or to amend or repeal existing Rules of Procedure may be submitted by (i) the Member Representatives Committee, (ii) any fifty (50) members of the Corporation, which number shall include members in at least three sectors, (iii) a committee of the Corporation to whose purpose and functions the Rule of Procedure pertains, or (iv) an officer of the Corporation. Unless the board determines that exigent conditions exist requiring adoption of a new Rule of Procedure or amendment or repeal of an existing Rule of Procedure in a shorter time, all proposals for adoption, amendment and repeal of Rules of Procedure shall be posted on the Corporation's Web site and subject to public comment for a minimum of forty-five (45) days

prior to action by the board. All Rules of Procedure and amendments to and repeals of Rules of Procedure approved by the board shall be submitted to the Commission and to other applicable governmental authorities for approval, and shall not be effective in the United States until approved by the Commission or in Canada or Mexico until approval is obtained from any governmental authority from which approval is required in those countries and subject to any conditions, limitations, or modifications required by the Commission or other governmental authority. Nothing in this Article shall be deemed to invalidate any Rule of Procedure of the Corporation that was in effect on November 1, 2006.

ARTICLE XII
Personnel Certification Governance Committee

Section 1 — Personnel Certification Governance Committee — There shall be a Personnel Certification Governance Committee of the Corporation, which shall be a standing committee of the Corporation. The purpose of the Personnel Certification Governance Committee shall be to provide oversight to the policies and processes used to implement and maintain the integrity and independence of the Corporation's System Operator Certification Program. The governance authority and structure of the Personnel Certification Governance Committee shall be implemented and maintained so that policies and procedures are established to protect against undue influence that could compromise the integrity of the System Operator Certification process.

Section 2 — Appointment and Reporting of the Personnel Certification Governance Committee — The members of the Personnel Certification Governance Committee shall be appointed by the board from candidates selected and presented by a nominating task force in accordance with Rules of Procedure for the Personnel Certification Governance Committee. Nominations and appointments shall take into account the need to include representatives of all geographic regions of North America on the Personnel Certification Governance Committee. The Personnel Certification Governance Committee shall report directly to the board and the president of the Corporation regarding governance and administration of the System Operator Certification Program; provided, however, that the Personnel Certification Governance Committee shall have autonomy in developing and implementing system operator certification eligibility requirements, the development, administration, and scoring of the system operator assessment instruments, and operational processes for the System Operator Certification Program. The Personnel Certification Governance Committee shall provide to the board periodic assessments, no less frequently than every two (2) years, of the effectiveness of the System Operator Certification Program.

Section 3 — Administration of the Personnel Certification Governance Committee — In order to maintain the independence of the Personnel Certification Governance Committee, staff of the Corporation shall administer the System Operator Certification program on behalf of the Personnel Certification Governance Committee on a fee for service basis.

ARTICLE XIII
Budgets and Funding

Section 1 — Compensation of the Board and Member Representatives Committee — The board shall have the right to fix from time to time, by resolution adopted by a majority of the independent trustees then serving as trustees, the amount of the annual retainer fee or other compensation to be paid to the independent trustees for their services to the Corporation, including any fees to be paid for each meeting of the board or any board committee attended by an independent trustee. No compensation shall be paid to the management trustee for his or her services on the board, other than the compensation paid to the management trustee for services as president of the Corporation. No compensation shall be paid by the Corporation to the members of the Member Representatives Committee for their services on the Member Representatives Committee.

Section 2 — Preparation and Adoption of Annual Budget, Business Plan, and Funding Mechanism — The board shall prepare or cause to be prepared an annual budget for the administrative and other expenses of the Corporation, including the expenditures for the fiscal year for any material special projects undertaken by the Corporation and reasonable and proper reserves and provisions for contingencies, an accompanying business plan for the Corporation, and a funding mechanism, for each fiscal year. The annual budget, business plan, and funding mechanism of the Corporation shall be for a fiscal year commencing on January 1 and ending on December 31. Each annual budget, business plan, and funding mechanism (including the annual budget, annual business plan, and annual funding mechanism for each regional entity) shall be approved by the board at a regular meeting or a special meeting of the board duly called for that purpose. The board shall approve each annual budget, business plan, and funding mechanism at least 135 days before the start of the fiscal year in order to allow for timely submittal of the approved annual budget, business plan, and funding mechanism to the applicable governmental authorities.

Section 3 — Criteria for Funding Mechanisms — The annual funding mechanism shall be designed to recover, over the course of the fiscal year, the sum of (i) the annual budget, (ii) less revenues projected to be received by the Corporation from other sources such as sales of services and materials and registration, application and certification fees for programs conducted or administered by the Corporation, and (iii) plus or minus the estimated deficiency or excess of the Corporation's revenues compared to its expenditures for the current fiscal year. The annual funding mechanism shall consist of such assessments as determined by the 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.

Section 4 — Consultation in Preparation of Annual Budget, Business Plan, and Funding Mechanism — In preparing the annual budget, business plan, and funding mechanism, the board shall consult with the members of the Member Representatives Committee, and shall post a draft budget and business plan for review and comment by the members of the Corporation and the Member Representatives Committee and the standing committees of the Corporation for at least thirty (30) days prior to the date of the meeting of the board at which the annual budget, business plan, and funding mechanism are to be adopted.

Section 5 — Modified or Supplemental Funding Mechanisms — During the course of a fiscal year, the board may modify the approved funding mechanism or develop and approve a supplemental funding mechanism if determined by the board to be necessary due to such factors as a shortfall in revenues of the Corporation from projected levels, incurred or anticipated expenditures or new projects not provided for in the annual budget, or such other factors as in the judgment of the board warrant modification of the funding mechanism for the fiscal year or development of a supplemental funding mechanism. In preparing a modified or supplemental funding mechanism, the board shall follow the provisions of Section 4 of this

Article XIII to the extent possible in the judgment of the board in light of the exigency of the circumstances necessitating preparation and approval of the modified or supplemental funding mechanism. Each modified or supplemental funding mechanism shall be approved by the board at a regular meeting or a special meeting of the board duly called for that purpose.

Section 6 — Submission of Annual Budgets, Business Plans, and Funding Mechanisms to the Governmental Authorities — Each annual budget, annual business plan, and annual, modified, or supplemental funding mechanism approved by the board (including the annual budget, annual business plan, and annual, modified, or supplemental funding mechanism for each regional entity) shall be submitted by the Corporation to the applicable governmental authorities for approval in accordance with its regulations, except as otherwise provided by applicable law or by agreement, and shall not be effective until it has received any necessary approval by the applicable governmental authorities. If a governmental authority by order modifies or remands an annual budget, business plan, or annual, modified, or supplemental funding mechanism, the board shall promptly following such order adopt such modifications to the budget, business plan, or funding mechanism as are required or directed by the order of the governmental authority.

ARTICLE XIV
Amendments to the Bylaws

Section 1 — Amendments to the Bylaws — These Bylaws may be altered, amended, or repealed by a majority vote of both the board and the Member Representatives Committee at respective meetings of the board and the Members Representative Committee at which a quorum is present. Written notice of the subject matter of the proposed changes to the Bylaws shall be provided, as appropriate, to the trustees or to the Member Representatives Committee not less than ten (10) nor more than sixty (60) days prior to the date of the meeting of the board or of the Member Representatives Committee at which the vote is to be taken. Notwithstanding the provisions of this Article XIV, the members of the Corporation voting by sector shall have the right to alter, amend, or repeal Bylaws adopted by the board and the Member Representatives Committee and to adopt new Bylaws, provided that any such alteration, amendment, or repeal or the adoption of new Bylaws is approved by vote of two-thirds of the sectors at a meeting of Members called for that purpose, or by written consent of two-thirds of the sectors, where the number of votes for and against the proposed alteration, amendment, repeal, or adoption of Bylaws shall be determined in accordance with Section 2 of Article IV. Any alteration, amendment, repeal, or adoption of Bylaws shall be subject to

any applicable requirements for filing with or approval by the Commission and any other applicable governmental authority.

ARTICLE XV
General

Section 1 — Indemnification — The Corporation shall indemnify its officers, trustees and other corporate agents to the full extent from time to time permitted by the New Jersey Nonprofit Corporation Act and other applicable law. Such right of indemnification shall inure to the benefit of the legal representative of any such person. The foregoing indemnification shall be in addition to, and not in restriction or limitation of, any privilege or power that the Corporation may have with respect to the indemnification or reimbursement of its trustees, officers, or other corporate agents. The Corporation shall also pay or advance expenses incurred by an officer, trustee, or other corporate agent in connection with a proceeding in advance of the final disposition of the proceeding upon receipt of an undertaking by or on behalf of the officer, trustee, or other corporate agent to repay the amount unless it shall be ultimately determined that the officer, trustee, or other corporate agent is entitled to be indemnified by the Corporation.

Section 2 — Parliamentary Rules — In the absence of and to the extent not inconsistent with specific provisions in these Bylaws, meetings or other actions pursuant to these Bylaws shall be governed by procedures that the board may, from time to time, establish by resolution.

Section 3 — Dissolution — Upon dissolution of the Corporation, in accordance with paragraph TENTH of the Certificate of Incorporation, the remaining assets of the Corporation after payment of debts shall be distributed in the manner determined by the board, provided, (i) that no part of the assets shall be distributed to any trustee of the Corporation, and (ii) that the distribution of assets shall be consistent with the requirements of Section 501(c)(6) of the United States Internal Revenue Code of 1986, as amended.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

June 4, 2018

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Petition of the North American Electric Reliability Corporation for Approval of Amendments to the Midwest Reliability Organization Bylaws
Docket No. RR18-_-000

Dear Secretary Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits for approval the "*Petition of the North American Electric Reliability Corporation for Approval of Amendments to the Midwest Reliability Organization Bylaws*." On May 4, 2018, the Federal Energy Regulatory Commission issued an order approving changes to the Delegation Agreement between NERC and the Midwest Reliability Organization ("MRO") that expanded the MRO footprint resulting from the termination of the Regional Delegation Agreement between Southwest Power Pool, Inc. and NERC.[1] As explained in further detail in the Petition, the proposed amendments to the MRO Bylaws are as follows: (1) an addition of two Regional Directors positions reflecting the geography of the MRO's expanded footprint on its Board of Directors; (2) an increase to the number of independent director positions on its Board of Directors; and (3) a proposal of ministerial changes to other sections of the MRO Bylaws. There are no reliability-related issues raised by the amendments and as amended, the MRO Bylaws continue to satisfy the five governance criteria specified in Exhibit B to the Amended and Restated Delegation Agreement between MRO and NERC. The proposed amendments to the MRO Bylaws have been approved by the MRO Board of Directors, the MRO Members, and the NERC Board of Trustees.

This filing consists of: (1) this transmittal letter; (2) the narrative text of the Petition that follows this transmittal letter; and (3) Attachments 1 and 2 to the Petition that contain clean and redline versions of the proposed amendments to MRO Bylaws, respectively. All documents are transmitted in a single PDF file.

Please contact the undersigned if you have any questions concerning this filing.

[1] *Joint Petition of North American Electric Reliability Corporation, Midwest Reliability Organization, and SERC Reliability Corporation for Approvals in Connection with the Dissolution of the Southwest Power Pool Regional Entity*, Docket No. RR18-3-000 (Mar. 5, 2018).

Respectfully submitted,

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR18-_-000**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF AMENDMENTS TO MIDWEST RELIABILITY ORGANIZATION BYLAWS

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June 4, 2018

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ATTACHMENTS

ATTACHMENT 1: Amended Midwest Reliability Organization Bylaws – Clean

ATTACHMENT 2: Amended Midwest Reliability Organization Bylaws – Redline

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR18-_-000**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF AMENDMENTS TO THE MIDWEST RELIABILITY ORGANIZATION BYLAWS

Pursuant to § 215(e)(4) of the Federal Power Act ("FPA")[1] and 18 C.F.R. § 39.10[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC") hereby requests Commission approval of the proposed amendments to the Midwest Reliability Organization ("MRO") Bylaws.[3] The proposed revisions are intended to (1) reflect the geographic representation of MRO's expanded footprint on its Board of Directors, resulting from the termination of the Regional Delegation Agreement between Southwest Power Pool, Inc. ("SPP RE") and NERC as well as the transfer of 109 registered entities from SPP RE's footprint to MRO's footprint effective July 1, 2018 and, (2) increase the number of independent directors on the MRO Board of Directors. As described in greater detail in Section I of this petition, MRO proposes to amend the following sections of its Bylaws: new Section 1.22 (defining "Regional Director"), revised Section 7.3 ("Composition of the Board of Directors"), revised Section 7.4 ("Term of Directors"), revised Section 7.5

[1] 16 U.S.C. § 824o (2006).
[2] 18 C.F.R. § 39.5 (2018).
[3] Pursuant to the Commission's November 2, 2015 and March 23, 2016 orders in Docket No. RR15-12, Regional Entity bylaws and standard development procedures are no longer maintained as exhibits to the Regional Delegation Agreements. NERC maintains an up-to-date copy of each Regional Entity's bylaws and standard development procedure on its website at: http://www.nerc.com/AboutNERC/Pages/Regional-Entity-Delegation-Agreements.aspx.

("Compensation and Reimbursement"), revised Section 7.6 ("Vacancies"), and ministerial changes to various sections of the MRO Bylaws.

NERC staff has determined that, as revised, the MRO Bylaws continue to satisfy the five governance criteria in Exhibit B to the Amended and Restated Delegation Agreement, and that there are no reliability-related issues raised by the proposed amendments. Accordingly, the NERC Board of Trustees approved the proposed amendments to the MRO Bylaws at its May 10, 2018 meeting.

Attachments 1 and **2** attached hereto to this petition consist of clean and redlined versions, of the revised MRO Bylaws.

I. PROPOSED AMENDMENTS TO THE MRO BYLAWS

A. New Section 1.22 – Defining a "Regional Director"

The first proposed amendment to the MRO Bylaws introduce a new defined term "Regional Director", a new type of directorship on the MRO Board of Directors, which contrasts with an "Independent Director." The newly proposed "Regional Director" is defined as an employee of a MRO Member who meets the minimum representation requirements for the seven industry sectors in Section 1.14 (Industry Sectors) of the MRO Bylaws. MRO currently has a hybrid Board with 17 Industry Sector Directors and two Independent Directors. Stakeholder representation is determined by achieving a certain balance of industry sectors, regardless of geographic location. The creation of a Regional directorship allows the MRO Board of Directors to nominate individuals from different parts of the regional footprint to meet the existing bylaw preference of "ensuring geographical representation of the Corporate Region on the Board."[4] MRO proposes adding four new Board seats – two of which will be held by Regional Directors. The initial focus

[4] MRO Bylaws Section 7.3.

for the addition of two proposed Regional Director seats will be on seeking representatives from registered entities transferring their registration from SPP RE to MRO.

B. Section 7.3 – Composition of the Board of Directors

As previously stated, MRO currently has a hybrid Board with 17 Industry Sector Directors and two Independent Directors. MRO proposes to increase the total number of directors on the Board from 19 to 23 – representing the two new proposed Regional Directors and two additional proposed Independent Directors. Like the existing Independent Directors, the two new proposed Regional Directors shall be nominated by the MRO Board from one or two industry sectors in Section 1.14 (Industry Sectors) and elected by all Members. MRO continues to add to the independence of its Board by having half of the new proposed director positions be Independent Directors.

C. Section 7.4 – Term of Directors

MRO proposes to define the term limits for both Regional and Independent Director positions as three years. All terms are proposed to end on December 31 of a given year. MRO also clarifies in its Bylaws that the initial term for the four new proposed directors may be shorter than three years if the term begins after January 1 of a given year.

With the introduction of a "Regional Director," MRO defines the removal requirements as "any time by the affirmative vote of two-thirds (2/3) of the Members." This contrasts with the removal requirements for an Independent Director which are "by the affirmative vote of two-thirds (2/3) of the remaining directors.

D. Section 7.5 – Compensation and Retirement

MRO clarifies that no Regional Director shall receive compensation due to his or her employment by an MRO member.

E. Section 7.6 – Vacancies

MRO proposes that when a successor director takes over a term created by a vacancy, he or she will only hold the position for the period during which the vacancy exists.

II. MRO AND NERC APPROVALS OF THE PROPOSED AMENDMENTS

The proposed amendments were approved by the MRO Board of Directors on February 27, 2018 and by its Members on March 21, 2018. The NERC Board of Trustees approved the proposed amendments at its May 10, 2018 meeting.

III. CONCLUSION

NERC respectfully requests that the Commission approves the proposed amendments to the MRO Bylaws, as shown in **Attachment 2** to this Petition.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston

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Counsel for the North American Electric Reliability Corporation

Dated: June 4, 2018

ATTACHMENT 1

Amended Bylaws –to the Amended and Restated Delegation Agreement Between

North American Electric Reliability Corporation

and

Midwest Reliability Organization – **Clean**

BYLAWS OF THE

MIDWEST RELIABILITY ORGANIZATION, INC.

As amended through xxx xx, 2018

Approved by the MRO Board of Directors on February 27, 2018; the MRO Members on March 21, 2018; the North American Electric Reliability Corporation Board of Trustees on May 10, 2018

Approved by FERC Effective [proposed date]

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BYLAWS
OF THE
MIDWEST RELIABILITY ORGANIZATION, INC.
a Delaware nonprofit corporation
(the "Corporation")

ARTICLE 1
DEFINITIONS

Section 1.1 **Adjunct Member.** "Adjunct Member" means an entity that: (1) is not eligible to belong to an Industry Sector; (2) has a material interest in reliability issues in the Corporation's Region and (3) becomes an Adjunct Member of the Corporation.

Section 1.2 **Affiliate.** "Affiliate" means with respect to any entity, any other entity that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such entity, as determined in the sole discretion of the board of directors of the Corporation. For this purpose, "control" may be presumed by the direct or indirect ownership of 50 percent or more of the outstanding voting capital stock or other equity interests having ordinary voting power. A member of, or owner of an interest in, a transmission company that FERC has found meets the independence requirements for a regional transmission organization shall not be deemed to be an affiliate of such transmission company.

Section 1.3 **Bulk Power System.** "Bulk Power System" means (1) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (2) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in local distribution of electric energy. The term Bulk Power System shall be interpreted consistently with any definition given by NERC.

Section 1.4 **Bulk Power System Users.** "Bulk Power System Users" means any entity that sells, purchases, or transmits electric power over the Bulk Power System, or that owns, operates or maintains facilities or control systems that are part of the Bulk Power System.

Section 1.5 **Canadian Utility.** "Canadian Utility" means an entity that is a government-owned utility serving in Canada within the Corporate Region.

Section 1.6 **Corporation.** "Corporation" means Midwest Reliability Organization, Inc.

Section 1.7 **Cooperative.** "Cooperative" means an entity serving within the Corporate Region that generally has the following characteristics: (1) private independent electric utility; (2) incorporated under the laws of a state in which they operate; (3) established to provide electric service to its members; (4) owned by the consumers they serve; and (5) governed by a board of directors elected from the membership. This sector includes Generation and Transmission Cooperatives and Public Utility Districts.

Section 1.8 **Corporate Region.** "Corporate Region" means the geographic area boundaries of the Bulk Power Systems as designated by the then current delegation agreement.

Section 1.9 **FERC.** "FERC" means the Federal Energy Regulatory Commission.

Section 1.10 **Federal Power Marketing Agency.** "Federal Power Marketing Agency means an agency of the federal government created to market power within the Corporate Region.

Section 1.11 **Generator and Power Marketer.** "Generator and Power Marketer" means an entity that owns or operates more than 50 MW of generation in the Corporate Region, or is a power marketer doing business in the Corporate Region, and that does not qualify also to participate in the Investor Owned Utility, Cooperative, Municipal Utility, Federal Power Marketing Agency or Canadian Utility Sectors.

Section 1.12 **Good Utility Practice.** "Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts, which in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the Corporate Region.

Section 1.13 **Independent Director.** "Independent Director" means an individual who is not (1) an officer or employee of the Corporation; (2) a member, director, officer or employee of a Member or Adjunct Member of the Corporation; (3) a director, officer or employee of any registered entity on the NERC registry; or (4) reasonably perceived as having a direct financial interest in the outcome of a decision by the board of directors and who (a) does not have any other relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a director and (b) meets any additional requirements of independence established by the board of directors.

Section 1.14 **Industry Sector(s).** "Industry Sector or Sector(s)" means a group of Bulk Power System Users in the Corporate Region with substantially similar reliability interests, as determined by these Bylaws. The Industry Sectors shall include the following: (1) Transmission System Operators; (2) Generators and Power Marketers; (3) Investor Owned Utilities (4) Cooperatives; (5) Municipal Utilities (6) Federal Power Marketing Agencies; and (7) Canadian Utilities.

Section 1.15 **Investor Owned Utility.** "Investor Owned Utility" means a for-profit entity that owns and operates a distribution system and serves end-use load within the Corporate Region pursuant to an obligation to serve under state, federal or provincial law, including a default service obligation, or pursuant to a tariff by which the entity offers service to the general public.

Section 1.16 **Member.** "Member" means any entity eligible to belong to an Industry Sector(s) that becomes a Member of the Corporation.

Section 1.17 **Membership.** "Membership" includes Adjunct Members and Members of the Corporation. Membership in the Corporation is voluntary and does not affect NERC registration.

Section 1.18 Municipal Utility. "Municipal Utility" means an entity that is an electric utility that is owned by a state or municipality, or group of municipalities, including a joint action agency, which serves within the Corporate Region.

Section 1.19 NERC. "NERC" means the North American Electric Reliability Corporation or a successor entity.

Section 1.20 Person. "Person" means any natural person, corporation, cooperative, partnership, association, or other private or public entity.

Section 1.21 Public Utility District. "Public Utility District" means an entity that is a state political or governmental subdivision that owns electric generation, transmission and distribution facilities and that was created and organized under state statutes that are different than those that Municipal Utilities in the same state are created and organized under.

Section 1.22 Regional Director. "Regional Director" means a director who is an employee of a Member and meets the qualifications set out in these Bylaws for directors elected from an Industry Sector.

Section 1.23 Regional Entity. "Regional Entity" means an entity having authority pursuant to a delegation agreement with NERC and pursuant to any agreements or laws relating to the Corporation's functions in Canada.

Section 1.24 Regulatory Participant. "Regulatory Participant" means any state or provincial regulatory agencies in the Corporate Region exercising authority over the rates, terms or conditions of electric service of an entity other than itself within the Corporate Region, or the planning, siting, construction or operation of electric facilities of an entity other than itself within the Corporate Region, as well as any representatives of FERC, regional advisory bodies that may be established by FERC, or representatives of any federal regulator or agency.

Section 1.25 Reliability Standard. "Reliability Standard" means a NERC Reliability Standard, duly in effect, under the rules, regulations and laws governing such standards, to provide for reliable operation of the Bulk Power System.

Section 1.26 Transmission System Operator. "Transmission System Operator" means an entity that operates or controls operation of high voltage transmission facilities within the Corporate Region (more than 300 miles of transmission at 100 kV or greater) that does not also own, operate or control generation within the Corporate Region, except to the limited extent permitted by FERC for independent transmission organizations with respect to ancillary service obligations. Transmission System Operators include: (1) regional transmission organizations; (2) independent transmission providers; (3) independent system operators; (4) and transmission-only companies.

ARTICLE 2
PURPOSE

Section 2.1 **Purpose.** The Corporation will be a Regional Entity within the NERC structure for the purpose of preserving and enhancing electric service reliability, adequacy and security in the Corporate Region and other interconnected regions for the benefit of all end-users of electricity in the Corporate Region.

Section 2.2 **Activities.** In support and furtherance of its purpose, the Corporation's responsibilities shall include, but not be limited to: (1) proposing Reliability Standards, including regional variances or regional Reliability Standards required to maintain and enhance electric service reliability, adequacy and security in the Corporate Region; (2) assessing compliance with and enforcing Reliability Standards, to the extent authorized by applicable agreements and/or law governing a Member's membership in the Corporation; (3) conducting investigations and data analysis on disturbances, system events, and related matters; (4) conducting long-term assessments of reliability within the Corporate Region; and (5) other related activities.

Section 2.3 **Not-for-Profit Corporation.** The Corporation is operated as a Delaware non-stock, nonprofit corporation and is organized pursuant to the general corporation law of the State of Delaware. The Corporation shall be exempt from federal income taxation pursuant to Section 501(c) of the Internal Revenue Code of 1986, as amended (hereinafter the "Code"). The Corporation shall not engage directly or indirectly in any activity that would invalidate its status as an organization exempt from taxation under Section 501(a) of the Code as an organization described in Section 501(c)(3) of the Code. No part of the net income to the Corporation shall inure to the benefit of or be distributed to its directors, officers, members or other private persons, except that the Corporation shall be authorized and empowered to pay reasonable compensation for services actually rendered.

ARTICLE 3
POWERS

Section 3.1 **Powers.** The Corporation shall have the power to engage in any lawful act or activity for which corporations may be organized under the general corporation law of the State of Delaware, subject to any limitations provided in applicable federal, provincial or state law or in the Corporation's certificate of incorporation or these Bylaws.

ARTICLE 4
OFFICES

Section 4.1 **Offices.** The principal office of the Corporation shall be located initially within the Corporate Region, at such location as the board of directors may from time to time determine, giving consideration to the total cost to the Corporation and convenience of travel for staff, Members and Regulatory Participants. Once established, the principal office may remain in its location, even if outside the Corporate Region.

ARTICLE 5
MEMBERS

Section 5.1 Classes of Members. The Corporation shall have two classes of members; Adjunct Members and Members.

Section 5.2 Affiliates. Each Affiliate of a Member or Adjunct Member may separately be a Member or Adjunct Member, respectively.

Section 5.3 Admission of Members and Adjunct Members. New Members and Adjunct Members may join the Corporation upon submittal of an application, in a form approved by the president, and payment of the fees as established by the Corporation. An entity applying to be a Member shall designate the Industry Sector to which it belongs. A Member may change its Industry Sector designation once each calendar year, by providing notice to the president at least sixty (60) days prior to the beginning of such year. The president shall review a membership application and may request demonstration by the applicant that it qualifies for membership in a particular Industry Sector or as an Adjunct Member. Any dispute with respect to a Member's or Adjunct Member's qualifications shall be resolved by the board of directors. The president shall have authority to approve an application for membership, subject to review by the board of directors.

Section 5.4 Voting Rights. Each Member in good standing shall be entitled to one vote in the Industry Sector in which it is a Member, on matters submitted to a vote of Members. A Member delinquent in payment of its dues, fees or other obligations to the Corporation shall not be entitled to a vote.

Section 5.5 Transfer of Membership. Membership or a right arising from such membership may not be transferred except to any Person succeeding to all or substantially all of the assets of the Member or Adjunct Member. The president shall have authority to approve any such transfer, subject to review by the board of directors.

Section 5.6 Obligations of Members and Adjunct Members. By applying for Membership the applicant acknowledges that it is authorized and agrees to comply with, Reliability Standards to the extent such standards are applicable, and other obligations as set forth in these Bylaws or duly adopted by the board of directors in order to achieve the purposes of the Corporation. Such obligations include but are not limited to requirements to provide data and information needed to perform the functions of the Corporation and the payment of dues and any authorized penalties, including penalties and other obligations resulting from violations of Reliability Standards assessed in accordance with NERC rules and subject to applicable regulatory approval.

Section 5.7 Withdrawal. Withdrawal from Membership in the Corporation is accomplished by providing written notice to the president of the Corporation of such intent to withdraw. Such notice shall specify a date, not earlier than thirty (30) days from the date of notice, on which the withdrawal shall become effective; provided however, that any such withdrawing Member or Adjunct Member shall remain liable to the Corporation for any fees, dues, sanctions or obligations to the Corporation incurred during the entity's Membership, as well as its share of

any obligations of the Corporation for the current fiscal year. If notice is given after October 1 of the current calendar year, the entity will also be liable for any fees and dues included in the budget for the following fiscal year. Section 5.7 does not apply to any fees, dues, or obligations associated with the Corporation responsibilities under delegated authority from NERC or applicable regulatory authorities.

Section 5.8 Budget and Fees. The board of directors shall propose to NERC a budget for delegated functions exercised by the Corporation pursuant to a delegation agreement with NERC and pursuant to any agreements or laws relating to the Corporation's functions in Canada. For those functions outside the scope of the Corporation's delegated functions, the board of directors may from time to time fix the amount of dues, assessments, or fees, if any, and determine the methods of collection, consistent with this Section, the regulations of applicable government authorities, and any resolutions duly adopted by the Members under Section 6.5.2 of these Bylaws.

ARTICLE 6
MEETING OF MEMBERS

Section 6.1 Annual Meeting of Members. The Members shall hold an annual meeting each calendar year in December, or at such other time specified by the board of directors, in order for Members to review the proposed budget and operations of the Corporation. Adjunct Members may attend the annual meeting of Members. The Membership shall be entitled to at least thirty (30) days prior written notice of the annual meeting. At or before the annual meeting of Members: (1) each Industry Sector shall elect the successor(s), if any, for any director(s) from its Industry Sector whose term will expire before the next annual meeting of the Members, provided however, that any Industry Sector may elect a successor director representing such Industry Sector prior to such annual meeting, in accordance with the provisions of this Article 6, in which case the election of such succeeding director(s) shall be reported to the Corporation at such annual meeting; (2) the Members will elect Independent Directors, if any; (3) the president and treasurer shall report on the activities and financial condition of the Corporation; and (4) the Members shall consider and act upon such other matters as may be raised, consistent with the notice of the annual meeting. The failure to hold an annual meeting in accordance with these Bylaws shall not affect the validity of a corporate action.

Section 6.2 Special Meetings of Members.

6.2.1. Who May Call. Special meetings of the Members may be called by six (6) members of the board of directors, by the president, or if at least 10 percent of the Members sign, date, and deliver to the president one or more written demands for a special meeting describing the purpose for which it is to be held. Adjunct Members may attend special meetings of the Members.

6.2.2. Notice of Meeting. Within fifteen (15) days after receipt of a demand for a special meeting from Members, the president shall cause a special meeting to be called and held on notice to the Membership no later than forty-five (45) days after receipt of the demand. If the president fails to cause a special meeting to be called and held as required by this section, a Member making the demand may call the meeting by giving notice under

Section 6.3. In either event, notice of the meeting and the costs of the meeting shall be at the expense of the Corporation.

6.2.3. Time and Place of Special Meetings. Special meetings of the Members shall be held at a location designated by the president or the board of directors. If a special meeting is demanded by the Members, the meeting must be held in a facility of appropriate size to accommodate the Membership and at a location within the Corporate Region.

6.2.4. Notice Requirements; Business Limited. The notice of a special meeting must contain a statement of the purposes of the meeting. The business transacted at a special meeting is limited to the purposes stated within the notice of the meeting. Business transacted at a special meeting that is not included in those stated purposes is voidable by, or on behalf of, the Corporation, unless 90 percent of the Members entitled to vote were present at such meeting or have waived notice of the meeting under Section 6.3.

Section 6.3 Notice Requirements.

6.3.1. To Whom Given. Notice of meetings of Members must be given to the Membership as of the record date determined under Section 6.4. If the meeting is an adjourned meeting and the date, time, and place of the meeting were announced at the time of the adjournment, notice is not required unless a new record date for the adjourned meeting is or must be fixed.

6.3.2. When Given; Contents. In all cases where a specific minimum notice period has not been fixed by law or these Bylaws, the notice must be given at least five (5) days before the date of a meeting and not more than sixty (60) days before the date of a meeting. The notice must contain the date, time and place of the meeting, and an agenda of the matters upon which action may be taken at the meeting. A matter may be added to the agenda of a meeting at the meeting upon the affirmative vote of three-quarters (3/4) of the Industry Sector votes cast on a motion to amend the agenda.

6.3.3. Waiver of Notice; Objections. A Member may waive notice of a meeting of Members. A waiver of notice by a Member entitled to notice is effective whether given before, at, or after the meeting, and whether given in writing, or by attendance. Attendance by a Member at a meeting is a waiver of notice of that meeting, unless the Member objects at the beginning of the meeting to the transaction of business because the meeting is not lawfully called or convened, or objects before a vote on an item of business because the item may not lawfully be considered at that meeting and does not participate in the consideration of the item at that meeting.

Section 6.4 Record Date; Determining Members Entitled to Notice and Vote. The board of directors may fix a date not more than forty (40) days before the date of a meeting of Members as the date for the determination of the Membership entitled to notice of the meeting and the Members entitled to vote at the meeting. When a date is so fixed, only the Membership on that date is entitled to notice and only the Members are entitled to vote at a meeting of the Members unless the board of directors fixes a new date for determining the right to notice and to vote, which

it must do if the meeting is adjourned to a date more than sixty (60) days after the record date for determining Membership entitled to notice of the original meeting.

Section 6.5 Right to Vote; Act of Members. Voting of the Members shall be by Industry Sector, with each Industry Sector entitled to the same number of votes as it has directors on the board. If a quorum is present, except with respect to amendments of these Bylaws, modification of a budget approved by the board of directors or termination of the Corporation, the affirmative vote of the majority of the Industry Sector votes present and entitled to vote, which must also be a majority of the required quorum, is the act of the Members, however, in no event will an action of the Members be valid where the action was passed solely by the vote of Members from two Industry Sectors or defeated solely by the vote of Members in a single Industry Sector. Within an Industry Sector, each Member within the Industry Sector shall have one vote. If a quorum is present with respect to the Industry Sector, the affirmative vote of the majority of the Members within the Industry Sector present and entitled to vote, which must also be a majority of the required quorum, is the act of the Industry Sector. All of the Industry Sector's votes shall be cast consistent with the act of the Industry Sector unless the Industry Sector adopts a fractional voting alternative as described in Section 6.5.3.

6.5.1. Special Voting Requirements. In order to amend the Bylaws, except as provided in Article 19 with respect to the board of directors, two-thirds (2/3) of the Industry Sector votes cast shall be required to approve the proposed amendment. The substance of the proposed amendment must be contained in the notice of the meeting at which the vote will be taken; provided that, the Members may modify a proposed bylaw amendment at the meeting. Two-thirds (2/3) of the Industry Sector votes cast shall be required to approve any proposal to terminate the Corporation. To the extent practicable, all Member votes may be held electronically under such terms and conditions as are approved by the board.

6.5.2. Change of Dues Structure. The Members may change the dues structure by resolution with an affirmative vote of two-thirds (2/3) of the Industry Sector votes cast.

6.5.3. Fractional Voting Alternative. An Industry Sector may adopt fractional voting. Member votes for and against are converted to percentages and multiplied by the applicable sector weight. Abstentions are not counted and do not impact the voting tabulation.

Section 6.6 Quorum. A quorum for a meeting of Members is a majority of the Industry Sector votes entitled to vote at the meeting. A quorum for a meeting of an Industry Sector is a majority of the Members of that Industry Sector present or voting electronically on matters before the meeting. A quorum is necessary for the transaction of business at a meeting of Members. If a quorum is not present, a meeting may be adjourned from time to time for that reason by the Industry Sectors or Members then represented or present.

Section 6.7 Action by Written Ballot. An action that may be taken at a regular or special meeting of Members may be taken without a meeting if the Corporation mails or delivers a written ballot to every Member entitled to vote on the matter. Whenever possible, voting by Industry Sectors for directors shall be by written ballot preceding the regular meeting of the Members.

Approval by written ballot is valid only when the number of votes cast by ballot equals or exceeds the quorum required to be present at a meeting authorizing the action, and the number of approvals equals or exceeds the number of votes that would be required to approve the matter at a meeting at which the total number of votes cast was the same as the number of votes cast by ballot.

Solicitations for votes by written ballot must: (1) indicate the number of responses needed to meet the quorum requirements; (2) state the percentage of approvals necessary to approve the matter; and (3) specify the time by which a ballot must be received by the Corporation in order to be counted. A written ballot may not be revoked.

Section 6.8 Action by Electronic Communication. Any vote of an Industry Sector to elect a board member, or for any other purpose, may be taken by electronic means without a meeting or during a meeting. In addition, a conference among Members by a means of communication through which the participants may simultaneously hear each other during the conference is a meeting of the Members, if the same notice is given of the conference as would be required for a meeting and if the number of persons participating in the conference is a quorum. Participation in a meeting by this means is personal presence at the meeting. A Member may participate in a meeting of the Members by a means of communication through which the Member, other persons participating, and all persons physically present at the meeting may simultaneously communicate with each other during the meeting. Participation in a meeting by this means constitutes personal presence at the meeting.

Section 6.9 Member Representatives; Proxies.

6.9.1. Designation of Representative. Each year prior to the annual meeting of Members, each Member shall designate the individual authorized to vote on Corporation matters on behalf of the Member, in accordance with procedures approved by the board. A Member may change such designation at any time.

6.9.2. Authorization. The individual designated to vote by a Member may appoint a proxy to vote or otherwise act for the Member at any meeting or electronically by signing an appointment form either personally or by an attorney so designated by the Member.

6.9.3. Effective Period. An appointment of a proxy is effective when received by the secretary or other officer or agent authorized to tabulate votes. An appointment is valid for the next regular or specially scheduled meeting or electronic ballot. However, a proxy is not valid for more than sixty (60) days from its date of execution.

6.9.4. Revocation. An appointment of a proxy is revocable by the Member. Appointment of a proxy is revoked by the person appointing the proxy by signing and delivering to the secretary or other officer or agent authorized to tabulate proxy votes. This may be done either in a written statement that the appointment of the proxy is revoked or a subsequent appointment form.

Section 6.10 Reimbursement of Membership Meeting Expenses. The Corporation will be under no obligation to reimburse the Membership for expenses associated with their attendance at regular or special Member meetings.

ARTICLE 7
BOARD OF DIRECTORS

Section 7.1 Management of Corporation. Consistent with these Bylaws, the business and affairs of the Corporation shall be managed by or under the direction of a board of directors. The duties of the board will include, but will not be limited to the following: (1) govern the Corporation and oversee all of its activities; (2) establish and oversee all organizational groups; (3) oversee accomplishment of all functions set forth in any delegation or other agreement with NERC or any governmental entity related to development, monitoring, and enforcement of Reliability Standards and related matters; (4) approve, revise, and enforce Member data and information requirements and related confidentiality requirements; (5) establish and approve an annual budget; (6) represent the Corporation in legal and regulatory proceedings; (7) hire the president. The board of directors shall select a chair and a vice chair from among the members of the board. The board may establish board committees as appropriate.

Section 7.2 Voting. Each director shall have one vote with respect to decisions of the board.

Section 7.3 Composition of the Board of Directors. The board of directors shall consist of twenty-three (23) board members.

Seventeen (17) of the board members are nominated and elected by the Industry Sectors as follows:

(a) Three (3) directors from the Transmission System Operator Sector;

(b) Two (2) directors from the Generator and Power Marketer Sector;

(c) Five (5) directors from the Investor Owned Utility Sector;

(1) Two (2) directors must be from utilities with less than 3,000 megawatts of end-use load.

(2) Three (3) directors must be from utilities with 3,000 megawatts or greater of end-use load.

(d) Two (2) directors from the Cooperative Sector;

(e) Two (2) directors from the Municipal Utility Sector;

(f) One (1) director from the Federal Power Marketing Agency Sector; and

(g) Two (2) directors from the Canadian Utility Sector provided that both directors are not residents of the same Canadian province.

In addition, the board shall nominate two (2) directors from one or two Industry Sectors to be elected by the Members as a Regional Director.

Provided, however, that in choosing directors from an Industry Sector, there shall not be more directors from a particular Industry Sector than there are actual Members of such Industry Sector.

Members shall endeavor to select directors from Industry Sectors among individuals holding senior management or officer positions in Member organizations, and with a view toward ensuring geographic representation of the Corporate Region on the board. No two directors elected from Industry Sectors may be employees of a single Member or employees of Members that are affiliates. To the extent the Members of an Industry Sector do not select a director, that director position shall remain vacant until a director is selected by the Industry Sector.

Four (4) board members shall be Independent Directors nominated by the board of directors and elected by the Members. Independent Directors shall have relevant senior management expertise and experience to the reliable operation of the Bulk Power System in North America.

Section 7.4 **Terms of Directors.** All directors will serve three-year, staggered terms ending on December 31. The initial term of newly elected Independent Directors and Regional Directors may be less than three years if the initial term begins at a time other than January 1. . Any director elected by an Industry Sector may be removed at any time by the affirmative vote of two-thirds (2/3) of the Members of the Industry Sector selecting such director. Regional Directors may be removed at any time by the affirmative vote of two-thirds (2/3) of the Members. An Independent Director may be removed by the affirmative vote of two-thirds (2/3) of the remaining directors. Any director may be removed by the board of directors for non-attendance of three consecutive board meetings.

Section 7.5 **Compensation and Reimbursement.** All directors shall have the right to reimbursement by the Corporation of their actual reasonable travel expenses to board meetings or when specifically selected to represent the Corporation at a business meeting. The board of directors may set reasonable compensation for the service provided by Independent Directors; directors from a Member shall not receive compensation.

Section 7.6 **Vacancies.** If a director resigns, dies, changes corporate affiliation or is removed during the term of office for which elected, the directorship shall thereupon be vacant and shall be filled as soon as practicable and in accordance with the same procedures that the directorship had previously been filled. The successor director shall hold office for the unexpired portion of the term of the director replaced.

Section 7.7 **Meetings; Notice.** An annual meeting of the board of directors shall be held without notice immediately following the annual meeting of the Members to elect the chair and vice chair of the board of directors for the next year. In addition, regular meetings may be held at such time or times as fixed by the board of directors. Schedules of regular meetings of the board of directors shall be published by the secretary and provided to the Membership. Special meetings of the board of directors may be called by the president or by three directors and shall be held at the principal office of the Corporation, or such other place within the Corporate Region as determined by the president after consultation with the board. Notice of the date, time, and place

of a special meeting shall be given by the secretary not less than seven (7) days prior to the meeting by mail, telegram, or electronic communication to each director and the Membership. Except as necessary to discuss personnel issues, litigation or similar sensitive or confidential matters, all meetings of the board of directors shall be open to the Membership and other interested persons.

Section 7.8 Quorum. A majority of the directors currently holding office is a quorum for the transaction of business.

Section 7.9 Board Action. The act of a majority of the directors present at a meeting at which a quorum is present shall be the act of the board of directors, unless the act of a greater number is required by law or these Bylaws, however, in no event will an action of the directors be valid where the action was passed solely by the vote of directors from two Industry Sectors or defeated solely by the vote of directors in a single Industry Sector.

Section 7.10 Action Without a Meeting. An action required or permitted to be taken at a board of directors meeting may be taken by written action, including electronic communication, signed by all of the directors of the Corporation. The written action is effective when signed by the required number of directors, unless a different effective time is provided in the written action.

Section 7.11 Action by Electronic Communication. A conference among directors by a means of communication through which the directors may simultaneously hear each other during the conference is a board meeting if the same notice is given of the conference as would be required for a meeting and if the number of directors participating in the conference is a quorum. Participation in a meeting by this means constitutes personal presence at the meeting. A director may participate in a board meeting by any means of communication through which the director, other directors participating, and all directors physically present at the meeting may simultaneously communicate with each other during the meeting.

ARTICLE 8
ORGANIZATIONAL GROUPS

Section 8.1 Establishment of Organizational Groups. The board of directors shall establish such organizational groups, consisting of committees, sub-committees, task forces and working groups of Members, as are necessary and appropriate to accomplish the purposes of the Corporation in an efficient and cost-effective manner. All organizational groups shall be subject to the direction and control of the board. The membership of organizational groups shall be determined based upon experience, expertise and geographic diversity and to the extent practicable shall include balanced representation of the Industry Sectors.

The board of directors shall establish policies and procedures governing the creation of organizational groups, how they are populated, how voting and related matters are conducted and how they may be reorganized. The board shall conduct a review of all organizational groups of the Corporation on a periodic basis to ensure that the business of the Corporation is conducted in an efficient, cost-effective manner and shall include a statement of its conclusions and resulting actions in the board's report to Members at the annual meeting.

Section 8.2 **Reimbursement.** Consistent with the annual budget of the Corporation, the board may authorize reimbursement by the Corporation for members of organizational groups (other than committees of the whole) of reasonable travel, meals and lodging expenses for organizational group meetings or for representation of the Corporation at other business meetings as authorized by the board. The board of directors may authorize reimbursement for persons acting on behalf of the Corporation, as necessary in the interests of the Corporation.

ARTICLE 9
OFFICERS

Section 9.1 **Officers.** The officers of the Corporation shall include a president, a secretary, a treasurer and any other officers as may be elected or appointed in accordance with the provisions of this Article. The board of directors may elect or appoint any additional officers that it deems desirable, such other officers to have the authority and perform the duties prescribed by the board of directors. The same individual may hold any number of offices, except that of president.

Section 9.2 **Election and Term of Office.** The officers of the Corporation shall be elected by the board of directors. Each officer shall hold office at the pleasure of the board. New officers may be created and the positions filled at any meeting of the board of directors. Each elected officer shall hold office until his or her successor has been duly elected and qualified.

Section 9.3 **Removal.** Any officer elected by the board of directors may be removed by the affirmative vote of two-thirds (2/3) of the board of directors whenever in its judgment the best interests of the Corporation would be served thereby, but such removal shall be without prejudice to the contract rights, if any, of the officer so removed. Election or appointment of an officer or agent shall not of itself create contract rights.

Section 9.4 **Vacancies.** A vacancy in any office because of death, resignation, removal, disqualification, or otherwise, may be filled by the board of directors for the unexpired portion of the term.

Section 9.5 **President.** The president shall be, in the discretion of the board of directors, either an employee of or contractor to the Corporation and shall:

(a) be the chief executive officer of the Corporation;

(b) sign certificates of Membership, and may sign any deeds, mortgages, deeds of trust, notes, bonds, contracts or other instruments authorized by the board of directors to be executed, except in cases in which the signing and execution thereof shall be expressly delegated by the board of directors or by these Bylaws to some other officer or agent of the Corporation; and

(c) perform all duties incident to the office of president and chief executive officer, including hiring and directing staff, and such other duties as may be prescribed by the board of directors from time to time.

Section 9.6 **Secretary.** The secretary shall ensure that the following duties are carried out:

(a) the minutes of the meetings of the Members and of the board of directors are recorded;

(b) all required notices are duly given in accordance with these Bylaws and as required by law;

(c) a register of the current names and addresses of the Membership is maintained;

(d) a complete copy of the Articles of Incorporation and Bylaws of the Corporation containing all amendments thereto are kept on file at all times, which copies shall always be open to the inspection of the Membership; and

(e) generally perform all duties incident to the office of secretary and such other duties as may be prescribed by the board of directors from time to time.

Section 9.7 **Treasurer.** The treasurer shall be responsible for the following activities:

(a) maintain custody of all funds and securities of the Corporation;

(b) receipt of and the issuance of receipts for all monies due and payable to the Corporation and for deposit of all such monies in the name of the Corporation in such bank or banks or financial institutions as shall be selected by the board of directors; and

(c) generally perform all duties incident to the office of treasurer and such other duties as may be prescribed by the board of directors from time to time.

ARTICLE 10
CERTIFICATES OF MEMBERSHIP

Section 10.1 **Certificates of Membership.** The board of directors may provide for the issuance of certificates evidencing Membership in the Corporation, which certificates shall be in such form as may be determined by the board.

ARTICLE 11
BOOKS AND RECORDS

Section 11.1 **Books and Records; Financial Statements.** The Corporation shall keep at its registered office correct and complete copies of its Articles of Incorporation and Bylaws, accounting records, and minutes of meetings of Members, board of directors, and committees having any of the authority of the board of directors. A Member or Adjunct Member, or the agent or attorney of a Member or Adjunct Member, may inspect all books and records and voting agreements for any proper purpose at any reasonable time. Upon request, the Corporation shall give the Member or Adjunct Member a statement showing the financial result of all operations and

transactions affecting income and surplus during its last annual accounting period and a balance sheet containing a summary of its assets and liabilities as of the closing date of the accounting period.

ARTICLE 12
FISCAL YEAR

Section 12.1 Fiscal Year. The fiscal year of the Corporation shall be the calendar year.

ARTICLE 13
TRANSFER OF ASSETS

Section 13.1 Member Approval Not Required. Subject to the restrictions set forth in the Certificate of Incorporation, the Corporation, by affirmative vote of the board of directors, may sell, lease, transfer, or dispose of its property and assets in the usual and regular course of its activities and grant a security interest in all or substantially all of its property and assets in the usual and regular course of its activities, upon those terms and conditions and for those considerations, which may be money, securities, or other instruments for the payment of money or other property, as the board of directors considers expedient, in which case no Member approval is required.

Section 13.2 Member Approval; When Required. Subject to the restrictions set forth in the Certificate of Incorporation, the Corporation may sell, lease, transfer, or dispose of all or substantially all of its property and assets, including its good will, not in the usual and regular course of its activities, upon those terms and conditions and for those considerations, which may be money, securities, or other instruments for the payment of money or other property, as the board of directors considers expedient only when approved at a regular or special meeting of the Members by the affirmative vote of two-thirds (2/3) of all the Members. Notice of the meeting must be given to the Membership. The notice must state that a purpose of the meeting is to consider the sale, lease, transfer, or other disposition of all or substantially all of the property and assets of the Corporation.

ARTICLE 14
CONTRACTS, CHECKS, DEPOSITS, AND GIFTS

Section 14.1 Contracts. The board of directors may authorize any officer or officers or agent or agents of the Corporation, in addition to the officers so authorized by these Bylaws, to enter into any contract or execute and deliver any instrument in the name of and on behalf of the Corporation, and such authority may be general or may be confined to specific instances.

Section 14.2 Checks, Drafts, or Orders. All checks, drafts, or orders for the payment of money, notes, or other evidences of indebtedness issued in the name of the Corporation, shall be signed by such officer or officers or agent or agents of the Corporation, and in such manner as shall from time to time be determined by resolution of the board of directors.

Section 14.3 Deposits. All funds of the Corporation shall be deposited to the credit of the Corporation in such banks, trust companies, or other depositories as the board of directors may select.

Section 14.4 Gifts. The board of directors may accept on behalf of the Corporation any contribution, gift, bequest, or devise for any purpose of the Corporation.

ARTICLE 15
INSURANCE, LIABILITY, AND INDEMNIFICATION

Section 15.1 Insurance. The president is authorized to procure insurance to protect the Corporation against damages arising out of or related to any directive, order, procedure, action or requirement of the Corporation.

Section 15.2 Limitations on Liability. No director, officer, agent, employee, or other representative of the Corporation, and no corporation or other business organization that employs a director of the Corporation, or any director, officer, agent or employee of such corporation or other business organization, shall be personally liable to the Corporation or any Member or Adjunct Member of the Corporation for any act or omission on the part of any such director, officer, agent, employee, or other representative of the Corporation, which was performed or omitted in good faith in his official capacity as a director, officer, agent, employee, or other representative of the Corporation. However, this release of liability shall not operate to release such a director, officer, agent, employee or other representative of the Corporation from any personal liability resulting from willful acts or omissions knowingly or intentionally committed or omitted by him in breach of these Bylaws for improper personal benefit or in bad faith.

Section 15.3 Indemnification. It is the intent of the Corporation to indemnify its directors, officers, agents, employees, or other representatives to the maximum extent allowed by law consistent with these Bylaws. Each director, officer, agent, employee, or other representative of the Corporation shall be indemnified by the Corporation against all judgments, penalties, fines, settlements, and reasonable expenses, including legal fees, incurred by him as a result of, or in connection with, any threatened, pending or completed civil, criminal, administrative, or investigative proceedings to which he may be made a party by reason of his acting or having acted in his official capacity as a director, officer, agent, employee, or representative of the Corporation, or in any other capacity which he may hold at the request of the Corporation, as its representative in any other organization, subject to the following conditions:

(a) Such director, officer, agent, employee, or other representative must have conducted himself in good faith and, in the case of criminal proceedings, he must have had no reasonable cause to believe that his conduct was unlawful. When acting in his official capacity, he must have reasonably believed that his conduct was in the best interests of the Corporation, and, when acting in any other capacity, he must have reasonably believed that his conduct was at least not opposed to the best interests of the Corporation.

(b) If the proceeding was brought by or on behalf of the Corporation, however, indemnification shall be made only with respect to reasonable expenses referenced above. No indemnification of any kind shall be made in any such proceeding in

which the director, officer, agent, employee, or other representative shall have been adjudged liable to the Corporation.

(c) In no event, however, will indemnification be made with respect to any described proceeding that charges or alleges improper personal benefit to a director, officer, agent, employee, or other representative and where liability is imposed upon him on the basis of the receipt of such improper personal benefit.

(d) In order for any director, officer, agent, employee, or other representative to receive indemnification under this provision, he shall vigorously assert and pursue any and all defenses to those claims, charges, or proceedings covered hereby, which are reasonable and legally available and shall fully cooperate with the Corporation or any attorneys involved in the defense of any such claim, charges, or proceedings on behalf of the Corporation.

(e) No indemnification shall be made in any specific instance until it has been determined by the Corporation that indemnification is permissible in that specific case, under the standards set forth herein and that any expenses claimed or to be incurred are reasonable. These two (2) determinations shall be made by a majority vote of at least a quorum of the board consisting solely of directors who were not parties to the proceeding for which indemnification or reimbursement of expenses is claimed. If such a quorum cannot be obtained, a majority of at least a quorum of the full board, including directors who are parties to said proceeding, shall designate a special legal counsel who shall make said determinations on behalf of the Corporation. In making any such determinations, the termination of any proceeding by judgment, order, settlement, conviction, or upon plea of nolo contendere, or its equivalent, shall not, in and of itself, be conclusive that the person did not meet the standards set forth herein.

(f) Any reasonable expenses, as shall be determined above, that have been incurred by a director, officer, agent, employee, or other representative who has been made a party to a proceeding as defined herein, may be paid or reimbursed in advance upon a majority vote of a quorum of the full board, including those who may be a party to the same proceeding. However, such director, officer, agent, employee, or other representative shall have provided the Corporation with (i) a written affirmation under oath that he, in good faith, believes that he has met the conditions for indemnification herein, and (ii) a written undertaking that he shall repay any amounts advanced, with interest accumulated at a reasonable rate, if it is ultimately determined that he has not met such conditions. In addition to the indemnification and reimbursement of expenses provided herein, the president shall purchase insurance that would protect the Corporation, its directors, officers, agents, employees, or other representatives against reasonably expected liabilities and expenses arising out of the performance of their duties for the Corporation.

ARTICLE 16
PARTICIPATION BY REGULATORY PARTICIPANTS

Section 16.1 Regulatory Participants. All Regulatory Participants shall be entitled to be Adjunct Members.

ARTICLE 17
PARTICIPATION BY FEDERAL POWER MARKETING ADMINISTRATIONS

Section 17.1 Power Marketing Administrations Participation. The participation by the United States through Federal power marketing administrations (PMA) in the Corporation is subject in all respects to acts of Congress and to regulations of the Secretary of Energy established thereunder. This reservation includes, but is not limited to, the statutory limitations upon the authority of the Secretary of Energy to submit disputes arising hereunder to arbitration. In the event of a conflict between this Article 17 and any other Article of these Bylaws, this Article 17 shall have precedence with respect to the application of these Bylaws to the United States.

Section 17.2 Failure of Congress to Make Appropriations. Where activities provided for herein extend beyond the current fiscal year, continued expenditures by the United States are contingent upon Congress making the necessary appropriations required for the continued performance of the obligations of the PMA hereunder. In case such appropriations are not made, the Corporation and its Members hereby release the PMA from its contractual obligations under these Bylaws and from all liability due to the failure of Congress to make such appropriation.

Section 17.3 Inapplicability of Bylaws to Congressional Members and Delegates. No member of, or delegate to, Congress shall be admitted to any share or part of, or to any benefit that may have arisen from, these Bylaws, but this restriction shall not be construed to extend to these Bylaws if made with a corporation or company for its general benefit.

Section 17.4 No Solicitation of Power Marketing Administration Participation. The Corporation and its Membership warrant that no Person or selling agency has been employed or retained to solicit or secure participation by a PMA in the Corporation upon an agreement or understanding for a commission, percentage, brokerage or contingent fee, excepting *bona fide* employees or *bona fide* established commercial or selling agencies maintained by the Membership for the purpose of securing business. For breach or violation of this warranty, a PMA shall have the right to annul its participation in the Corporation without liability or, in its discretion, to deduct from its dues or fees the full amount of such commission, percentage, brokerage, or contingent fee.

Section 17.5 Provisions Applicable to the Corporation. For the purpose of this Section 17.5 the term "Contract" shall mean these Bylaws and the term "Contractor" shall mean the Corporation. During the performance of this Contract, the Contractor agrees to the following provisions.

17.5.1.No Discrimination. Section 202 of the Executive Order No. 11246, 30 Fed. Reg. 12319 (1965), as amended by Executive Order No. 12086, 43 Fed. Reg. 46501 (1978), which provides, among other things, that the Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin, is incorporated by reference in the Contract.

17.5.2.Contract Work Hours and Safety Standards Act. The Contract, to the extent that it is of a character specified in Section 103 of the Contract Work Hours and Safety Standards Act, 40 U.S.C. § 329 (1986) (the "Act"), is subject to the provisions of

the Act, 40 U.S.C. §§ 327-333 (1986), and to regulations promulgated by the Secretary of Labor pursuant to the Act.

17.5.3.Imprisonment. The Contractor agrees not to employ any person undergoing sentence of imprisonment in performing the Contract except as provided by 18 U.S.C. § 4082(c)(2) and Executive Order 11755, 39 Fed. Reg. 779 (1973).

ARTICLE 18
HEARINGS AND DISPUTE RESOLUTION

Section 18.1 Hearings. Except as otherwise provided in applicable agreements and/or law governing Membership in the Corporation, the Corporation shall be responsible for making final determinations regarding whether a registered entity has violated a Reliability Standard in accordance with the NERC Rules of Procedure.

Section 18.2 Disputes. Dispute resolution procedures will be established by the board of directors for disputes between Members, or between a Member and the Corporation, for issues arising under these Bylaws. Determinations related to violations of Reliability Standards will be resolved in accordance with the NERC Rules of Procedure. Except as otherwise provided in applicable agreements and/or law governing a Member's membership in the corporation.

ARTICLE 19
AMENDMENT OF BYLAWS

Section 19.1 Changes to the Bylaws. The power to adopt, amend, or repeal these Bylaws is vested in the Members as set forth in Section 6.5 of these Bylaws; provided however, upon the passage of any federal reliability legislation and/or the adoption of related requirements and procedures by NERC or any regulatory agency with jurisdiction, the board of directors shall have authority upon a two-thirds (2/3) vote to amend these Bylaws as necessary and appropriate to comply with such law and related requirements.

ATTACHMENT 2

Amended Bylaws –to the Amended and Restated Delegation Agreement Between

North American Electric Reliability Corporation

and

Midwest Reliability Organization – **Redline**

BYLAWS OF THE

MIDWEST RELIABILITY ORGANIZATION, INC.

As amended through ~~May 4, 2015~~xxx xx, 2018

-Approved by the MRO Board of Directors on ~~April 2, 2015 and by~~July 26, 2017February 27, 2018; the MRO Members on ~~May 4, 2015;~~ March 21, 2018; the North American Electric Reliability Corporation Board of Trustees on May 10, 2018

Approved by FERC Effective ~~September 30, 2015~~[proposed date]

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BYLAWS
OF THE
MIDWEST RELIABILITY ORGANIZATION, INC.
a Delaware nonprofit corporation
(the "Corporation")

ARTICLE 1
DEFINITIONS

Section 1.1 Adjunct Member. "Adjunct Member" means an entity that: (1) is not eligible to belong to an Industry Sector; (2) has a material interest in reliability issues in the Corporation's Region and (3) becomes an Adjunct Member of the Corporation.

Section 1.2 Affiliate. "Affiliate" means with respect to any entity, any other entity that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such entity, as determined in the sole discretion of the board of directors of the Corporation. For this purpose, "control" may be presumed by the direct or indirect ownership of 50 percent or more of the outstanding voting capital stock or other equity interests having ordinary voting power. A member of, or owner of an interest in, a transmission company that FERC has found meets the independence requirements for a regional transmission organization shall not be deemed to be an affiliate of such transmission company.

Section 1.3 Bulk Power System. "Bulk Power System" means (1) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (2) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in local distribution of electric energy. The term Bulk Power System shall be interpreted consistently with any definition given by NERC.

Section 1.4 Bulk Power System Users. "Bulk Power System Users" means any entity that sells, purchases, or transmits electric power over the Bulk Power System, or that owns, operates or maintains facilities or control systems that are part of the Bulk Power System.

Section 1.5 Canadian ~~Utilities~~Utility. "Canadian ~~Utilities~~Utility" means ~~any~~an entity that is a government-owned utility serving in Canada within the Corporate Region.

Section 1.6 Corporation. "Corporation" means Midwest Reliability Organization, Inc.

Section 1.7 Cooperative. "Cooperative" means an entity serving within the Corporate Region ~~which~~ that generally has the following characteristics: (1) private independent electric utility; (2) incorporated under the laws of a state in which they operate; (3) established to provide electric service to its members; (4) owned by the consumers they serve; and (5) governed by a board of directors elected from the membership. This sector includes Generation and Transmission Cooperatives and Public Utility Districts.

Section 1.8 Corporate Region. "Corporate Region" means the geographic area boundaries of the Bulk ~~-~~Power Systems as designated by the then current delegation agreement.

Section 1.9 FERC. "FERC" means the Federal Energy Regulatory Commission.

Section 1.10 Federal Power Marketing ~~Agencies~~Agency. "Federal Power Marketing Agency~~yies"~~ means ~~agencies~~an agency of the federal government created to market power within the Corporate Region.

Section 1.11 ~~Generators~~Generator and Power ~~Marketers~~Marketer. "~~Generators~~Generator and Power ~~Marketers~~Marketer" means ~~any~~an entity that owns or operates more than 50 MW of generation in the Corporate Region, or is a power marketer doing business in the Corporate Region, and that does not qualify also to participate in the Investor ~~-~~Owned Utility, Cooperative, Municipal Utility, Federal Power Marketing Agency or Canadian Utility~~ies~~ Sectors.

Section 1.12 Good Utility Practice. "Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts, which~~,~~ in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. ~~-~~Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the Corporate Region.

Section 1.13 Independent Director. "Independent Director" means an individual who is not (1) an officer or employee of the Corporation; (2) a member, director, officer or employee of a Member or Adjunct Member of the Corporation; (3) a director, officer or employee of any r~~R~~egistered e~~E~~ntity on the NERC registry; or (4) reasonably ~~-~~perceived as having a direct financial interest in the outcome of a decision by the board of directors and who (a) does not have any other relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a director and (b) meets any additional requirements of independence established by the board of directors.

Section 1.14 Industry Sector(s). "Industry Sector or Sector(s)" means a group of Bulk~~-~~Power System Users in the Corporate Region with substantially similar reliability interests, as determined by these Bylaws. ~~-~~The Industry Sectors shall include the following:~~-~~ (1) Transmission System Operators; (2) Generators and Power Marketers; (3) Investor Owned Utilities (4) Cooperatives; (5) Municipal Utilities (6) Federal Power Marketing Agencies; and (7) Canadian Utilities.

Section 1.15 Investor Owned Utility. "Investor Owned Utility" means ~~any~~a for-profit entity that owns and operates a distribution system and serves end-use load within the Corporate Region pursuant to an obligation to serve under state, federal or provincial law, including a default service obligation, or pursuant to a tariff by which the entity offers service to the general public.

Section 1.16 Member. "Member" means any entity eligible to belong to an Industry Sector(s) that becomes a Member of the Corporation.

Section 1.17 Membership. "Membership" includes Adjunct Members and Members of the Corporation. ~~–~~Membership in the Corporation is voluntary and does not affect NERC registration.

Section 1.18 Municipal ~~Utilities~~Utility. "Municipal Utility~~ies~~" means ~~any~~an entity that is an electric utility that is owned by a state or municipality, or group of municipalities, including a joint action agency, which serves within the Corporate Region.

Section 1.19 NERC. "NERC" means the North American Electric Reliability Corporation or a successor entity.

Section 1.20 Person. "Person" means any natural person, corporation, ~~Cooperative~~cooperative, partnership, association, or other private or public entity.

Section 1.21 Public Utility District. "Public Utility District" means an entity that is a state political or governmental subdivision ~~which~~ that owns electric generation, transmission and distribution facilities and that was created and organized under state statutes that are different than those that Municipal Utilities in the same state are created and organized under.

Section 1.22 Regional Director. "Regional Director" means a director who is an employee of a Member and meets the qualifications set out in these Bylaws for directors elected from an Industry Sector.

Section 1.22Section 1.23 Regional Entity. "Regional Entity" means an entity having authority pursuant to a delegation agreement with NERC and pursuant to any agreements or laws relating to the Corporation's functions in Canada.

Section 1.23Section 1.24 Regulatory Participant. "Regulatory Participant" means any state or provincial regulatory agencies in the Corporate Region exercising authority over the rates, terms or conditions of electric service of an entity other than itself within the Corporate Region, or the planning, siting, construction or operation of electric facilities of an entity other than itself within the Corporate Region, as well as any representatives of FERC, regional advisory bodies that may be established by FERC, or representatives of any federal regulator or agency.

Section 1.24Section 1.25 Reliability Standard. "Reliability Standard" means a NERC R~~r~~eliability S~~s~~tandard, duly in effect, under the rules, regulations and laws governing such standards, to provide for reliable operation of the Bulk ~~-~~Power System.

Section 1.25Section 1.26 Transmission System Operator. "Transmission System Operator" means an entity that operates or controls operation of high voltage transmission facilities within the Corporate Region (more than 300 miles of transmission at 100 kV or greater) that does not also own, operate or control generation within the Corporate Region, except to the limited

extent permitted by FERC for independent transmission organizations with respect to ancillary service obligations. Transmission System Operators include: (1) regional transmission organizations; (2) independent transmission providers; (3) independent system operators; (4) and transmission-only companies.

ARTICLE 2
PURPOSE

Section 2.1 Purpose. The Corporation will be a Regional Entity within the NERC structure for the purpose of preserving and enhancing electric service reliability, adequacy and security in the Corporate Region and other interconnected regions for the benefit of all end-users of electricity in the Corporate Region.

Section 2.2 Activities. In support and furtherance of its purpose, the Corporation's responsibilities shall include, but not be limited to:~~-~~ (1) proposing Reliability Standards, including regional variances or regional Reliability Standards required to maintain and enhance electric service reliability, adequacy and security in the Corporate Region; (2) assessing compliance with and enforcing Reliability Standards, to the extent authorized by applicable agreements and/or law governing a Member's membership in the Corporation; (3) conducting investigations and data analysis on disturbances, system events, and related matters; (4) conducting long-term assessments of reliability within the Corporate R~~r~~egion; and (5) other related activities.

Section 2.3 Not-for-Profit Corporation. The Corporation is operated as a Delaware non-stock, nonprofit corporation and is organized pursuant to the general corporation law of the State of Delaware. The Corporation shall be exempt from federal income taxation pursuant to Section 501(c) of the Internal Revenue Code of 1986, as amended (hereinafter the "Code"). The Corporation shall not engage directly or indirectly in any activity ~~which~~ that would invalidate its status as an organization exempt from taxation under Section 501(a) of the Code as an organization described in Section 501(c)(3) of the Code. No part of the net income to the Corporation shall inure to the benefit of or be distributed to its directors, officers, members or other private persons, except that the Corporation shall be authorized and empowered to pay reasonable compensation for services actually rendered.

ARTICLE 3
POWERS

Section 3.1 Powers. The Corporation shall have the power to engage in any lawful act or activity for which corporations may be organized under the general corporation law of the State of Delaware, subject to any limitations provided in applicable federal, provincial or state law or in the Corporation's certificate of incorporation or these Bylaws.

ARTICLE 4
OFFICES

Section 4.1 Offices. The principal office of the Corporation shall be located initially within the Corporate Region, at such location as the board of directors may from time to time determine, giving consideration to the total cost to the Corporation and convenience of travel for staff, Members and Regulatory Participants. Once established, the principal office may remain in its location, even if outside the Corporate Region.

ARTICLE 5
MEMBERS

Section 5.1 Classes of Members. The Corporation shall have two classes of members; Adjunct Members and Members.

Section 5.2 Affiliates. Each Affiliate of a Member or Adjunct Member may separately be a Member or Adjunct Member, respectively.

Section 5.3 Admission of Members and Adjunct Members. New Members and Adjunct Members may join the Corporation upon submittal of an application, in a form approved by the president, and payment of the fees as established by the Corporation. An entity applying to be a Member shall designate the Industry Sector to which it belongs. A Member may change its Industry Sector designation once each calendar year, by providing notice to the president at least sixty (60) days prior to the beginning of such year. The president shall review a membership application and may request demonstration by the applicant that it qualifies for membership in a particular Industry Sector or as an Adjunct Member. Any dispute with respect to a Member's or Adjunct Member's qualifications shall be resolved by the board of directors. The president shall have authority to approve an application for membership, subject to review by the board of directors.

Section 5.4 Voting Rights. Each Member in good standing shall be entitled to one vote in the Industry Sector in which it is a Member, on matters submitted to a vote of Members. A Member delinquent in payment of its dues, fees or other obligations to the Corporation shall not be entitled to a vote.

Section 5.5 Transfer of Membership. Membership or a right arising from such membership may not be transferred except to any Person succeeding to all or substantially all of the assets of the Member or Adjunct Member. The president shall have authority to approve any such transfer, subject to review by the board of directors.

Section 5.6 Obligations of Members and Adjunct Members. By applying for Membership the applicant acknowledges that it is authorized and agrees to comply with, Reliability Standards to the extent such standards are applicable, and other obligations as set forth in these Bylaws or duly adopted by the board of directors in order to achieve the purposes of the Corporation. Such obligations include but are not limited to requirements to provide data and

information needed to perform the functions of the Corporation and the payment of dues and any authorized penalties, including penalties and other obligations resulting from violations of Reliability Standards assessed in accordance with NERC rules and subject to applicable regulatory approval.

Section 5.7 Withdrawal. Withdrawal from Membership in the Corporation is accomplished by providing written notice to the president of the Corporation of such intent to withdraw. Such notice shall specify a date, not earlier than thirty (30) days from the date of notice, on which the withdrawal shall become effective; provided however, that any such withdrawing Member or Adjunct Member shall remain liable to the Corporation for any fees, dues, sanctions or obligations to the Corporation incurred during the entity's Membership, as well as its share of any obligations of the Corporation for the current fiscal year. If notice is given after October 1 of the current calendar year, the entity will also be liable for any fees and dues included in the budget for the following fiscal year. Section 5.7 does not apply to any fees, dues, or obligations associated with the Corporation responsibilities under delegated authority from NERC or applicable regulatory authorities.

Section 5.8 Budget and Fees. The board of directors shall propose to NERC a budget for delegated functions exercised by the Corporation pursuant to a delegation agreement with NERC and pursuant to any agreements or laws relating to the Corporation's functions in Canada. For those functions outside the scope of the Corporation's delegated functions, the board of directors may from time to time fix the amount of dues, assessments, or fees, if any, and determine the methods of collection, consistent with this Section, the regulations of applicable government authorities, and any resolutions duly adopted by the Members under Section 6.5.2 of these Bylaws.

ARTICLE 6
MEETING OF MEMBERS

Section 6.1 Annual Meeting of Members. The Members shall hold an annual meeting each calendar year in December, or at such other time specified by the board of directors, in order for Members to review the proposed budget and operations of the Corporation. Adjunct Members may attend the annual meeting of Members. The Membership shall be entitled to at least thirty (30) days prior written notice of the annual meeting. At or before the annual meeting of Members: (1) each Industry Sector shall elect the successor(s), if any, for any director(s) from its Industry Sector whose term will expire before the next annual meeting of the Members, provided however, that any Industry Sector may elect a successor director representing such Industry Sector prior to such annual meeting, in accordance with the provisions of this Article 6, in which case the election of such succeeding director(s) shall be reported to the Corporation at such annual meeting; (2) the Members will elect Independent Directors, if any; (3) the president and treasurer shall report on the activities and financial condition of the Corporation; and (4) the Members shall consider and act upon such other matters as may be raised, consistent with the notice of the annual meeting. The failure to hold an annual meeting in accordance with these Bylaws shall not affect the validity of a corporate action.

Section 6.2 Special Meetings of Members.

6.2.1. Who May Call. Special meetings of the Members may be called by six (6) members of the board of directors, by the president, or if at least 10 percent of the Members sign, date, and deliver to the president one or more written demands for a special meeting describing the purpose for which it is to be held. Adjunct Members may attend special meetings of the Members.

6.2.2. Notice of Meeting. Within fifteen (15) days after receipt of a demand for a special meeting from Members, the president shall cause a special meeting to be called and held on notice to the Membership no later than forty-five (45) days after receipt of the demand. If the president fails to cause a special meeting to be called and held as required by this section, a Member making the demand may call the meeting by giving notice under Section 6.3. In either event, notice of the meeting and the costs of the meeting shall be at the expense of the Corporation.

6.2.3. Time and Place of Special Meetings. Special meetings of the Members shall be held at a location designated by the president or the board of directors. If a special meeting is demanded by the Members, the meeting must be held in a facility of appropriate size to accommodate the Membership and at a location within the Corporate Region.

6.2.4. Notice Requirements; Business Limited. The notice of a special meeting must contain a statement of the purposes of the meeting. The business transacted at a special meeting is limited to the purposes stated within the notice of the meeting. Business transacted at a special meeting that is not included in those stated purposes is voidable by, or on behalf of, the Corporation, unless 90 percent of the Members entitled to vote were present at such meeting or have waived notice of the meeting under Section 6.3.

Section 6.3 Notice Requirements.

6.3.1. To Whom Given. Notice of meetings of Members must be given to the Membership as of the record date determined under Section 6.4. If the meeting is an adjourned meeting and the date, time, and place of the meeting were announced at the time of the adjournment, notice is not required unless a new record date for the adjourned meeting is or must be fixed.

6.3.2. When Given; Contents. In all cases where a specific minimum notice period has not been fixed by law or these Bylaws, the notice must be given at least five (5) days before the date of a meeting and not more than sixty (60) days before the date of a meeting. The notice must contain the date, time and place of the meeting, and an agenda of the matters upon which action may be taken at the meeting. A matter may be added to the agenda of a meeting at the meeting upon the affirmative vote of three-quarters (3/4) of the Industry Sector votes cast on a motion to amend the agenda.

6.3.3. Waiver of Notice; Objections. A Member may waive notice of a meeting of Members. A waiver of notice by a Member entitled to notice is effective whether given before, at, or after the meeting, and whether given in writing, or by attendance. Attendance

by a Member at a meeting is a waiver of notice of that meeting, unless the Member objects at the beginning of the meeting to the transaction of business because the meeting is not lawfully called or convened, or objects before a vote on an item of business because the item may not lawfully be considered at that meeting and does not participate in the consideration of the item at that meeting.

Section 6.4 Record Date; Determining Members Entitled to Notice and Vote. The board of directors may fix a date not more than forty (40) days before the date of a meeting of Members as the date for the determination of the Membership entitled to notice of the meeting and the Members entitled to vote at the meeting. When a date is so fixed, only the Membership on that date is entitled to notice and only the Members are entitled to vote at a meeting of the Members unless the board of directors fixes a new date for determining the right to notice and to vote, which it must do if the meeting is adjourned to a date more than sixty (60) days after the record date for determining Membership entitled to notice of the original meeting.

Section 6.5 Right to Vote; Act of Members. Voting of the Members shall be by Industry Sector, with each Industry Sector entitled to the same number of votes as it has directors on the board. If a quorum is present, except with respect to amendments of these Bylaws, modification of a budget approved by the board of directors or termination of the Corporation, the affirmative vote of the majority of the Industry Sector votes present and entitled to vote, which must also be a majority of the required quorum, is the act of the Members, however, in no event will an action of the Members be valid where the action was passed solely by the vote of Members from two Industry Sectors or defeated solely by the vote of Members in a single Industry Sector. Within an Industry Sector, each Member within the Industry Sector shall have one vote. If a quorum is present with respect to the Industry Sector, the affirmative vote of the majority of the Members within the Industry Sector present and entitled to vote, which must also be a majority of the required quorum, is the act of the Industry Sector. All of the Industry Sector's votes shall be cast consistent with the act of the Industry Sector unless the Industry Sector adopts a fractional voting alternative as described in Section 6.5.3.

6.5.1. Special Voting Requirements. In order to amend the Bylaws, except as provided in Article 19 with respect to the board of directors, two-thirds (2/3) of the Industry Sector votes cast shall be required to approve the proposed amendment. The substance of the proposed amendment must be contained in the notice of the meeting at which the vote will be taken; provided that, the Members may modify a proposed bylaw amendment at the meeting. Two-thirds (2/3) of the Industry Sector votes cast shall be required to approve any proposal to terminate the Corporation. To the extent practicable, all Member votes may be held electronically under such terms and conditions as are approved by the bBoard.

6.5.2. Change of Dues Structure. The Members may change the dues structure by resolution with an affirmative vote of two-thirds (2/3) of the Industry Sector votes cast.

6.5.3. Fractional Voting Alternative. An Industry Sector may adopt fractional voting. Member votes for and against are converted to percentages and multiplied by the

applicable sector weight. –Abstentions are not counted and do not impact the voting tabulation.

Section 6.6 Quorum. A quorum for a meeting of Members is a majority of the Industry Sector votes entitled to vote at the meeting. -A quorum for a meeting of an Industry Sector is a majority of the Members of that Industry Sector present or voting electronically on matters before the meeting. -A quorum is necessary for the transaction of business at a meeting of Members.- If a quorum is not present, a meeting may be adjourned from time to time for that reason by the Industry Sectors or Members then represented or present.

Section 6.7 Action by Written Ballot. An action that may be taken at a regular or special meeting of Members may be taken without a meeting if the Corporation mails or delivers a written ballot to every Member entitled to vote on the matter. –Whenever possible, voting by Industry Sectors for directors shall be by written ballot preceding the regular meeting of the Members.

Approval by written ballot is valid only when the number of votes cast by ballot equals or exceeds the quorum required to be present at a meeting authorizing the action, and the number of approvals equals or exceeds the number of votes that would be required to approve the matter at a meeting at which the total number of votes cast was the same as the number of votes cast by ballot.

Solicitations for votes by written ballot must: -(1) indicate the number of responses needed to meet the quorum requirements; (2) state the percentage of approvals necessary to approve the matter; and (3) specify the time by which a ballot must be received by the Corporation in order to be counted. -A written ballot may not be revoked.

Section 6.8 Action by Electronic Communication. Any vote of an Industry Sector to elect a board member, or for any other purpose, may be taken by electronic means without a meeting or during a meeting.– In addition, a conference among Members by a means of communication through which the participants may simultaneously hear each other during the conference is a meeting of the Members, if the same notice is given of the conference as would be required for a meeting and if the number of persons participating in the conference is a quorum. Participation in a meeting by this means is personal presence at the meeting.– A Member may participate in a meeting of the Members by a means of communication through which the Member, other persons participating, and all persons physically present at the meeting may simultaneously communicate with each other during the meeting. –Participation in a meeting by this means constitutes personal presence at the meeting.

Section 6.9 Member Representatives; Proxies.

6.9.1. Designation of Representative. Each year prior to the annual meeting of Members, each Member shall designate the individual authorized to vote on Corporation matters on behalf of the Member, in accordance with procedures approved by the board. A Member may change such designation at any time.

6.9.2. Authorization. The individual designated to vote by a Member may appoint a proxy to vote or otherwise act for the Member at any meeting or electronically by signing an appointment form either personally or by an attorney so designated by the Member.

6.9.3. Effective Period. An appointment of a proxy is effective when received by the secretary or other officer or agent authorized to tabulate votes. An appointment is valid for the next regular or specially scheduled meeting or electronic ballot. However, a proxy is not valid for more than sixty (60) days from its date of execution.

6.9.4. Revocation. An appointment of a proxy is revocable by the Member. Appointment of a proxy is revoked by the person appointing the proxy by signing and delivering to the secretary or other officer or agent authorized to tabulate proxy votes. This may be done either in a written statement that the appointment of the proxy is revoked or a subsequent appointment form.

Section 6.10 Reimbursement of Membership Meeting Expenses. The Corporation will be under no obligation to reimburse the Membership for expenses associated with their attendance at regular or special Member meetings.

ARTICLE 7
BOARD OF DIRECTORS

Section 7.1 Management of Corporation. Consistent with these Bylaws, the business and affairs of the Corporation shall be managed by or under the direction of a board of directors. The duties of the board will include, but will not be limited to the following: (1) govern the Corporation and oversee all of its activities; (2) establish and oversee all organizational groups; (3) oversee accomplishment of all functions set forth in any delegation or other agreement with NERC or any governmental entity related to development, monitoring, and enforcement of Reliability Standards and related matters; (4) approve, revise, and enforce Member data and information requirements and related confidentiality requirements; (5) establish and approve an annual budget; (6) represent the Corporation in legal and regulatory proceedings; (7) hire the president. The board of directors shall select a chair and a vice chair from among the members of the board. The board may establish board committees as appropriate.

Section 7.2 Voting. Each director shall have one vote with respect to decisions of the board.

Section 7.3 Composition of the Board of Directors. The board of directors shall consist of ~~nineteen (19~~twenty-three (23) board members~~, seventeen~~.

Seventeen (17) of the board members are nominated and elected by the Industry Sectors as follows:

(a) Three (3) directors from the Transmission System ~~Operators~~Operator Sector;

(b) Two (2) directors from the ~~Generators~~Generator and Power ~~Marketers~~Marketer Sector;

(c) Five (5) directors from the Investor Owned ~~Utilities~~Utility Sector;

(1) Two (2) directors must be from utilities with less than 3,000 megawatts of end-use load.

(2) Three (3) directors must be from utilities with 3,000 megawatts or greater of end-use load.

(d) Two (2) directors from the Cooperative Sector;

(e) Two (2) directors from the Municipal ~~Utilities~~Utility Sector;

(f) One (1) director from the Federal Power Marketing ~~Agencies~~Agency Sector; and

(g) Two (2) directors from the Canadian ~~Utilities~~Utility Sector provided that both directors are not residents of the same Canadian province.

In addition, the board shall nominate two (2) directors from one or two Industry Sectors to be elected by the Members as a Regional Director.

Provided, however, that in choosing directors from an Industry Sector, there shall not be more directors from a particular Industry Sector than there are actual Members of such Industry Sector.

Members shall endeavor to select directors from Industry Sectors among individuals holding senior management or officer positions in Member organizations, and with a view toward ensuring geographic representation of the Corporate Region on the board. ~~-~~No two directors elected from Industry Sectors may be employees of a single Member or employees of Members that are affiliates. ~~-~~To the extent the Members of an Industry Sector do not select a director, that director position shall remain vacant until a director is selected by the Industry Sector.

~~Two (2~~Four (4) board members shall be Independent Directors nominated by the board of directors and elected by the Members. Independent Directors shall have relevant senior management expertise and experience to the reliable operation of the Bbulk Ppower Ssystem in North America.

Section 7.4 **Terms of Directors.** All directors will serve three-year, staggered terms ending on December 31. The initial term of newly elected Independent Directors and Regional Directors may be less than three years if the initial term begins at a time other than January 1. ~~except the initial term for one of the independent directors shall be two (2) years. .~~ Any director elected by an Industry Sector may be removed at any time by the affirmative vote of two-thirds (2/3) of the Members of the Industry Sector selecting such director. Regional Directors may be removed at any time by the affirmative vote of two-thirds (2/3) of the Members. An Independent Director may be removed by the affirmative vote of two-thirds (2/3) of the remaining directors.

Any director may be removed by the board of directors for non-attendance of three consecutive board meetings.

Section 7.5 Compensation and Reimbursement. All directors shall have the right to reimbursement by the Corporation of their actual reasonable travel expenses to board meetings or when specifically selected to represent the Corporation at a business meeting. The board of directors may set reasonable compensation for the service provided by Independent Directors; directors elected by an Industry Sectorfrom a Member shall not receive compensation.

Section 7.6 Vacancies. If a director resigns, dies, changes corporate affiliation or is removed during the term of office for which elected, the directorship shall thereupon be vacant and shall be filled as soon as practicable and in accordance with the same procedures that the directorship had previously been filled. The successor director shall hold office for the unexpired portion of the term of the director replaced.

Section 7.7 Meetings; Notice. An annual meeting of the board of directors shall be held without notice immediately following the annual meeting of the Members to elect the chair and vice chair of the board of directors for the next year. In addition, regular meetings may be held at such time or times as fixed by the board of directors. Schedules of regular meetings of the board of directors shall be published by the secretary and provided to the Membership. Special meetings of the board of directors may be called by the president or by three directors and shall be held at the principal office of the Corporation, or such other place within the Corporate Region as determined by the president after consultation with the board. Notice of the date, time, and place of a special meeting shall be given by the secretary not less than seven (7) days prior to the meeting by mail, telegram, or electronic communication to each director and the Membership. Except as necessary to discuss personnel issues, litigation or similar sensitive or confidential matters, all meetings of the board of directors shall be open to the Membership and other interested persons.

Section 7.8 Quorum. A majority of the directors currently holding office is a quorum for the transaction of business.

Section 7.9 Board Action. The act of a majority of the directors present at a meeting at which a quorum is present shall be the act of the board of directors, unless the act of a greater number is required by law or these Bylaws, however, in no event will an action of the dDirectors be valid where the action was passed solely by the vote of dDirectors from two Industry Sectors or defeated solely by the vote of dDirectors in a single Industry Sector.

Section 7.10 Action Without a Meeting. An action required or permitted to be taken at a board of directors meeting may be taken by written action, including electronic communication, signed by all of the directors of the Corporation. The written action is effective when signed by the required number of directors, unless a different effective time is provided in the written action.

Section 7.11 Action by Electronic Communication. A conference among directors by a means of communication through which the directors may simultaneously hear each other during the conference is a board meeting if the same notice is given of the conference as would be required

for a meeting and if the number of directors participating in the conference is a quorum. Participation in a meeting by this means constitutes personal presence at the meeting. A director may participate in a board meeting by any means of communication through which the director, other directors participating, and all directors physically present at the meeting may simultaneously communicate with each other during the meeting.

ARTICLE 8
ORGANIZATIONAL GROUPS

Section 8.1 Establishment of Organizational Groups. The board of directors shall establish such organizational groups, consisting of committees, sub-committees, task forces and working groups of Members, as are necessary and appropriate to accomplish the purposes of the Corporation in an efficient and cost-effective manner. All organizational groups shall be subject to the direction and control of the board. The membership of organizational groups shall be determined based upon experience, expertise and geographic diversity and to the extent practicable shall include balanced representation of the Industry Sectors.

The board of directors shall establish policies and procedures governing the creation of organizational groups, how they are populated, how voting and related matters are conducted and how they may be reorganized. The board shall conduct a review of all organizational groups of the Corporation on a periodic basis to ensure that the business of the Corporation is conducted in an efficient, cost-effective manner and shall include a statement of its conclusions and resulting actions in the board's report to Members at the annual meeting.

Section 8.2 Reimbursement. Consistent with the annual budget of the Corporation, the bBoard may authorize reimbursement by the Corporation for members of organizational groups (other than committees of the whole) of reasonable travel, meals and lodging expenses for organizational group meetings or for representation of the Corporation at other business meetings as authorized by the board. The board of directors may authorize reimbursement for persons acting on behalf of the Corporation, as necessary in the interests of the Corporation.

ARTICLE 9
OFFICERS

Section 9.1 Officers. The officers of the Corporation shall include a president, a secretary, a treasurer and any other officers as may be elected or appointed in accordance with the provisions of this Article. The board of directors may elect or appoint any additional officers that it deems desirable, such other officers to have the authority and perform the duties prescribed by the board of directors. The same individual may hold any number of offices, except that of president.

Section 9.2 Election and Term of Office. The officers of the Corporation shall be elected by the board of directors. Each officer shall hold office at the pleasure of the board. New officers may be created and the positions filled at any meeting of the board of directors. Each elected officer shall hold office until his or her successor has been duly elected and qualified.

Section 9.3 **Removal.** Any officer elected by the board of directors may be removed by the affirmative vote of two-thirds (2/3) of the board of directors whenever in its judgment the best interests of the Corporation would be served thereby, but such removal shall be without prejudice to the contract rights, if any, of the officer so removed. ~~-~~Election or appointment of an officer or agent shall not of itself create contract rights.

Section 9.4 **Vacancies.** A vacancy in any office because of death, resignation, removal, disqualification, or otherwise, may be filled by the board of directors for the unexpired portion of the term.

Section 9.5 **President.** The president shall be, in the discretion of the board of directors, either an employee of or contractor to the Corporation and shall:

(a) be the chief executive officer of the Corporation;

(b) sign certificates of M~~m~~membership, and may sign any deeds, mortgages, deeds of trust, notes, bonds, contracts or other instruments authorized by the board of directors to be executed, except in cases in which the signing and execution thereof shall be expressly delegated by the board of directors or by these Bylaws to some other officer or agent of the Corporation; and

(c) perform all duties incident to the office of president and chief executive officer, including hiring and directing staff, and such other duties as may be prescribed by the board of directors from time to time.

Section 9.6 **Secretary.** The secretary shall ensure that the following duties are carried out:

(a) the minutes of the meetings of the Members and of the board of directors are recorded;

(b) all required notices are duly given in accordance with these Bylaws and as required by law;

(c) a register of the current names and addresses of the Membership is maintained;

(d) a complete copy of the Articles of Incorporation and Bylaws of the Corporation containing all amendments thereto are kept on file at all times, which copies shall always be open to the inspection of the Membership; and

(e) generally perform all duties incident to the office of secretary and such other duties as may be prescribed by the board of directors from time to time.

Section 9.7 **Treasurer.** The treasurer shall be responsible for the following activities:

(a) maintain custody of all funds and securities of the Corporation;

(b) receipt of and the issuance of receipts for all monies due and payable to the Corporation and for deposit of all such monies in the name of the Corporation in such bank or banks or financial institutions as shall be selected by the board of directors; and

(c) generally perform all duties incident to the office of treasurer and such other duties as may be prescribed by the board of directors from time to time.

ARTICLE 10
CERTIFICATES OF MEMBERSHIP

Section 10.1 Certificates of Membership. The board of directors may provide for the issuance of certificates evidencing Membership in the Corporation, which certificates shall be in such form as may be determined by the board.

ARTICLE 11
BOOKS AND RECORDS

Section 11.1 Books and Records; Financial Statements. The Corporation shall keep at its registered office correct and complete copies of its Articles of Incorporation and Bylaws, accounting records, and minutes of meetings of Members, board of directors, and committees having any of the authority of the board of directors. A Member or Adjunct Member, or the agent or attorney of a Member or Adjunct Member, may inspect all books and records and voting agreements for any proper purpose at any reasonable time. Upon request, the Corporation shall give the Member or Adjunct Member a statement showing the financial result of all operations and transactions affecting income and surplus during its last annual accounting period and a balance sheet containing a summary of its assets and liabilities as of the closing date of the accounting period.

ARTICLE 12
FISCAL YEAR

Section 12.1 Fiscal Year. The fiscal year of the Corporation shall be the calendar year.

ARTICLE 13
TRANSFER OF ASSETS

Section 13.1 Member Approval Not Required. Subject to the restrictions set forth in the Certificate of Incorporation, the Corporation, by affirmative vote of the board of directors, may sell, lease, transfer, or dispose of its property and assets in the usual and regular course of its activities and grant a security interest in all or substantially all of its property and assets in the usual and regular course of its activities, upon those terms and conditions and for those considerations, which may be money, securities, or other instruments for the payment of money

or other property, as the board of directors considers expedient, in which case no Member approval is required.

Section 13.2 Member Approval; When Required. Subject to the restrictions set forth in the Certificate of Incorporation, the Corporation may sell, lease, transfer, or dispose of all or substantially all of its property and assets, including its good will, not in the usual and regular course of its activities, upon those terms and conditions and for those considerations, which may be money, securities, or other instruments for the payment of money or other property, as the board of directors considers expedient only when approved at a regular or special meeting of the Members by the affirmative vote of two-thirds (2/3) of all the Members. Notice of the meeting must be given to the Membership. The notice must state that a purpose of the meeting is to consider the sale, lease, transfer, or other disposition of all or substantially all of the property and assets of the Corporation.

ARTICLE 14
CONTRACTS, CHECKS, DEPOSITS, AND GIFTS

Section 14.1 Contracts. The board of directors may authorize any officer or officers or agent or agents of the Corporation, in addition to the officers so authorized by these Bylaws, to enter into any contract or execute and deliver any instrument in the name of and on behalf of the Corporation, and such authority may be general or may be confined to specific instances.

Section 14.2 Checks, Drafts, or Orders. All checks, drafts, or orders for the payment of money, notes, or other evidences of indebtedness issued in the name of the Corporation, shall be signed by such officer or officers or agent or agents of the Corporation, and in such manner as shall from time to time be determined by resolution of the board of directors.

Section 14.3 Deposits. All funds of the Corporation shall be deposited to the credit of the Corporation in such banks, trust companies, or other depositories as the board of directors may select.

Section 14.4 Gifts. The board of directors may accept on behalf of the Corporation any contribution, gift, bequest, or devise for any purpose of the Corporation.

ARTICLE 15
INSURANCE, LIABILITY, AND INDEMNIFICATION

Section 15.1 Insurance. The president is authorized to procure insurance to protect the Corporation against damages arising out of or related to any directive, order, procedure, action or requirement of the Corporation.

Section 15.2 Limitations on Liability. No director, officer, agent, employee, or other representative of the Corporation, and no corporation or other business organization that employs a director of the Corporation, or any director, officer, agent or employee of such corporation or other business organization, shall be personally liable to the Corporation or any Member or

Adjunct Member of the Corporation for any act or omission on the part of any such director, officer, agent, employee, or other representative of the Corporation, which was performed or omitted in good faith in his official capacity as a director, officer, agent, employee, or other representative of the Corporation. However, this release of liability shall not operate to release such a director, officer, agent, employee or other representative of the Corporation from any personal liability resulting from willful acts or omissions knowingly or intentionally committed or omitted by him in breach of these Bylaws for improper personal benefit or in bad faith.

Section 15.3 Indemnification. It is the intent of the Corporation to indemnify its directors, officers, agents, employees, or other representatives to the maximum extent allowed by law consistent with these Bylaws. Each director, officer, agent, employee, or other representative of the Corporation shall be indemnified by the Corporation against all judgments, penalties, fines, settlements, and reasonable expenses, including legal fees, incurred by him as a result of, or in connection with, any threatened, pending or completed civil, criminal, administrative, or investigative proceedings to which he may be made a party by reason of his acting or having acted in his official capacity as a director, officer, agent, employee, or representative of the Corporation, or in any other capacity which he may hold at the request of the Corporation, as its representative in any other organization, subject to the following conditions:

(a) Such director, officer, agent, employee, or other representative must have conducted himself in good faith and, in the case of criminal proceedings, he must have had no reasonable cause to believe that his conduct was unlawful. When acting in his official capacity, he must have reasonably believed that his conduct was in the best interests of the Corporation, and, when acting in any other capacity, he must have reasonably believed that his conduct was at least not opposed to the best interests of the Corporation.

(b) If the proceeding was brought by or on behalf of the Corporation, however, indemnification shall be made only with respect to reasonable expenses referenced above. No indemnification of any kind shall be made in any such proceeding in which the director, officer, agent, employee, or other representative shall have been adjudged liable to the Corporation.

(c) In no event, however, will indemnification be made with respect to any described proceeding ~~which~~ that charges or alleges improper personal benefit to a director, officer, agent, employee, or other representative and where liability is imposed upon him on the basis of the receipt of such improper personal benefit.

(d) In order for any director, officer, agent, employee, or other representative to receive indemnification under this provision, he shall vigorously assert and pursue any and all defenses to those claims, charges, or proceedings covered hereby, which are reasonable and legally available and shall fully cooperate with the Corporation or any attorneys involved in the defense of any such claim, charges, or proceedings on behalf of the Corporation.

(e) No indemnification shall be made in any specific instance until it has been determined by the Corporation that indemnification is permissible in that specific case, under the standards set forth herein and that any expenses claimed or to be incurred are reasonable. These two (2) determinations shall be made by a majority vote of at least a quorum of the board consisting solely of directors who were not parties to the proceeding for which indemnification or reimbursement of expenses is claimed. If such a quorum cannot be obtained, a majority of at least a quorum of the full board, including directors who are parties to said proceeding, shall designate a special legal counsel who shall make said determinations on behalf of the Corporation. In making any such determinations, the termination of any proceeding by judgment, order, settlement, conviction, or upon plea of nolo ~~contendre~~contendere, or its equivalent, shall not, in and of itself, be conclusive that the person did not meet the standards set forth herein.

(f) Any reasonable expenses, as shall be determined above, that have been incurred by a director, officer, agent, employee, or other representative who has been made a party to a proceeding as defined herein, may be paid or reimbursed in advance upon a majority vote of a quorum of the full board, including those who may be a party to the same proceeding. However, such director, officer, agent, employee, or other representative shall have provided the Corporation with (i) a written affirmation under oath that he, in good faith, believes that he has met the conditions for indemnification herein, and (ii) a written undertaking that he shall repay any amounts advanced, with interest accumulated at a reasonable rate, if it is ultimately determined that he has not met such conditions. In addition to the indemnification and reimbursement of expenses provided herein, the president shall purchase insurance that would protect the Corporation, its directors, officers, agents, employees, or other representatives against reasonably expected liabilities and expenses arising out of the performance of their duties for the Corporation.

ARTICLE 16
PARTICIPATION BY REGULATORY PARTICIPANTS

Section 16.1 Regulatory Participants. All Regulatory Participants shall be entitled to be Adjunct Members.

ARTICLE 17
PARTICIPATION BY FEDERAL POWER MARKETING ADMINISTRATIONS

Section 17.1 Power Marketing Administrations Participation. The participation by the United States through Federal power marketing administrations (PMA) in the Corporation is subject in all respects to acts of Congress and to regulations of the Secretary of Energy established thereunder. This reservation includes, but is not limited to, the statutory limitations upon the authority of the Secretary of Energy to submit disputes arising hereunder to arbitration. In the event of a conflict between this Article 17 and any other Article of these Bylaws, this Article 17 shall have precedence with respect to the application of these Bylaws to the United States.

Section 17.2 Failure of Congress to Make Appropriations. Where activities provided for herein extend beyond the current fiscal year, continued expenditures by the United States are contingent upon Congress making the necessary appropriations required for the continued performance of the obligations of the PMA hereunder. ~~-~~In case such appropriations are not made, the Corporation and its Members hereby release the PMA from its contractual obligations under these Bylaws and from all liability due to the failure of Congress to make such appropriation.

Section 17.3 Inapplicability of Bylaws to Congressional Members and Delegates. No member of, or delegate to, Congress shall be admitted to any share or part of, or to any benefit that may have arisen from, these Bylaws, but this restriction shall not be construed to extend to these Bylaws if made with a corporation or company for its general benefit.

Section 17.4 No Solicitation of Power Marketing Administration Participation. The Corporation and its Membership warrant that no Person or selling agency has been employed or retained to solicit or secure participation by a PMA in the Corporation upon an agreement or understanding for a commission, percentage, brokerage or contingent fee, excepting *bona fide* employees or *bona fide* established commercial or selling agencies maintained by the Membership for the purpose of securing business. ~~-~~For breach or violation of this warranty, a PMA shall have the right to annul its participation in the Corporation without liability or, in its discretion, to deduct from its dues or fees the full amount of such commission, percentage, brokerage, or contingent fee.

Section 17.5 Provisions Applicable to the Corporation. For the purpose of this Section 17.5 the term "Contract" shall mean these Bylaws and the term "Contractor" shall mean the Corporation. ~~–~~During the performance of this Contract, the Contractor agrees to the following provisions.

17.5.1.No Discrimination. Section 202 of the Executive Order No. 11246, 30 Fed. Reg. 12319 (1965), as amended by Executive Order No. 12086, 43 Fed. Reg. 46501 (1978), which provides, among other things, that the Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin, is incorporated by reference in the Contract.

17.5.2.Contract Work Hours and Safety Standards Act. The Contract, to the extent that it is of a character specified in Section 103 of the Contract Work Hours and Safety Standards Act, 40 U.S.C. § 329 (1986) (the "Act"), is subject to the provisions of the Act, 40 U.S.C. §§ 327-333 (1986), and to regulations promulgated by the Secretary of Labor pursuant to the Act.

17.5.3.Imprisonment. The Contractor agrees not to employ any person undergoing sentence of imprisonment in performing the Contract except as provided by 18 U.S.C. § 4082(c)(2) and Executive Order 11755, 39 Fed. Reg. 779 (1973).

ARTICLE 18
HEARINGS AND DISPUTE RESOLUTION

Section 18.1 Hearings. Except as otherwise provided in applicable agreements and/or law governing Membership in the Corporation, the Corporation shall be responsible for making final determinations regarding whether a r~~R~~egistered e~~E~~ntity has violated a Reliability Standard in accordance with the NERC Rules of Procedure.

Section 18.2 Disputes. Dispute resolution procedures will be established by the board of directors for disputes between Members, or between a Member and the Corporation, for issues arising under these Bylaws. ~~-~~Determinations related to violations of Reliability Standards will be resolved in accordance with the NERC Rules of Procedure. Except as otherwise provided in applicable agreements and/or law governing a Member's membership in the corporation.

ARTICLE 19
AMENDMENT OF BYLAWS

Section 19.1 Changes to the Bylaws. The power to adopt, amend, or repeal these Bylaws is vested in the Members as set forth in Section 6.5 of these Bylaws; provided however, upon the passage of any federal reliability legislation and/or the adoption of related requirements and procedures by NERC or any regulatory agency with jurisdiction, the board ~~or~~of directors shall have authority upon a two-thirds (2/3) vote to amend these Bylaws as necessary and appropriate to comply with such law and related requirements.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	**)** **)** **)**	**Docket No. AD18-7-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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May 9, 2018

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	**)** **)** **)**	**Docket No. AD18-7-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

On January 8, 2018, the Federal Energy Regulatory Commission (the "Commission") initiated a new proceeding to evaluate resilience of the bulk-power system ("BPS") in regions operated by regional transmission organizations and independent system operators (together, "RTOs").[1] Specifically, the Commission seeks to: (1) develop a common understanding of the term resilience; (2) understand how RTOs assess resilience; and (3) evaluate whether additional Commission action is appropriate.[2] While initially soliciting comments from RTOs, the Commission acknowledged that, "NERC and the regional entities tasked with implementation of mandatory reliability standards have a critical role to play in this area…. we will provide interested entities an opportunity to submit reply comments….."[3]

As the Commission certified Electric Reliability Organization ("ERO"),[4] the North American Electric Reliability Corporation ("NERC") must develop and enforce Reliability Standards that provide an adequate level of reliability for Reliable Operation of the BPS and must assess the reliability and adequacy of the BPS.[5] As discussed herein, resilience is a

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1 *Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,012 (2018) ("Order").

2 *Id.* at P 18.

3 *Id.* at P 19.

4 *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) ("Certification Order").

5 As defined in section 215 of the Federal Power Act ("FPA"). 16 USC 824o.

component of reliability in relation to an event and thus an implicit feature of NERC's activities. NERC hereby submits reply comments in this proceeding to summarize the manner in which resilience is a component of reliability, to highlight NERC Reliability Standards and other activities that support resilience, and to underscore the importance of reexamining resilience in light of the changing generation resource mix and evolving cyber and physical threats.[6]

I. COMMUNICATIONS

Notices and communications with respect to these comments may be addressed to the following:[7]

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[6] RTO comments were filed on March 9, 2018 by: Midcontinent Independent System Operator, Inc. ("MISO"), ISO New England Inc. ("ISO-NE"), Electric Reliability Council of Texas, Inc. ("ERCOT") and the Public Utility Commission of Texas ("PUCT"), Southwest Power Pool, Inc. ("SPP"), New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), and the California Independent System Operator Corporation ("CAISO").

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

II. EXECUTIVE SUMMARY

Reliability of the BPS requires the resilience to anticipate, withstand, recover, and adapt to events on the system. In accordance with section 215 of the FPA and Commission directive in the Certification Order, reliability encompasses aspects of resilience of the BPS. As discussed in these comments, NERC has defined the adequate level of reliability or "ALR" to include resilience as a time-based component of reliability. *See infra* Section III.A.

As recognized in RTO comments, NERC activities already address several aspects of resilience, including robustness, resourcefulness, rapid recovery, and adaptability of the grid. At the direction of the NERC Board of Trustees ("Board"), the Reliability Issues Steering Committee ("RISC") has also proposed a resilience framework to reexamine resilience and whether NERC should take additional action. The RISC resilience framework is based on the ALR and the National Infrastructure Advisory Council ("NIAC") Framework for Establishing Critical Infrastructure Goals (relied upon by the Commission for its proposed definition of resilience).[8] NERC will continue to assess whether further activities are appropriate to support a resilient grid, consistent with the overarching scope of ALR, the RISC resilience framework, and any applicable Commission orders. *See infra*, Section III.B.

NERC supports the Commission's renewed dialogue around resilience. The changing resource mix demands reevaluation of resilience and consideration of policies recognizing essential reliability services ("ERS") and the value of a balanced portfolio of generation and infrastructure that provide fuel assurance, particularly under extreme weather conditions. As detailed in prior NERC comments and reflected in RTO comments, the changing resource mix

[8] A Framework for Establishing Critical Infrastructure Resilience Goals, National Infrastructure Advisory Council (October 19, 2010), *available at*, https://www.dhs.gov/xlibrary/assets/niac/niac-a-framework-for-establishing-critical-infrastructure-resilience-goals-2010-10-19.pdf.

has implications for reliability. In addition, evolving cyber and physical threats aimed at critical energy infrastructure may challenge resilience in the future. These reliability implications support policies recognizing the value of ERS and a diverse energy portfolio with sufficient fuel assurance to promote resilience. Policies supporting ERS, fuel assurance, and security as key elements of resilience would help ensure that the BPS continues to evolve in a manner that supports Reliable Operation of a resilient grid. *See infra* Section III.C.

III. COMMENTS

A. Resilience is an Element of Reliable Operation of the BPS.

Pursuant to section 215 of the FPA, NERC develops Reliability Standards based on what is necessary to achieve an adequate level of reliability for Reliable Operation of the BPS.[9] NERC must also conduct Reliability Assessments that evaluate BPS performance and identify emerging risks to reliability. Reliable Operation of the BPS includes the ability to withstand probable contingencies and the ability to manage adverse reliability impacts of disturbances in a coordinated and controlled manner.[10] As a result, the Commission's order certifying NERC as the ERO, "direct[ed] NERC to consider and propose methods for ensuring that Reliability Standards provide for an adequate level of reliability and defin[e] 'an adequate level of

[9] 16 U.S.C. 824o(c)(1) (stating, "The Commission may certify one such ERO if the Commission determines that such ERO—(1) has the ability to develop and enforce, subject to subsection (e)(2) of this section, reliability standards that provide for an adequate level of reliability of the bulk-power system;"); *and* 16 U.S.C. 824o(a)(3)(providing, The term 'reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.").

[10] 16 USC 824o(a)(4) (stating, "The term 'reliable operation' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.").

reliability.'"[11] The Commission explained that, "unless NERC further explores what it means to provide an adequate level of reliability, targeting a valuable reliability goal may not be enough to prevent a Reliability Standard from reflecting the lowest common denominator…."[12]

Accordingly, NERC developed and filed a definition of the ALR to guide Reliability Standards development, Reliability Assessments, and technical committee work. In particular, NERC defines the ALR as the state that design, planning, and operation of the Bulk Electric System ("BES") will achieve when five performance objectives are met.[13] The ALR also lists two assessment objectives for purposes of assessing risks to reliability.[14] Each objective addresses Reliable Operation of the BES over four time frames: (1) steady state (the period before a disturbance and after restoration has achieved normal operating conditions); (2) transient (the transitional period after a disturbance and during high-speed automatic actions in response); (3) operations response (the period after the disturbance where some automatic actions occur and operators act to respond); and (4) recovery and system restoration (the time period after a widespread outage through initial restoration to a sustainable operating state and

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11 Certification Order, at P 240.

12 *Id.*

13 The ALR Performance Objectives are as follows (see ALR for detail):

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

14 The ALR Assessment Objectives are as follows (see ALR for detail):

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

recovery to a new steady state).[15] These periods of time correspond to the four outcome-based abilities of both the NIAC resilience framework and the Commission proposed definition of resilience: (1) robustness; (2) resourcefulness; (3) rapid recovery; and (4) adaptability.[16]

The ALR, NIAC framework, and Commission proposed definition of resilience demonstrate the manner in which resilience is an element of Reliable Operation over time in anticipation of and in response to an event. As NIAC states, "[i]nfrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."[17] NERC interprets the Commission's proposed definition of resilience as intended to include both shorter-term elements of resilience and longer-term adaptability, consistent with the NIAC framework and NERC-filed ALR. Hence, resilience pertains to reliability before, during, immediately after, and in the longer-term after an event. In this way, the ALR avoids the "lowest common denominator" concern that the Commission expressed in the Certification Order, avoids making electric consumers insurers of the BES, and allows for regional approaches tailored to regional risks. NERC filed the latest definition of the ALR on May 10, 2013, after notice, comment, and NERC Board approval.

B. NERC Reliability Standards, Reliability Assessments, Event Analysis, Situational Awareness, and Other Activities Address Resilience.

A BPS that provides an adequate level of reliability is a resilient one. By defining specific performance and assessment objectives for the BES that include elements of resilience,

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[15] *See*, "*Informational Filing on the Definition of Adequate Level of Reliability,*" Docket No. RR06-1-000 (filed May 10, 2013), *available at*, https://www.nerc.com/pa/Stand/Resources/Documents/Adequate_Level_of_Reliability_Definition_(Informational_Filing).pdf (including the definition of the ALR and supporting technical report).

[16] *See*, NIAC Framework, at p. 13.

[17] This definition is cited in a NERC report, "*Severe Impact Resilience: Considerations and Recommendations*" (May 9, 2012).

the NERC ALR supports a highly reliable and resilient grid. As expressed in the technical report attached to the ALR:

> ALR is an outcome of a multi-dimensional effort to identify Reliability Performance and Assessment Objectives and then achieve outcomes that will support reliable operations. This multi-dimensional effort is reflected in NERC's current and evolving body of reliability standards, which work together to establish a portfolio of performance outcomes, risk reduction, and capability-based reliability standards that are designed to achieve a defense in depth against an inadequate level of reliability. Other NERC programs, such as industry alerts, reliability assessments, event analysis, education, and the compliance with and enforcement of reliability standards, are designed to work in concert with reliability standards to support reliable operation. Each of these activities should be driven by the goal of consistently achieving an adequate level of reliability.

In accordance with this intent, NERC activities across the ERO Enterprise are driven towards supporting the ALR and a resilient system. As referenced in the RTO Comments,[18] these activities include, for example, Reliability Standards, GridEx, and Electric-Information Sharing Analysis Center ("E-ISAC") work. This section describes some of the ways in which NERC Reliability Standards, Reliability Assessments, Event Analysis, and other activities address resilience, while also highlighting the RISC resilience framework reexamining what is required for ALR and resilience in today's environment.

1. Reliability Standards.

As discussed in Section III.A above, NERC must develop Reliability Standards that provide for an adequate level of reliability for Reliable Operations of the BPS. Reliability Standards are defined to:

> include requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable

[18] *See, e.g.*, MISO Comments, at pp. 19, 21, 25, and 38; CAISO Comments, at pp. 7-8, 21-22, 26, 31, 41-42, and 113-119; PJM Comments, at pp. 4, 19-20, 30-31, 53-54, and pp. 72-73; ERCOT Comments, at pp. 3, 7, 18; SPP Comments, at pp. 5-8, 11, and 18-19; NYISO Comments, at pp. 5 and 25-27; and ISO-NE Comments, at pp. 16, 18, 40, 49-50, and 53-54. Please see RTO Comments for full discussion and further examples.

> operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.[19]

NERC Reliability Standards work together to establish a portfolio of performance-based outcome, risk reduction, and capability standards applicable to entities within NERC's jurisdiction and designed to support Reliable Operations.[20] As recognized in the RTO comments,[21] several Reliability Standards relate to the BPS's capability to withstand disturbances in anticipation of potential events, manage the system after an event, and/or prepare to restore or rebound after an event.

For example, NERC has developed the following:

- Reliability Standard TPL-001-4 (*Transmission System Planning Performance Requirements*): providing planning performance requirements in anticipation of potential events;
- Reliability Standard EOP-004-3 (*Event Reporting*): requiring that entities report disturbances and events threatening reliability;
- Reliability Standard EOP-005-2 (*System Restoration from Blackstart Resources*): including requirements pertaining to preparation for system restoration from Blackstart resources after an event;
- Reliability Standard EOP-006-2 (*System Restoration Coordination*): requiring that plans and personnel be prepared to support system restoration after an event;
- Reliability Standard EOP-011-1(*Emergency Operations*): requiring operating plans to mitigate emergencies;
- Reliability Standard CIP-008-5 (*Cyber Security - Incident Reporting and Response Planning*): requiring plans to address reportable cyber security incidents;

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[19] 16 USC §824o(a)(3).

[20] In response to CAISO's question regarding inverter-based resources, NERC clarifies that Reliability Standards apply to all resources within NERC jurisdiction.

[21] *See, e.g.*, MISO Comments, at pp. 19, 21, 25, and 38; CAISO Comments, at pp. 7-8, 21-22, 26, 31, 41-42, and 113-119; PJM Comments, at pp. 4, 19-20, 30-31, 53-54, and pp. 72-73; ERCOT Comments, at pp. 3, 7, 18; SPP Comments, at pp. 5-8, 11, and 18-19; NYISO Comments, at pp. 5 and 25-27; and ISO-NE Comments, at pp. 16, 18, 40, 49-50, and 53-54. *See also* the RTO Comments for full discussion and further examples.

- Reliability Standard CIP-014-2 (*Physical Security*): including physical security requirements; and

- Reliability Standard TPL-007-1 (*Transmission System Planned Performance for Geomagnetic Disturbance Events*): providing requirements related to geomagnetic disturbances.[22]

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

- Reliability Standard TPL-007-1 (*Transmission System Planned Performance for Geomagnetic Disturbance Events*): requiring corrective action plans if a geomagnetic disturbance vulnerability assessment concludes that the system does not meet certain performance requirements;

- Reliability Standard PRC-004-5 (*Protection System Misoperation Identification and Correction*): requiring a corrective action plan after Protection System Misoperations or declaration explaining why corrective action plans are beyond the entity's control or would not improve BES reliability;

- Reliability Standard PRC-006-3 (*Automatic Underfrequency Load Shedding*): requiring a corrective action plan where the automatic underfrequency load shedding ("UFLS") design assessment determines that the UFLS program does not meet certain performance characteristics; and

- Reliability Standard PRC-016-1 (*Remedial Action Scheme Misoperations*): requiring that responsible entities take corrective actions to avoid future remedial action scheme misoperations.[23]

These examples demonstrate how Reliability Standards support resilience, without requiring the construction of facilities or otherwise exceeding the scope of section 215 of the FPA.

2. Reliability Assessments.

In recognition of NERC's commitment to assess industry performance, analyze trends, and learn from performance successes and failures, NERC performs Reliability Assessments on potential risks to the BPS. This allows the ERO Enterprise to focus on and align activities in

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

[23] *Id.*

support of Reliable Operations of the BPS. NERC Reliability Assessments must evaluate the adequacy and operating reliability of the BPS. Resource adequacy reflects the ability of the system to supply electricity to meet consumer demand at all times.[24] Operating reliability is the ability of the system to withstand sudden disturbances to system stability or unanticipated loss of components.[25] Both of these concepts reflect an assessment of the resilience of the system as a whole.

The NERC Reliability Assessments program is in and of itself a component of resilience, as it serves as a credible source of information for policy makers and stakeholders. At a high level, Reliability Assessments evaluate the: 1) adequacy of resources to meet demand and energy requirements; 2) sufficiency of ERS; 3) capability of the transmission system to accommodate projected resources and demand; 4) vulnerabilities to fuel supply, transportation, and delivery; and 5) ability to manage extreme conditions. For example, NERC's Long-Term Reliability Assessment ("LTRA") provides an annual update of a ten-year outlook identifying key issues and reliability challenges facing the BPS. NERC Reliability Assessments serve as an independent resource and technical platform for important policy discussions.

In addition to NERC's annual Reliability Assessments, NERC conducts Special Reliability Assessments on topic-specific issues that require a closer examination. A recent example of this is NERC's 2017 *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System.*[26] The assessment was primarily prepared in response to the continuing trend of increasing reliance on natural gas capacity, as

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[24] October 2017 Filing, at Exhibit B, at p. 1 (stating, "NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects).

[25] *See supra* text accompanying note 17 (regarding NIAC's definition of resilience).

[26] *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System*, NERC (Nov. 2017), *available at*, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

highlighted in several of NERC's LTRAs and by the temporary closure of the Aliso Canyon natural gas storage facility in Southern California. Prior NERC assessments concluded that the growing interdependence of the natural gas and electric infrastructure resulted in new operational and planning reliability challenges that policy makers and industry should consider when making decisions. For example, the Aliso Canyon natural gas storage facility leak underscored not only the reliance on natural gas to meet electric demand, but also how the disruption of a single key natural gas infrastructure component can affect BPS reliability. The primary take-away of the 2017 assessment was that more planning studies are needed to inform policy makers, system planners, and market operators, and to support actions addressing the unique risks each system may have. ISO-NE's "Operational Fuel-Security Analysis," reviewing New England's unique reliability risks concerning increasing dependency on natural gas generation coupled with limited natural gas pipeline, fuel storage, and transportation options, provides a good example of how NERC assessments have contributed to further analysis of regional risks.[27]

The *State of Reliability 2017 Report* ("2017 SOR") provides additional detail on how NERC uses reliability indicators to tie the performance of the BES to the reliability performance objectives in the ALR. NERC's reliability indicators address risks to the BES, recovery after events, and ERS by examining, for example:

- Metric M-2: BPS Transmission-Related Events Resulting in Loss of Load;
- Metric M-4: Interconnection Frequency Response;
- Metric M-6: Average Percent Nonrecovery Disturbance Control Standard Events;
- Metric M-7: Disturbance Control Events Greater than Most Severe Single Contingency;

[27] ISO-NE Comments, at p. 1 (discussing the Operational Fuel-Security Analysis published Jan. 17, 2018).

- Metric M-8: Interconnected Reliability Operating Limit/System Operating Limit (IROL/SOL) Exceedances;
- Metric M-9: Correct Protection System Operations; and
- Metric M-11: Energy Emergency Alerts.[28]

As demonstrated by the 2017 SOR, NERC then evaluates performance in comparison to these reliability indicators to determine whether the BES meets the ALR and whether reliability is improving.

3. Event Analysis Program.

The NERC Event Analysis Program also serves an integral component of NERC's efforts in favor of resilience by supporting continuous improvement and learning from past events. In particular, Event Analysis provides insight and guidance by identifying and disseminating valuable information to owners, operators, and users of the BPS to enable improved and more reliable operations. Through this program, NERC evaluates BPS events by undertaking appropriate levels of analysis to determine the causes of the events, promptly assuring tracking of corrective actions designed to prevent recurrence, and providing lessons learned to the industry. NERC's August 2017 *Hurricane Harvey Event Analysis Report*, for example, provided analysis of Hurricane Harvey's impact on the BPS to ensure a complete, coherent, review and documentation of the event and restoration efforts.[29]

Event Analysis has augmented its activities to take into consideration issues affecting resilience under the changing resource mix. For example, in June 2017, the NERC Planning and Operating Committees created the Inverter-based Resource Performance Task Force ("IRPTF")

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[28] *See*, 2017 SOR, at Chapter 4 and Appendix E (providing a full list of reliability indicators and discussing conclusions for the 2017 SOR), *available at*, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.

[29] *August 2017 Hurricane Harvey Event Analysis Report*, NERC (Aug. 2017), *available at*, https://www.nerc.com/pa/rrm/ea/Pages/August-2017-Hurricane-Harvey-Event-Analysis-Report.aspx.

to consider some of the new challenges associated with the changing resource mix, specifically, the proliferation of inverter based resources. The task force is producing a guideline for inverter-based resource performance to support BPS reliability. While none of the inverter-based resource events examined to date meet the threshold of a NERC reportable event, NERC has continually reviewed and reported on the small occurrences, before they can become bigger events. In 2016, NERC issued the *1200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report* regarding the Blue Cut Fire in Southern California, detailing issues created by solar inverter settings and recommendations to help mitigate future interruptions. The October 2017 *Canyon 2 Fire Disturbance Report,* described the Canyon 2 Fire in the Southern California area, key findings regarding solar inverter issues, and recommendations thereafter to support reliable operation of the BPS. Further, in February 2018, NERC published the *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report.* The Event Analysis process provides valuable input for training and education, reliability trend analysis efforts, and Reliability Standards development, all of which support continued improvement of reliability. As a result, Event Analysis operates as one of the pillars of NERC's foundational activities in support of resilience.

NERC strives to develop a culture of reliability excellence that promotes and rewards aggressive self-critical review and analysis of operations, planning, and critical infrastructure protection processes. This helps avoid similar or repeated events through the timely identification and correction of event causes and the sharing of lessons learned. For example, based on analysis in the *1200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC recently issued recommendations for reliability through an Alert after NERC observed loss of solar resources during transmission disturbances due to the low-

voltage ride through setting of photovoltaic inverters.[30] Other NERC Alerts have addressed topics such as supply chain risk, threats targeting the electric industry and other critical sectors, vegetation management, and frequency response.[31] These Alerts demonstrate how Event Analysis contributes to resilience by focusing on the robustness of the grid, adaption to lessons learned, risks to reliability, and the changing resource mix.

4. Situational Awareness and Information Sharing Through the E-ISAC and NERC Bulk Power System Awareness.

NERC's activities as part of the E-ISAC and Bulk Power System Awareness ("BPSA") also contribute to resilience. A major disruption in electric service due to an event on the system, such as cyber-security incident or physical attack, could have far-reaching effects. As a result, the ERO Enterprise has instituted several initiatives to ensure a more resilient system, better secured against cyber and physical threats to the grid.

The E-ISAC serves as the primary security communications channel for the electricity industry and enhances industry readiness and ability to respond to threats, vulnerabilities, and incidents that could affect the BPS. The E-ISAC's Cybersecurity Risk Information Sharing Program ("CRISP") also provides a voluntary program to facilitate real-time, computer-to-computer data exchange involving potential security threats identified through monitoring participating utility networks. Further, the E-ISAC holds a biannual GridEx conference to allow participants the opportunity to self-assess their emergency response and recovery plans through simulated security exercises featuring stresses on the system.

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[30] *See, Loss of Solar Resources during Transmission Disturbances due to Inverter Settings*, NERC (June 20, 2017), *available at*, https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance.pdf.

[31] *See*, NERC Alerts, *available at*, https://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx.

Similarly, the NERC BPSA collects and analyzes information on system disturbances and other incidents that affect the North American BPS. The BPSA then disseminates this information to internal departments, registered entities, regional organizations, and governmental agencies as necessary. In addition, the BPSA monitors ongoing storms, natural disasters, and geopolitical events that may affect or are currently affecting the BPS. The BPSA issues alerts to NERC registered entities and the electricity sector upon discovering, identifying or receiving information that is critical to ensuring the reliability of the BPS. These activities by the E-ISAC and BPSA help support a BPS better able to anticipate, withstand, respond to, recover from, and learn from events.

5. The RISC Resilience Framework.

Building on the efforts summarized above, and as shown in the following table, the RISC identified a variety of ongoing NERC activities for resilience that correspond to the NIAC framework and Commission proposed definition of resilience. The elements of the RISC resilience framework are very similar to the NIAC framework with certain clarifications shown below in red. For example, the Critical Infrastructure Protection Committee suggested that NERC could improve the resilience framework by incorporating detection as an explicit aspect of resourcefulness. The RISC is examining whether further NERC action on resilience is appropriate. At the May 2018 Member Representatives Committee Meeting, the RISC will summarize its analysis and any recommendations for the NERC Board.

NIAC Resilience Constructs[32]	Key Programs and Activities	Specific Efforts\Tools
Robustness—The ability to continue operations in the face of disaster. In some cases, it translates into designing structures or systems to be strong enough to take a foreseeable punch. In others, robustness requires devising substitute or redundant systems that can be brought to bear should something important break or stop working. Robustness also entails investing in and maintaining elements of critical infrastructure so that they can withstand low probability but high consequence events.	• Reliability and Emerging Risk Assessments • Risk, Event and Performance Monitoring • Technical Committee work, including special projects • Mandatory Reliability Standards • Reliability Guidelines and technical reference documents • System Operator Certification and Credential Maintenance • System Operator Training • E-ISAC information sharing programs	• Alerts • State of Reliability Report o GADS o TADS o DADS o Protection system misoperations o TEAMS o FR Performance • Long-Term Reliability Assessment • Key Reliability Standards: o TPL (Extreme) o EOP o Blackstart Restoration o Personnel Credentials • GridEx • Security conferences and information sharing (e.g. GridSecCon) • Supply Chain Security • Security Practices
Resourcefulness—The ability to skillfully detect and manage a disaster as it unfolds. It includes identifying options, prioritizing what should be done both to control damage and to begin mitigating it, and communicating decisions to the people who will implement them. Resourcefulness depends primarily on people, not technology.	• Situational Awareness and Industry Coordination • Government Coordination • Cross-Sector Information Sharing • Mandatory Reliability Standards/Functional Model • Reliability Guidelines and technical reference documents • System Operator Certification and Credential Maintenance • System Operator Training	• BPSA information sharing tools and processes • E-ISAC information sharing tools and processes • Formation of a Crisis Action Team to support industry and governmental coordination • GridEx • Standards requirements o Reliability Coordinators o Transmission Operators o Communications
Rapid recovery—The capacity to get things back to normal as quickly as possible after a disaster in a coordinated and controlled manner. Carefully drafted contingency plans, competent emergency operations, and the means to get the right people and resources to the right places are crucial.	• Situational Awareness, Industry Coordination • Government Coordination • Cross-Sector Information Sharing • Reliability Guidelines and technical reference documents • System Operator Certification and Credential Maintenance • System Operator Training	• Support for Electric Sector Coordinating Council activities • BES simulation • System restoration coordination

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

C. The Commission Should Continue Policy Reform Recognizing Attributes of a Reliable and Resilient BPS.

As detailed in NERC's Comments in Docket No. RM18-1-000, the changing resource mix is altering the operational characteristics of the BPS.[33] This warrants reexamination of what is necessary to maintain a reliable system, including its resilience. NERC Reliability Assessments demonstrate that resilience depends on the operating characteristics of the evolving resource mix and the capability of such resources to provide ERS. The Event Analysis reports referenced above and Alert on solar inverter settings further illustrate how the changing resource mix may affect ERS. As highlighted in SPP's Comments, ERS (such as capacity, voltage support, system inertia, and frequency response) "supports resilience by virtue of unique characteristics and abilities to respond to a significant disturbance."[34] NERC supports continued Commission action, such as the recent primary frequency response order, recognizing the value

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

[33] *Comments of the North American Electric Reliability Corporation in Response to Grid Reliability and Resilience Pricing Notice of Proposed Rulemaking*, Docket No. RM18-1-000 (filed Oct.23, 2017) ("October 2017 Filing").

[34] SPP Comments, at p. 16.

of ERS and requiring integration of newly interconnecting resources in a manner that supports a reliable and resilient grid.[35]

In addition to ERS, fuel assurance and diversity are critical elements of a reliable and resilient system. A balanced portfolio of generation resources and transmission infrastructure ensures that the system has adequate capacity to meet consumer needs and is ready to respond to events.[36] As the resource mix changes, variable energy resources are expanding and the balancing resource often tends to be natural gas-fired generation. Natural gas-fired resources serve a key function in the generation fleet and depend upon a generally reliable fuel supply, for which fuel is transported on a "just-in-time" basis. Comments in this proceeding have underscored implications of this trend for reliability across regions.[37] NERC's October 2017 Filing also discussed how single source fuel dependency could have adverse impacts under common mode outages.[38] Recognizing that generating capacity alone does not guarantee dispatchable energy, it is also important to understand the difference in the potential outage rates of natural gas fired generating units with firm gas transportation compared to those units that lack firm transportation. As highlighted in NERC's 2014/2015 Winter Reliability Assessment, "increased reliance on gas-fired generation requires new approaches for assessing reliability."[39]

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35 *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, Order No. 842, 162 FERC ¶ 61,128 (2018).

36 October 2017 Filing, Exhibit B, at p. 1.

37 *See, e.g.*, MISO Comments, at pp. 23 and 37; CAISO Comments, at pp. 15 and 171; PJM Comments, at pp. 5-8 and 26; ERCOT Comments, at p. 19; ERCOT Comments, at p. 5; NYISO Comments at pp. 25 and 31; and ISO-NE Comments, at pp. 22 and 26. *See also* the RTO Comments for full discussion and further examples.

38 October 2017 Filing, at Exhibit B, at p. 1. Natural gas fuel dependency may be particularly concerning in areas where: (i) generators rely on interruptible gas pipeline transportation; (ii) natural gas interstate pipelines are constrained to meet demand beyond what has been contracted and committed; and (iii) there is greater reliance on natural gas-fired generation as a "primary" generation resource

39 2014–2015 Winter Reliability Assessment, at p. 8.

Without unduly favoring any generation resource or infrastructure, the Commission should consider policies that build upon its prior examination of natural gas – electric coordination.[40] For example, the Commission could encourage firm transportation, multiple pipeline connections, and dual-fuel capability as measures to reduce the risk of common-mode failure and wider-spread reliability challenges from fuel supply disruptions. Further, the Commission could consider requiring that resource adequacy assessments account for potential reliability ramifications associated with the "just-in-time" natural gas fuel delivery model. Finally, the Commission could consider whether it would be beneficial to pursue market rules that would provide assurances that generators will perform in normal and extreme circumstances. The RTO comments similarly highlighted mechanisms that could help or were already helping their region address potential risks associated with natural gas supply contingencies.[41] As NERC recommended in Docket No. RM18-1-000, the Commission should consider further policies acknowledging the value of reliability attributes provided by all resources, and require integration of new resources in a manner that supports a reliable electric grid, resilient in the face of events on the system.

[40] *See, e.g., Request for Comments of Commissioner Moeller on Coordination between the Natural Gas and Electricity Markets*, Docket No. AD12-12-000 (Feb. 3, 2012).

[41] *See, e.g.*, NYISO Comments, at pp. 31-32; ERCOT Comments, at p. 19; ISO Comments, at pp. 7 and 11-12; *and* PJM Comments, at pp. 5-8. Please see RTO Comments for full discussion and further examples.

IV. CONCLUSION

NERC appreciates the Commission's attention to resilience. As discussed above, resilience is an element of reliability in relation to an event. NERC has defined the adequate level of reliability to encompass aspects of resilience. In accordance with the ALR and section 215 of the FPA, NERC Reliability Standards, Reliability Assessments, Event Analysis, and other activities address resilience, even as the RISC continues examining whether further action is appropriate. NERC recommends that the Commission continue to pursue policies supporting reliability, including resilience.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service lists compiled by the Secretary in Docket No. AD18-7-000.

Dated at Washington, DC this 9th day of May 2018.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)**	**Docket Nos. RM12-1-000**
	)	**RM13-9-000**

INFORMATIONAL FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION REGARDING IMPLEMENTATION OF RELIABILITY STANDARD TPL-001-4 TABLE 1, FOOTNOTE 12

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March 30, 2018

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket Nos. RM12-1-000** **RM13-9-000**

INFORMATIONAL FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION REGARDING IMPLEMENTATION OF RELIABILITY STANDARD TPL-001-4 TABLE 1, FOOTNOTE 12

Pursuant to paragraph 30 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Order No. 786,[1] the North American Electric Reliability Corporation ("NERC")[2] hereby submits a report on the use of Reliability Standard TPL-001-4 Table 1, footnote 12. Footnote 12 permits the use of Non-Consequential Load Loss[3] as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment under certain conditions. In Order No. 786, the Commission approved Reliability Standard TPL-001-4 - Transmission System Planning Performance Requirements and directed NERC to, among other things, report on entity use of footnote 12. To address the Commission's directive, NERC submits a TPL-001-4 Table 1, footnote 12 Implementation Study attached hereto as **Attachment 1.**

[1] *Transmission Planning Reliability Standard*, Order No. 786, 145 FERC ¶ 61,051 (Oct. 17, 2013) ("Order No. 786").

[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] Unless otherwise designated, capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary of Terms"), *available at* https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[4]

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II. BACKGROUND

In Order No. 786, the Commission approved Reliability Standard TPL-001-4 - Transmission System Planning Performance Requirements.[5] The standard requires Planning Coordinators and Transmission Planners to perform planning assessments. Table 1 of the standard contains a series of planning events and describes system performance requirements for a range of potential system contingencies required to be evaluated by the planner. Footnote 12 and the referenced Attachment 1 provide specific parameters for the permissible use of planned Non-Consequential Load Loss to address Bulk Electric System performance issues. These parameters include:

- firm limitations on the maximum amount of load that an entity may plan to shed;
- safeguards to ensure against inconsistent results and arbitrary determinations that allow for the planned Non-Consequential Load Loss; and

[4] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2017), to allow the inclusion of more than two persons on the service list in this proceeding.

[5] Order No. 786 at P 1.

- a specifically defined, open and transparent, verifiable, and enforceable stakeholder process.

Reliability Standard TPL-001-4 was developed in response to Commission guidance and directives and was informed by the results of a data request analyzing the use of a previously enforceable version of the load loss footnote. In its petition for approval of TPL-001-4, NERC noted that it did not have data on the frequency of use of the new footnote 12 and, for that reason, committed to monitor use of footnote 12 and report the results of this monitoring following the first two years of the footnote's implementation.[6] Accordingly, in Order No. 786 the Commission directed NERC as follows:

> [T]he Commission directs NERC to report on the use of footnote 12 including the use and effectiveness of the local regulatory review and NERC review. This report is important because it will provide an analysis of the use of footnote 12, including but not limited to information on the duration, frequency and magnitude of planned non-consequential load loss, and typical (and if significant, atypical) scenarios where entities plan for non-consequential load loss. Further, the report will serve as a tool to evaluate the usefulness and effectiveness of local regulatory and ERO review, and identify whether MISO's concern [regarding the administrative burden of the footnote 12 process] or other issues arise that need to be addressed.[7]

Reliability Standard TPL-001-4 became effective in the United States on January 1, 2015. In accordance with the approved implementation plan, entities were required to comply with Requirements R1 and R7 pertaining to System models and establishing entity responsibilities as of that date. Entities were required to comply with the remaining standard Requirements R2 through R6 and R8 as of January 1, 2016.

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6 *See Petition of North American Electric Reliability Corporation for Approval of Modified Transmission Planning Reliability Standards in the Case of System Performance Following Loss of a Single Bulk Electric System Element*, Docket Nos. RM12-1-000 and RM13-9-000, at 11 (Feb. 28, 2013).

7 Order No. 786 at P 30.

III. REPORT ON IMPLEMENTATION OF FOOTNOTE 12

Beginning in 2017, NERC conducted a study to determine the frequency and circumstances surrounding use of Non-Consequential Load Loss as an Element of a Corrective Action Plan in the Near Term Transmission Planning Horizon of the Planning Assessment under the provisions of TPL-001-4 Table 1, footnote 12. To date, NERC has not received a request from an entity under the provisions of TPL-001-4, Attachment 1, Section 3 for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss. Therefore, NERC determined that it was necessary to survey Planning Coordinators and Transmission Planners to understand fully the extent of footnote 12 utilization, including use of footnote 12 in current and future planning years and at levels both above and below the threshold for ERO notification.

First, NERC sent a survey to all registered Planning Coordinators and Transmission Planners to identify those entities that have used, or planned to use, Non-Consequential Load Loss as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon in accordance with Reliability Standard TPL-001-4 Table 1, footnote 12 for the planning years 2016, 2017, or 2018. Based on the results of this survey, NERC conducted a more detailed follow-up survey to those entities who responded in the affirmative to the initial survey. NERC reviewed the information to determine which entities had used, or planned to use, Non-Consequential Load Loss in accordance with footnote 12 and summarized its findings in the attached report.

As described in more detail therein, the data indicates that use of planned Non-Consequential Load Loss in accordance with footnote 12 is rare among U.S.-based entities. Although the data set is limited, the available responses do suggest that Non-Consequential Load Loss is typically used only when alternative solutions, such as capital improvements, are in the

process of being implemented or are determined to be infeasible. NERC has not identified any issues regarding implementation of the stakeholder review process described in TPL-001-4 Attachment 1 at this time, although NERC notes that entity experience with these processes to date has been limited.

NERC expects to gain future insights into the implementation of TPL-001-4 Table 1, footnote 12 through the ERO Adverse Reliability Impact determination process identified in TPL-001-4 Attachment 1, as well as its through its compliance oversight activities. NERC also expects to gain additional information on the use of footnote 12 through the Reliability Assessment process and potentially though its committees. Such information would be used to further understand the frequency and circumstances surrounding the use of Non-Consequential Load Loss under footnote 12 as well as to inform future reviews of the TPL-001 standard.

IV. CONCLUSION

NERC respectfully requests that the Commission accept this filing in accordance with its directive from Order No. 786.

Respectfully submitted,

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March 30, 2018

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 30th day of March, 2018.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Study

Use of Non-Consequential Load Loss under Reliability Standard TPL-001-4 Table 1, footnote 12

March 30, 2018

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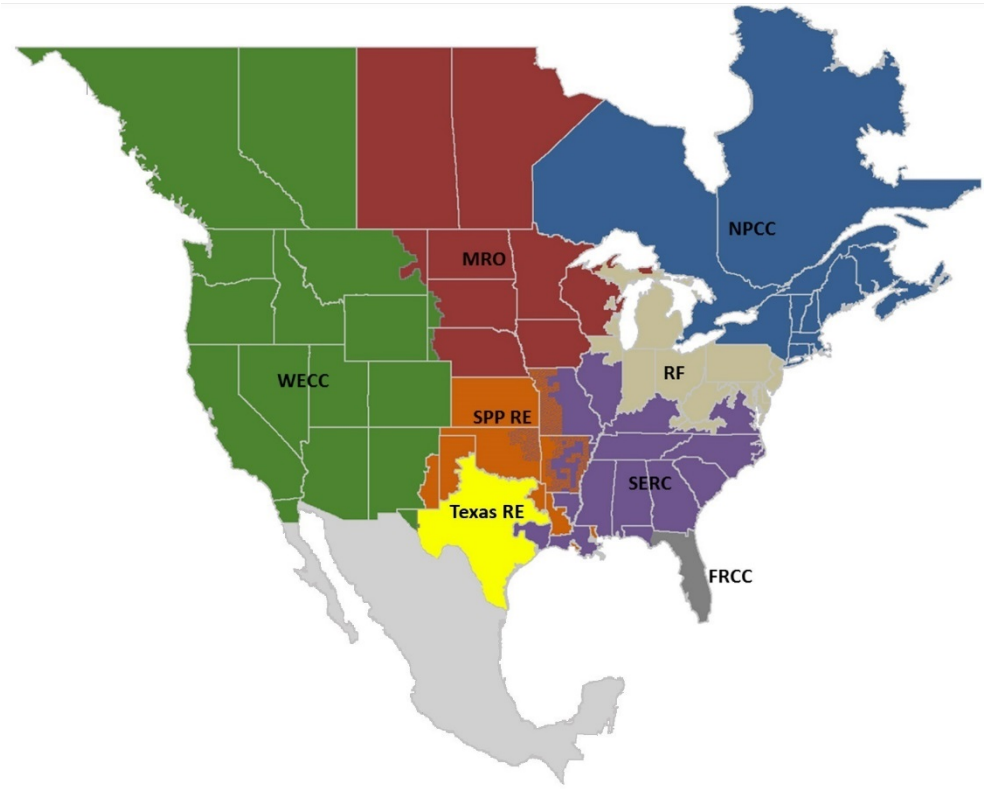
Preface

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

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



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

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE[1]	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

[1] Matters regarding the dissolution of the SPP RE are pending in Docket No. RR18-3-000.

Introduction

On October 17, 2013, the Federal Energy Regulatory Commission ("Commission" or "FERC") issued **Order No. 786,**[2] a final rule approving Reliability Standard TPL-001-4 (*Transmission System Planning Performance Requirements*). Reliability Standard TPL-001-4 requires Planning Coordinators and Transmission Planners to perform planning assessments. The purpose of the standard is to establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System ("BES") that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

Table 1 of TPL-001-4 contains a series of planning events and describes system performance requirements for a range of potential system contingencies the planner is required to evaluate. Footnote 12 of Table 1 provides parameters for the permissible use of planned Non-Consequential Load Loss to address BES performance issues. Specifically, the footnote provides:

> An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.[3]

Attachment 1 to the Standard provides that before the use of Non-Consequential Load Loss under Table 1, footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. Attachment 1 sets forth the requirements for this process, the type of information that must be documented, and the circumstances under which further action must be taken with applicable regulatory bodies and the Electric Reliability Organization.

In Order No. 786, the Commission directed NERC to report on the use of TPL-001-4 Table 1, footnote 12 as follows:

> [T]he Commission directs NERC to report on the use of footnote 12 including the use and effectiveness of the local regulatory review and NERC review. This report is important because it will provide an analysis of the use of footnote 12, including but not limited to information on the duration, frequency and magnitude of planned non-consequential load loss, and typical (and if significant, atypical) scenarios where entities plan for non-consequential load loss. Further, the report will serve as a tool to evaluate the usefulness and effectiveness of local regulatory and ERO review, and identify whether MISO's concern [*regarding the administrative burden of the footnote 12 process*] or other issues arise that need to be addressed.[4]

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2 *Transmission Planning Reliability Standard*, Order No. 786, 145 FERC ¶ 61,051 (Oct. 17, 2013) ("Order No. 786").

3 Reliability Standard TPL-001-4, *available at* http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf.

4 Order No. 786 at P 30.

Reliability Standard TPL-001-4 became effective in the United States on January 1, 2015. In accordance with the approved implementation plan, entities were required to comply with Requirements R1 and R7 pertaining to System models and establishing entity responsibilities as of that date. Entities were required to comply with the remaining standard Requirements R2 through R6 and R8 as of January 1, 2016.

TPL-001-4 Table 1, FN 12 Survey Methodology

In 2017, NERC conducted a study of Planning Coordinators and Transmission Planners to identify those entities that have used, or planned to use, Non-Consequential Load Loss as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon in accordance with Reliability Standard TPL-001-4 Table 1, footnote 12.

NERC sent an initial three-question survey to U.S. Transmission Planners and Planning Coordinators in February 2017. In September 2017, NERC sent a more detailed follow-up survey to those entities who responded in the affirmative to the initial survey.

NERC reviewed the information and documents provided, conducting additional follow-up through email and telephone communications as necessary. The information is summarized in this report.

Use of Non-Consequential Load Loss

In response to its 2017 survey, NERC received information on use of planned Non-Consequential Load Loss in accordance with TPL-001-4 Table 1, footnote 12 from approximately 200 United States registered entities identified by NERC Compliance Registry number (approximately 75% of all U.S.-based Transmission Planners and Planning Coordinators on the NERC Compliance Registry as of January 2018).

Of the total initial survey respondents, four registered entities indicated that they had used, or planned to use, Non-Consequential Load Loss in accordance with the provisions of Reliability Standard TPL-001-4 Table 1, footnote 12 in the 2016, 2017, or 2018 planning years. As this report focuses exclusively on the implementation and use of footnote 12, NERC excluded from this evaluation entities that indicated that they planned to use Non-Consequential Load Loss as permitted by Table 1 (see, e.g., for Planning Event P7) or in accordance with the 84 calendar month provision in Section A.5.

As of March 2018, NERC has not received any requests for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss under the provisions of TPL-001-4 Attachment 1, Section 3.[5]

Entity Survey regarding Use of Non-Consequential Load Loss under TPL-001-4 Table 1, Footnote 12

A summary of the responses provided by each registered entity that has indicated that it has used, or plans to use, Non-Consequential Load Loss in accordance with the provisions of Reliability Standard TPL-001-4 Table 1, footnote 12 is provided below.

MRO Entity 1

An entity in the Midwest Reliability Organization Region ("MRO Entity 1") reported that it intended to use Non-Consequential Load Loss as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon in accordance with TPL-001-4 Table 1, footnote 12 for the 2018 Planning Assessment.

MRO Entity 1 reported that, at this stage, it planned for a load loss of approximately 56 MW in that would effectively amount to a Category P3 contingency (UVLS operation on a 115 kV line with nearby generation offline). The type of load affected would consist of large rural residential and agricultural load. The MRO Entity estimated the event to be once every 11 to 12 years, based on historical performance, and the expected duration to be 30 minutes or less for residential and commercial customers. As an alternative to the planned Non-Consequential Load Loss, MRO Entity 1 considered building a second 115 kV line at a cost of approximately $20 million.

MRO Entity 1 reported that it had not yet begun the stakeholder and ERO review process set forth in TPL-001-4 Attachment 1, but it intended to initiate the stakeholder review process through its Independent System Operator later in 2018.

MRO Entity 2

A second entity in the MRO region ("MRO Entity 2") reported plans to use Non-Consequential Load Loss under TPL-001-4 footnote 12 during planning years 2016, 2017, and 2018. MRO Entity 2 placed an undervoltage load shedding (UVLS) scheme in service prior to the implementation of version 4 of TPL-001. The entity held stakeholder planning meetings to share information on the scheme and since its installation, no material changes have occurred. However,

[5] This section requires entities planning for Non-Consequential Load Loss meeting certain criteria to first ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service do not object to the use of Non-Consequential Load Loss under footnote 12, and to then seek a determination from the ERO of whether there are any Adverse Reliability Impacts caused by the request to use footnote 12 for Non-Consequential Load Loss.

MRO Entity 2 continues to provide updates to stakeholders on the UVLS through existing annual planning assessment processes, including status of future plans to alleviate the need for the existing UVLS.

MRO Entity 2's plans to use Non-Consequential Load Loss under footnote 12 impacts 31 MW during peak conditions. The types of customers affected include primarily residential and commercial customers, with some light industrial loads. Four subtransmission and distribution service providers are affected, impacting three registered entities.

SPP RE Entity

A cooperative entity in the Southwest Power Pool Regional Entity Region ("SPP RE Entity") reported that it intended to use Non-Consequential Load Loss as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon in accordance with TPL-001-4 Table 1, footnote 12 for the 2016, 2017, and 2018 Planning Assessments.

The SPP RE Entity reported that it planned for a load loss of less than 25 MW and involving two areas on the entity's system. One area experiences low voltage conditions that merit Non-Consequential Load Loss for a near-term summer peak loading conditions for multiple contingency simulations. Another area experiences near-term voltage violations in a high loading condition in all categories. Both areas have temporary operating guides along with operator actions in place while network upgrades are conducted.

The type of load affected would consist typically industrial customers, selected to have minimal impact on the health, safety, and welfare of the community. The SPP RE Entity estimated the expected duration of an outage to be from two to four hours, based on historical experience. SPP RE Entity reported that it only uses footnote 12 when other alternatives are not feasible, typically due to lead time on required network upgrades.

The SPP RE Entity reported that it notifies its affected members whenever a mitigation plan is filed that involves use of Non-Consequential Load Loss in accordance with TPL-001-4 Table 1, footnote 12 and would schedule formal meetings upon request. The SPP RE Entity has indicated that no disputes have occurred to date, although a dispute mechanism exists. SPP RE Entity coordinates with the SPP Planning Coordinator to ensure mitigation procedures will meet TPL Reliability Standards.

SERC Entity

An entity in the SERC Reliability Corporation region ("SERC Entity") reported that it is intending to use Non-Consequential Load Loss as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon in accordance with TPL-001-4 Table 1, footnote 12 for the first time in its upcoming Planning Assessment. The SERC Entity reported plans for a load loss of just below 25 MW through the summer of 2019 due to overloading a transmission line as a result of TPL-001-4 Table 1 contingency simulations. The voltage level of the Contingency is less than 300 kV.

The SERC Entity completed its stakeholder review process in late 2017. The type of load affected would consist of approximately 5,000 customers, including large residential and large commercial customers. Affected customers could include urgent care and assisted living facilities, as well as fire, police, and ambulance stations. Additionally, local traffic signals could be affected. No hospitals would be affected. Alternative remedies that were considered included automatically dropping load for the specific contingency at a cost of approximately $100,000, or upgrading the affected section of the transmission line, at a cost of approximately $6 million.

Since SERC Entity began tracking outages of this contingency in 2009, there has been one event lasting 52 seconds. If a similar event were to occur in the future, the assessed Non-Consequential Load would not be shed.

Conclusion

The responses from NERC's 2017 surveys indicate that use of Table 1, footnote 12 is rare among U.S.-based entities. Although the data set is limited, the available responses suggest that Non-Consequential Load Loss is typically used only when alternative solutions, such as capital improvements, are in the process of being implemented or are determined to be infeasible. NERC has not identified any issues regarding implementation of the stakeholder review process described in Attachment 1 at this time, although NERC notes that entity experience with these processes to date has been limited.

As of March 2018, NERC has not received any requests for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss under the provisions of TPL-001-4 Attachment 1, Section 3.

Going forward, NERC will continue to monitor the use of Non-Consequential Load Loss under Table 1, footnote 12 through its Compliance oversight activities and through the ERO review process contemplated by TPL-001-4 Attachment 1. Information on the implementation of footnote 12 may also come from other NERC activities and committees, such as the Reliability Assessment process and the Planning Committee. Such information would be used to understand the frequency and circumstances surrounding the use of footnote 12, including the efficiency and efficacy of the stakeholder and ERO review processes, and may inform future reviews of the TPL-001 Reliability Standard.

Appendices

Appendix A: Initial Survey

Appendix B: Follow-up Survey

Appendix A: Initial Survey

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Survey to Transmission Planners and Planning Coordinators on the use of TPL-001-4 Footnote 12

NERC is conducting this survey in preparing a report on how entities have used Reliability Standard TPL-001-4 Table 1, footnote 12 to plan for Non-Consequential Load Loss. NERC requests all Planning Coordinators and Transmission Planners to respond to the following three question survey by **June 30, 2017**. Responses should be sent to [NonConLoadLoss@nerc.net].

Background

On October 17, 2013, the Federal Energy Regulatory Commission ("Commission" or "FERC") issued **Order No. 786,** a final rule approving Reliability Standard TPL-001-4 (*Transmission System Planning Performance Requirements*), which requires Planning Coordinators and Transmission Planners to perform planning assessments. The purpose of TPL-001-4 is to "establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies."

Table 1 of TPL-001-4 contains a series of planning events and describes system performance requirements for a range of potential system contingencies the planner is required to evaluate. Footnote 12 of Table 1 provides parameters for the permissible use of planned Non-Consequential Load Loss to address BES performance issues. Attachment 1 to the Standard provides that before the use of Non-Consequential Load Loss under Table 1 footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process.

In Order No. 786, the Commission directed NERC to report on the use of TPL-001-4 Table 1, footnote 12. In accordance with that directive, NERC is preparing a report on how entities have used TPL-001-4 footnote 12 to plan for Non-Consequential Load Loss. To inform NERC's report, please answer the following survey:

Survey on the use of TPL-001-4 FN 12

Please provide your entity's information below:

Entity Name:

NCR:

Region(s) where registered:

Survey Completed by/Contact Info:

Registration: ◯Planning Coordinator ◯Transmission Planner

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Please respond to the following three questions by **June 30, 2017**:

1. Did your entity use non-Consequential Load Loss as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon in its annual Planning Assessment for 2016?

   ○ Yes
   ○ No

2. Did your entity use (or is your entity planning to use) non-Consequential Load Loss as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon in its annual Planning Assessment for 2017?

   ○ Yes
   ○ No
   ○ Unknown / To Be Determined (Provide Explanation Below)

3. Does your entity plan to utilize non-Consequential Load Loss as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon in its next annual Planning Assessment?
   ○ Yes
   ○ No
   ○ Unknown / To Be Determined (Provide Explanation Below)

If you answered YES to any of the questions above, NERC will send out a follow-up survey asking for additional information on your entity's use of footnote 12, including your experience with stakeholder and local regulatory review processes. Please indicate who NERC should contact with this follow up survey:

Name:
Address:
Title/Department:
Email:
Phone:

Thank you for your participation. Please direct any questions regarding this survey to [Ganesh.Velummylum@nerc.net].

Appendix B: Follow-up Survey

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Follow-up Survey to Transmission Planners and Planning Coordinators on the use of TPL-001-4 Footnote 12

NERC is sending this **follow-up survey** to Planning Coordinators and Transmission Planners who have previously responded that they have used, or plan to use, non-Consequential Load Loss as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon in accordance with Reliability Standard TPL-001-4 Table 1, footnote 12. NERC requests that receiving entities respond to this survey by **November 17, 2017**. Responses should be sent to [NonConLoadLoss@nerc.net].

Background

On October 17, 2013, the Federal Energy Regulatory Commission ("Commission" or "FERC") issued **Order No. 786,** a final rule approving Reliability Standard TPL-001-4 (*Transmission System Planning Performance Requirements*), which requires Planning Coordinators and Transmission Planners to perform planning assessments. The purpose of TPL-001-4 is to "establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies."

Table 1 of TPL-001-4 contains a series of planning events and describes system performance requirements for a range of potential system contingencies the planner is required to evaluate. Footnote 12 of Table 1 provides parameters for the permissible use of planned Non-Consequential Load Loss to address BES performance issues. Attachment 1 to the Standard provides that before the use of Non-Consequential Load Loss under Table 1 footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process.

In Order No. 786, the Commission directed NERC to report on the use of TPL-001-4 Table 1, footnote 12. In accordance with that directive, NERC is preparing a report on how entities have used TPL-001-4 footnote 12 to plan for Non-Consequential Load Loss. NERC previously issued a three-question survey intended to identify those entities that have used, or planned to use, non-Consequential Load Loss. This survey is directed to those entities that have responded in the affirmative to any of the questions on that survey.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Survey on the use of TPL-001-4 FN 12

Please provide your entity's information below:

Entity Name:

NCR:

Region(s) where registered:

Registration: ☐ Planning Coordinator ☐ Transmission Planner

Survey Completed by:

Name:

Address:

Title/Department:

Email:

Phone:

Identify the annual Planning Assessment years for which your entity used, or plans to use, non-Consequential Load Loss as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon in its annual Planning Assessment (*check all that apply*):

- ☐ 2016
- ☐ 2017
- ☐ 2018

Please answer the following questions for each of the annual Planning Assessments in which your entity used, or is planning to use, non-Consequential Load Loss as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon.

Annual Planning Assessment for Year:

Question 1: TPL-001-4 Attachment 1: Stakeholder Process
Reliability Standard TPL-001-4 Attachment 1 Section I provides that the Transmission Planner or Planning Coordinator planning to use non-Consequential Load Loss under footnote 12 shall ensure that the utilization is reviewed through an open and transparent stakeholder process. Section I also provides that an entity does not have to repeat the stakeholder process unless conditions have materially changed for a subsequent application.

1A: Is this instance the first time the entity has used or planned to use non-Consequential Load Loss under Reliability Standard TPL-001-4 footnote 12?

- ◯ Yes
- ◯ No

1B: Did the entity ensure review, or is it in the process of ensuring review, of its planned use of footnote 12 under an open and transparent stakeholder process?

- ◯ Yes
- ◯ No/Explain

1C: Describe or provide a copy of the stakeholder process used to review use of footnote 12 and describe how the following five process requirements were met, or are being met, for this specific application:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues

2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period

3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants

4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns

5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

1C: Did the result of the stakeholder process result in any changes to your entity's planned use of non-Consequential Load Loss? Please describe.

Question 2: TPL-001-4 Attachment 1: Required Information
Reliability Standard TPL-001-4 Attachment 1 Section II requires the entity to make available certain documented information for the planned use of Non-Consequential Load Loss under footnote 12.

2A: For this specific application of planned non-Consequential Load Loss, describe, or provide copies of documentation provided to stakeholders that describe, the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level

    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency

2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance

4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance

5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12

6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12

7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12

8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

Question 3: TPL-001-4 Attachment 1: Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Reliability Standard TPL-001-4 Attachment 1 Section III provides that, in certain circumstances, Transmission Planners and Planning Coordinators must ensure that applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12. Provided there is no objection, documentation is to be submitted to the ERO for a determination of whether there are any Adverse Reliability Impacts.

3A: In this specific application, did the planned load loss meet either or both of the following two circumstances:

The voltage level of the Contingency is greater than 300 kV?

- ◯ Yes, Specify voltage level:
- ◯ No

The planned non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW?

- ◯ Yes, specify amount:
- ◯ No

3B. How did your entity ensure that the applicable regulatory authority or governing body responsible for retail electric service did not object to the use of Non-Consequential Loss under footnote 12?

3C. Describe your entity's experience with the local regulatory review process, including the time from initiation to completion. If the local regulator did object to the use of Non-Consequential Load Loss, or has not yet reached an opinion, please describe the circumstances and whether any changes were made to address that body's concerns.

3D. Has your entity submitted information to the ERO, or does it plan to submit information to the ERO, for a determination of whether there are any Adverse Reliability Impacts caused by the request to use footnote 12 for non-Consequential Load Loss?

- ◯ Yes/submitted on DATE
- ◯ Yes/plan to submit on approximately DATE
- ◯ No
- ◯ N/A

Additional Questions

If not addressed in response to the questions above:

4A: for which time period in the Near-Term Transmission Planning Horizon is the planned non-Consequential Load Loss being used?

4B: Is the use of footnote 12 caused by the addition or retirement of a system element, or does it reflect existing system topology?

5. Do you have any other comments that you wish to share with NERC regarding your entity's experience planning for non-Consequential Load Loss under footnote 12?

Thank you for your participation. Please direct any questions regarding this survey to [NonConLoadLoss@nerc.net].

20180530-3014 FERC PDF (Unofficial) 05/30/2018

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD18-2-000

May 30, 2018

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Shamai Elstein
Senior Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation and Western Electricity Coordinating Council for Approval of Proposed Regional Reliability Standard BAL-004-WECC-3

Dear Mr. Elstein:

On March 8, 2018, the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) filed a joint petition seeking approval of proposed regional Reliability Standard BAL-004-WECC-3 (Automatic Time Error Correction). NERC and WECC also requested approval of the associated effective date for the proposed regional Reliability Standard, violation risk factors and violation severity levels, as well as retirement of currently-effective regional Reliability Standard BAL-004-WECC-2. Proposed regional Reliability Standard BAL-004-WECC-3 seeks to maintain Interconnection frequency and to ensure that time error corrections and primary inadvertent interchange payback are effectively conducted in a manner that does not adversely affect the reliability of the Western Interconnection.[1]

NERC's filing was noticed on March 13, 2018, with interventions, comments and protests due on or before April 12, 2018. Southern California Edison filed a timely motion to intervene, raising no issues.

[1] Petition at 1.

20180530-3014 FERC PDF (Unofficial) 05/30/2018

NERC's uncontested filing is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2017), effective as of the date of this order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2017).

Sincerely,

David Ortiz, Acting Director
Office of Electric Reliability

20180530-3014 FERC PDF (Unofficial) 05/30/2018

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20180530-3015 FERC PDF (Unofficial) 05/30/2018

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD18-5-000

May 30, 2018

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Shamai Elstein
Senior Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation and Western Electricity Coordinating Council for Approval of Proposed Regional Reliability Standard FAC-501-WECC-2

Dear Mr. Elstein:

On March 16, 2018, the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) filed a joint petition seeking approval of proposed regional Reliability Standard FAC-501-WECC-2 (Transmission Maintenance). NERC and WECC also requested approval of the associated effective date for the proposed regional Reliability Standard, violation risk factors and violation severity levels, as well as retirement of currently-effective regional Reliability Standard FAC-501-WECC-1. Proposed regional Reliability Standard FAC-501-WECC-2 addresses transmission maintenance for specified transmission paths in the Western Interconnection.[1]

NERC's filing was noticed on March 27, 2018, with interventions, comments and protests due on or before April 26, 2018. Southern California Edison filed a timely motion to intervene, raising no issues.

NERC's uncontested filing is hereby approved pursuant to the relevant authority

[1] Petition at 1.

20180530-3015 FERC PDF (Unofficial) 05/30/2018

delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2017), effective as of the date of this order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2017).

Sincerely,

David Ortiz, Acting Director
Office of Electric Reliability

Document Content(s)

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FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD18-4-000

May 2, 2018

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: S. Shamai Elstein
Senior Counsel for North American Electric Reliability Corporation

Reference: Petition for Approval of Proposed Reliability Standard PRC-025-2

Dear Mr. Elstein:

On March 16, 2018, the North American Electric Reliability Corporation (NERC) filed a petition seeking approval of proposed Reliability Standard PRC-025-2 (Generator Relay Loadability), the associated implementation plan, and violation risk factors and violation severity levels.[1]

NERC states that proposed Reliability Standard PRC-025-2 enhances currently-effective Reliability Standard PRC-025-1 by better addressing the risk of unnecessary generator tripping when voltage is depressed and the generator is capable of increased reactive power output and voltage support during the voltage disturbance.[2]

NERC's filing was noticed on March 20, 2018, with comments, interventions and protests due on or before April 19, 2018. Southern California Edison filed a timely motion to intervene, raising no issues.

NERC's uncontested filing is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2017), effective as of the date of this order.

[1] NERC Petition at 1.

[2] NERC Petition at 2-3.

20180502-3031 FERC PDF (Unofficial) 05/02/2018

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2017).

Sincerely,

David Ortiz, Acting Director
Office of Electric Reliability

Document Content(s)

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FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
North American Electric Reliability
Corporation
Docket No. RR18-2-000

March 31, 2018

North American Electric Reliability Corporation
1325 G Street, NW, Suite 600
Washington, DC 20005

Attention: Lauren A. Perotti
Counsel for North American Electric Reliability Corporation

Reference: Revised SERC Reliability Corporation Regional Reliability Standard Development Procedure

Dear Ms. Perotti:

On February 12, 2018, North American Electric Reliability Corporation (NERC) submitted proposed revisions to the SERC Reliability Corporation (SERC) regional reliability standards development procedure (RSDP). NERC states that the proposed revisions (1) account for revisions to the NERC-SERC Delegation Agreement effective January 1, 2016; (2) align the SERC RSDP with NERC documents; (3) revise certain committee titles and process roles to reflect the current SERC committee and organization structure; (4) add a Roles and Responsibilities chart; (5) add an Errata section to provide a procedure for correcting errors discovered in approved regional standards; and (6) provide non-substantive revisions to improve language and format.

Notice of this filing was issued on February 27, 2018, with protests and interventions due on or before March 5, 2018. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.214. No adverse comments were received.

NERC's uncontested filing is accepted pursuant to the relevant authority delegated to the Director, Office of Energy Market Regulation, under 18 C.F.R. § 375.307, as of the date of this order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.307(a)(2)(vi). This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents. Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order pursuant to 18 C.F.R. § 385.713.

Sincerely,

Penny S. Murrell

Penny S. Murrell, Director
Division of Electric Power Regulation – Central

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163 FERC ¶ 61,126

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM18-8-000]

Geomagnetic Disturbance Reliability Standard

(May 17, 2018)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to approve Reliability Standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events). The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, submitted proposed Reliability Standard TPL-007-2 for Commission approval. Geomagnetic disturbance events (GMDs) occur when the sun ejects charged particles that interact with and cause changes in the earth's magnetic fields. Proposed Reliability Standard TPL-007-2 modifies currently-effective Reliability Standard TPL-007-1 by requiring applicable entities to: conduct supplemental GMD vulnerability assessments and thermal impact assessments; obtain geomagnetically induced current and magnetometer data; and meet certain deadlines for the development and completion of tasks in corrective action plans. In addition, the Commission proposes to direct NERC to develop and submit modifications to the Reliability Standard to require applicable entities to develop and

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implement corrective action plans to mitigate supplemental GMD event vulnerabilities.

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

ADDRESSES: Comments, identified by docket number, may be filed electronically at http://www.ferc.gov in acceptable native applications and print-to-PDF, but not in scanned or picture format. For those unable to file electronically, comments may be filed by mail or hand-delivery to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426. The Comment Procedures Section of this document contains more detailed filing procedures.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

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163 FERC ¶ 61,126
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Geomagnetic Disturbance Reliability Standard Docket No. RM18-8-000

NOTICE OF PROPOSED RULEMAKING

(May 17, 2018)

1. Pursuant to section 215 of the Federal Power Act (FPA), the Commission proposes to approve Reliability Standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events).[1] The Commission also proposes to approve the associated violation risk factors and violation severity levels, implementation plan, and effective date for proposed Reliability Standard TPL-007-2. The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted proposed Reliability Standard TPL-007-2 for approval in response to a Commission directive in Order No. 830.[2] Geomagnetic disturbance events (GMDs) occur when the sun ejects charged particles that interact with and cause changes in the earth's magnetic fields. This interaction can cause

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

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

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geomagnetically induced currents (GICs) to flow in an electric power system and, depending on various factors affecting the intensity of the current, can result in a risk of voltage instability or voltage collapse, as well as equipment loss or failure.

2. Proposed Reliability Standard TPL-007-2 modifies currently-effective Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events) by requiring applicable entities to: (1) conduct supplemental GMD vulnerability assessments and thermal impact assessments; (2) obtain GIC and magnetometer data; and (3) meet certain deadlines for the development and completion of tasks in corrective action plans.

3. The Commission proposes to approve proposed Reliability Standard TPL-007-2 as it largely addresses (with one exception discussed below) the directives in Order No. 830 to modify currently-effective Reliability Standard TPL-007-1: (1) to revise the benchmark GMD event definition, as it pertains to the required GMD Vulnerability Assessments and transformer thermal impact assessments, so that the definition is not based solely on spatially-averaged data; (2) to require the collection of necessary GIC monitoring and magnetometer data; and (3) to include a one-year deadline for the completion of corrective action plans and two- and four-year deadlines to complete mitigation actions involving non-hardware and hardware mitigation, respectively.

4. While proposed Reliability Standard TPL-007-2 addresses the first directive in Order No. 830 by requiring applicable entities to conduct supplemental GMD vulnerability and thermal impact assessments, which do not rely solely upon on spatially-averaged data, the proposed Reliability Standard does not require applicable entities to

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mitigate vulnerabilities identified pursuant to such a supplemental assessment.[3] NERC's proposal to modify the benchmark, but then allow entities the discretion to take corrective action based solely on the results of the spatially-averaged data while taking under advisement ("an evaluation of possible actions") the results of the supplemental assessment, does not satisfy the clear intent of the Commission's directive. Moreover, Order No. 830 reiterated the directive in Order No. 779 that NERC develop a second stage GMD Reliability Standard requiring GMD vulnerability assessments and that "owners and operators [] develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System."[4] Accordingly, as discussed below, the Commission proposes to direct that NERC, pursuant to section 215(d)(5) of the FPA, develop and submit modifications to the Reliability Standard to require applicable entities to develop and implement corrective action plans to mitigate vulnerabilities revealed by conducting supplemental GMD vulnerability assessments.[5] The Commission proposes to direct NERC to submit the modified Reliability Standard for approval within 12 months from the effective date of Reliability Standard TPL-007-2.

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[3] *See* Order No. 830, 156 FERC ¶ 61,215 at P 44 (directing NERC to "develop revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data").

[4] Order No. 830, 156 FERC ¶ 61,215 at P 7.

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

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5. In addition, while proposed Reliability Standard TPL-007-2 imposes deadlines for the preparation and completion of tasks in corrective action plans, Requirement R7.4 of the proposed Reliability Standard also permits applicable entities to exceed deadlines for completing corrective action plan tasks when "situations beyond the control of the responsible entity [arise]." As discussed below, the Commission seeks comment on two options that it is considering regarding proposed Requirement R7.4. Under the first option, the Commission would, pursuant to section 215(d)(5) of the FPA, direct NERC to modify the Reliability Standard to bring the proposed standard into alignment with the Commission's direction in Order No. 830, through a process whereby NERC considers extensions on a case-by-case basis informed by proposed Requirement R7.4.[6] Under the second option, the Commission would approve proposed Requirement R7.4. Under both options, the Commission would direct NERC to prepare and submit a report regarding how often and why applicable entities are exceeding corrective action plan deadlines following implementation of the proposed Reliability Standard. Under such a directive, NERC would submit the report within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2.[7]

[6] Order No. 830, 156 FERC ¶ 61,215 at P 102.

[7] NERC's proposed implementation plan provides that, depending on the effective date of Reliability Standard TPL-007-2, applicable entities will be required to comply with the requirements of the proposed Reliability Standard on a staggered schedule. For example, if proposed Reliability Standard TPL-007-2 becomes effective before January 1, 2021, the last requirement applicable entities will be required to comply with *(continued ...)*

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I. Background

A. Section 215 and Mandatory Reliability Standards

6. Section 215 of the FPA requires the Commission to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Once approved, the Reliability Standards may be enforced in the United States by the ERO, subject to Commission oversight, or by the Commission independently.[8]

B. GMD Primer

7. GMD events occur when the sun ejects charged particles that interact and cause changes in the earth's magnetic fields.[9] Once a solar particle is ejected, it can take between 17 to 96 hours (depending on its energy level) to reach earth.[10] A geoelectric field is the electric potential (measured in volts per kilometer (V/km)) on the earth's surface and is directly related to the rate of change of the magnetic fields.[11] The geoelectric field has an amplitude and direction and acts as a voltage source that can

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is Requirement R7 54 months following the effective date of Reliability Standard TPL-007-2. If proposed Reliability Standard TPL-007-2 becomes effective after January 1, 2021, the last requirement applicable entities will be required to comply with is Requirement R8 72 months following the effective date of Reliability Standard TPL-007-2.

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

[9] *See* NERC, 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System at i-ii (February 2012), http://www.nerc.com/files/2012GMD.pdf.

[10] *Id.* at ii.

[11] *Id.*

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cause GICs to flow on long conductors, such as transmission lines.[12] The magnitude of the geoelectric field amplitude is impacted by local factors such as geomagnetic latitude and local earth conductivity.[13] Geomagnetic latitude is the proximity to earth's magnetic north and south poles, as opposed to earth's geographic poles.[14] Local earth conductivity is the ability of the earth's crust to conduct electricity at a certain location to depths of hundreds of kilometers down to the earth's mantle. Local earth conductivity impacts the magnitude (i.e., severity) of the geoelectric fields that are formed during a GMD event by, all else being equal, a lower earth conductivity resulting in higher geoelectric fields.[15]

8. GICs can flow in an electric power system with varying intensity depending on the various factors discussed above. As explained in the Background section of the proposed Reliability Standard, "[d]uring 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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[12] *Id.*

[13] NERC, Benchmark Geomagnetic Disturbance Event Description, Docket No. 15-11-000, at 4 (filed June 28, 2016) (2016 NERC White Paper).

[14] *Id.*

[15] *Id.*

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C. Currently-Effective Reliability Standard TPL-007-1 and Order No. 830

1. Currently-Effective Reliability Standard TPL-007-1

9. Reliability Standard TPL-007-1 consists of seven requirements and applies to planning coordinators, transmission planners, transmission owners and generation owners who own or whose planning coordinator area or transmission planning area includes a power transformer with a high side, wye-grounded winding connected at 200 kV or higher.

10. Requirement R1 requires planning coordinators and transmission planners (i.e., "responsible entities") to determine the individual and joint responsibilities in the planning coordinator's planning area for maintaining models and performing studies needed to complete the GMD vulnerability assessment required in Requirement R4. Requirement R2 requires responsible entities to maintain system models and GIC system models needed to complete the GMD vulnerability assessment required in Requirement R4. Requirement R3 requires each responsible entity to have criteria for acceptable system steady state voltage performance for its system during the GMD conditions described in Attachment 1 of Reliability Standard TPL-007-1. Requirement R4 requires responsible entities to conduct a GMD vulnerability assessment every 60 months using the benchmark GMD event described in Attachment 1. Requirement R5 requires responsible entities to provide GIC flow information, based on the benchmark GMD event definition, to be used in the transformer thermal impact assessments required in Requirement R6, to each transmission owner and generator owner that owns an applicable transformer within the applicable planning area. Requirement R6 requires

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transmission owners and generator owners to conduct thermal impact assessments on solely and jointly owned applicable transformers where the maximum effective GIC value provided in Requirement R5 is 75 amps per phase (A/phase) or greater. Requirement R7 requires responsible entities to develop corrective action plans if the GMD vulnerability assessment concludes that the system does not meet the performance requirements in Table 1 of Reliability Standard TPL-007-1.

11. Calculation of the benchmark GMD event, against which applicable entities must assess their facilities, is fundamental to compliance with Reliability Standard TPL-007-1. Reliability Standard TPL-007-1, Requirement R3 states that "[e]ach responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1."

Reliability Standard TPL-007-1, Attachment 1 states that the benchmark GMD event is composed of four elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) a scaling factor to account for local geomagnetic latitude; (3) a scaling factor to account for local earth conductivity; and (4) a reference geomagnetic field time series or wave shape to facilitate time-domain analysis of GMD impact on equipment. The product of the first three elements is referred to as the regional peak geoelectric field amplitude. The benchmark GMD event defines the geoelectric field values used to compute GIC

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flows for a GMD vulnerability assessment, which is required in Reliability Standard TPL-007-1.[16]

12. For the purpose of determining a benchmark event that specifies what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System, NERC determined that a 1-in-100 year GMD event would cause an 8 V/km reference peak geoelectric field amplitude at 60 degree north geomagnetic latitude using Québec's earth conductivity.[17] Scaling factors (i.e., multiplying values) are applied to this reference peak geoelectric field amplitude to adjust the 8 V/km value for different geomagnetic latitudes (scaling factors between 0.1 and 1.0) and earth conductivities (scaling factors between 0.21 and 1.17). NERC identified a reference geomagnetic field time series from an Ottawa, Ontario magnetic observatory during a 1989 GMD storm affecting Québec. NERC used this to estimate a time series (i.e., 10-second values over a period of days) of the geoelectric field that is representative of what is expected to occur at 60 degree geomagnetic latitude during a 1-in-100 year GMD event. Such a time series

[16] *See* Reliability Standard TPL-007-1, Requirements R4 and R5. Reliability Standard TPL-007-1 does not set a threshold amount of GIC flow that would constitute a vulnerable transformer. However, if a transformer is calculated to experience a maximum effective GIC flow during a benchmark GMD event of a least 75 A/phase, a thermal impact assessment of that transformer is required. *See* Reliability Standard TPL-007-1, Requirement R6.

[17] NERC used Québec as the location for the reference peak 1-in-100 year GMD event because of its proximity to 60 degree geomagnetic latitude and its well understood earth model. By creating scaling factors, each entity can scale this reference peak geoelectric field and geoelectric field time series values to match its own expected field conditions.

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is used in some methods of calculating the vulnerability of a transformer to damage from heating caused by GIC.

13. NERC used field measurements taken from the International Monitor for Auroral Geomagnetic Effects (IMAGE) magnetometer chain, which consists of 39 magnetometer stations in Northern Europe, for the period 1993-2013 to calculate the reference peak geoelectric field amplitude. As described in the 2016 NERC White Paper, to arrive at a reference peak geoelectric field amplitude of 8 V/km, NERC "spatially averaged" four different station groups each spanning a square area of approximately 500 km (roughly 310 miles) in width.[18]

2. Order No. 830

14. On January 21, 2015, NERC submitted for Commission approval Reliability Standard TPL-007-1 in response to a directive in Order No. 779, which directed NERC to develop one or more Reliability Standards to address the effects of GMD events on the electric grid.[19] In Order No. 830, the Commission approved Reliability Standard TPL-007-1, concluding that Reliability Standard TPL-007-1 addressed the Commission's directive by requiring applicable Bulk-Power System owners and operators to conduct, on a recurring five-year cycle, initial and ongoing vulnerability assessments regarding the

[18] "Spatial Averaging" refers to the averaging of magnetometer readings over a geographic area. The standard drafting team averaged several (but not all) geomagnetic field readings taken by magnetometers located within square geographical areas of 500 km per side.

[19] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147, *reh'g denied*, 144 FERC ¶ 61,113 (2013).

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potential impact of a benchmark GMD event on the Bulk-Power System as a whole and on Bulk-Power System components. In addition, the Commission determined that Reliability Standard TPL-007-1 requires applicable entities to develop and implement corrective action plans to mitigate vulnerabilities identified through those recurring vulnerability assessments and that potential mitigation strategies identified in Reliability Standard TPL-007-1 include, but are not limited to, the installation, modification or removal of transmission and generation facilities and associated equipment.

15. In Order No. 830, the Commission also determined that Reliability Standard TPL-007-1 should be modified. Specifically, Order No. 830 directed NERC to develop and submit modifications to Reliability Standard TPL-007-1 concerning: (1) the calculation of the reference peak geoelectric field amplitude component of the benchmark GMD event definition; (2) the collection and public availability of necessary GIC monitoring and magnetometer data; and (3) deadlines for completing corrective action plans and the mitigation measures called for in corrective action plans. Order No. 830 directed NERC to develop and submit these revisions for Commission approval within 18 months of the effective date of Order No. 830.

16. With respect to the calculation of the reference peak geoelectric field amplitude component of the benchmark GMD event definition, Order No. 830 expressed concern with relying solely on spatial averaging in Reliability Standard TPL-007-1 because "the use of spatial averaging in this context is new, and thus there is a dearth of information or

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research regarding its application or appropriate scale."[20] While Order No. 830 directed that the peak geoelectric field amplitude should not be based solely on spatially-averaged data, the Commission indicated that this "directive should not be construed to prohibit the use of spatial averaging in some capacity, particularly if more research results in a better understanding of how spatial averaging can be used to reflect actual GMD events."[21]

D. NERC Petition and Proposed Reliability Standard TPL-007-2

17. NERC states that proposed Reliability Standard TPL-007-2 enhances currently-effective Reliability Standard TPL-007-1 by addressing reliability risks posed by GMDs more effectively and implementing the directives in Order No. 830.[22] NERC asserts that proposed Reliability Standard TPL-007-2 reflects the latest in GMD understanding and provides a technically sound and flexible approach to addressing the concerns discussed in Order No. 830. NERC contends that the proposed modifications enhance reliability by expanding GMD vulnerability assessments to include severe, localized impacts and by implementing deadlines and processes to maintain accountability in the development, completion, and revision of corrective action plans developed to address identified vulnerabilities. Further, NERC states that the proposed modifications improve the

[20] Order No. 830, 156 FERC ¶ 61,215 at P 45.

[21] *Id.* P 46.

[22] Proposed Reliability Standard TPL-007-2 is not attached to this Notice of Proposed Rulemaking (NOPR). Proposed Reliability Standard TPL-007-2 is available on the Commission's eLibrary document retrieval system in Docket No. RM18-8-000 and on the NERC website, www.nerc.com.

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availability of GMD monitoring data that may be used to inform GMD vulnerability assessments.

18. Proposed Reliability Standard TPL-007-2 modifies currently-effective Reliability Standard TPL-007-1 by requiring applicable entities to: (1) conduct supplemental GMD vulnerability and transformer thermal impact assessments in addition to the existing benchmark GMD vulnerability and transformer thermal impact assessments required in Reliability Standard TPL-007-1; (2) collect data from GIC monitors and magnetometers as necessary to enable model validation and situational awareness; and (3) develop necessary corrective action plans within one year from the completion of the benchmark GMD vulnerability assessment, include a two-year deadline for the implementation of non-hardware mitigation, and include a four-year deadline to complete hardware mitigation.[23]

19. In particular, proposed Reliability Standard TPL-007-2 modifies Requirements R1 (identification of responsibilities) and R2 (system and GIC system models) to extend the existing requirements pertaining to benchmark GMD assessments to the proposed supplemental GMD assessments. Proposed Reliability Standard TPL-007-2 adds the newly mandated supplemental GMD vulnerability and transformer thermal impact assessments in new Requirements R8 (supplemental GMD vulnerability assessment),

[23] Unless otherwise indicated, the requirements of proposed Reliability Standard TPL-007-2 are substantively the same as the requirements in currently-effective Reliability Standard TPL-007-1. Proposed Reliability Standard TPL-007-2 contains conforming and other non-substantive modifications that are not addressed in this NOPR.

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R9 (GIC flow information needed for supplemental GMD thermal impact assessments) and R10 (supplemental GMD thermal impact assessments). The supplemental GMD event definition contains a higher, non-spatially-averaged reference peak geoelectric field amplitude component than the benchmark GMD event definition (12 V/km versus 8 V/km). These three new requirements largely mirror existing Requirements R4, R5, and R6 that currently apply, and would continue to apply, only to benchmark GMD vulnerability and transformer thermal impact assessments.[24]

20. In addition, proposed Reliability Standard TPL-007-2 includes two other new requirements, Requirements R11 and R12, that require applicable entities to gather GIC monitored data (Requirement R11) and magnetometer data (Requirement R12).

21. Proposed Reliability Standard TPL-007-2 modifies existing Requirement R7 (corrective action plans) to create a one-year deadline for the development of corrective action plans and two and four-year deadlines to complete actions involving non-hardware and hardware mitigation, respectively, for vulnerabilities identified in the benchmark GMD assessment. The proposed modifications to Requirement R7 include a provision allowing for extension of deadlines if "situations beyond the control of the responsible entity determined in Requirement R1 prevent implementation of the [corrective action plan] within the timetable for implementation."

[24] An exception is the qualifying threshold for transformers required to undergo thermal impact assessments: for the supplemental GMD assessment the qualifying threshold for transformers is a maximum effective GIC value of 85 A/phase while the threshold for benchmark GMD event assessments is 75 A/phase.

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II. Discussion

22. Pursuant to section 215(d) of the FPA, the Commission proposes to approve Reliability Standard TPL-007-2 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. Proposed Reliability Standard TPL-007-2 addresses the directives in Order No. 830 to modify currently-effective Reliability Standard TPL-007-1: (1) to revise the benchmark GMD event definition, as it pertains to the required GMD Vulnerability Assessments and transformer thermal impact assessments, so that the definition is not based solely on spatially-averaged data; (2) to require the collection of necessary GIC monitoring and magnetometer data; and (3) to include a one-year deadline for the completion of corrective action plans and two and four-year deadlines to complete mitigation actions involving non-hardware and hardware mitigation, respectively.[25]

23. Proposed Reliability Standard TPL-007-2 complies with the directives in Order No. 830 by requiring, in addition to the benchmark GMD event vulnerability and thermal impact assessments, supplemental GMD vulnerability and thermal impact assessments. The supplemental GMD event definition in proposed Reliability Standard TPL-007-2 contains a non-spatially-averaged reference peak geoelectric field amplitude component

[25] NERC states that it will address the directive in Order No. 830 on public dissemination of GIC monitoring and magnetometer data through a forthcoming NERC data request to applicable entities pursuant to Section 1600 of the NERC Rules of Procedure rather than through a Reliability Standard requirement. On February 7, 2018, NERC released a draft data request for a 45-day comment period. After reviewing the comments, NERC indicates that it intends to seek authorization from the NERC Board of Trustees to issue the data request in August 2018. NERC Petition at 27.

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of 12 V/km, in contrast to the 8 V/km figure in the spatially-averaged benchmark GMD event definition. As NERC explains in its petition, the supplemental GMD event will be used to "represent conditions associated with localized enhancement of the geomagnetic field during a severe GMD event for use in assessing GMD impacts."[26] Proposed Reliability Standard TPL-007-2 therefore addresses the Commission's directive to modify currently-effective Reliability Standard TPL-007-1 so that the benchmark GMD event does not rely solely on spatially-averaged data to calculate the reference peak geoelectric field amplitude.

24. While proposed Reliability Standard TPL-007-2 addresses the first directive in Order No. 830 by requiring applicable entities to conduct supplemental GMD vulnerability and thermal impact assessments, the proposed Reliability Standard does not require applicable entities to mitigate such vulnerabilities. Instead, proposed Reliability Standard TPL-007-2, Requirement R8.3 only requires applicable entities to make "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s)" if a supplemental GMD event is assessed to result in Cascading.[27] As discussed below, NERC's proposal differs significantly from Order No. 830 because the intent of the directive was not only to

[26] NERC Petition at 12.

[27] The NERC Glossary defines Cascading as "uncontrolled successive loss of System Elements triggered by an incident at any location … [c]ascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies." Glossary of Terms Used in NERC Reliability Standards (January 31, 2018).

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identify vulnerabilities arising from localized GMD events but also to mitigate such vulnerabilities. Moreover, Order No. 830 reiterated the directive in Order No. 779 that NERC develop a second stage GMD Reliability Standard requiring GMD vulnerability assessments and that "owners and operators [] develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System."[28] Accordingly, the Commission proposes to direct NERC, pursuant to section 215(d)(5) of the FPA, to develop and submit modifications to the Reliability Standard to require applicable entities to develop and implement corrective action plans to mitigate supplemental GMD event vulnerabilities. The Commission proposes to direct NERC to submit the modified Reliability Standard for approval within 12 months from the effective date of Reliability Standard TPL-007-2.

25. In addition, as discussed below, the Commission seeks comment on the need for Requirement R7.4 of proposed Reliability Standard TPL-007-2, which allows applicable entities to extend corrective action plan implementation deadlines, as compared to a process whereby NERC considers extensions on a case-by-case basis, as suggested in Order No. 830.[29] After reviewing the comments, the Commission may approve the requirement but direct NERC to prepare and submit a report concerning the use of corrective action plan deadline extensions as allowed under proposed Reliability Standard TPL-007-2, Requirement R7.4. Under such a directive, NERC would submit the

[28] Order No. 830, 156 FERC ¶ 61,215 at P 7.

[29] *Id.* P 102.

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report within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2. Alternatively, pursuant to section 215(d)(5) of the FPA, the Commission may direct NERC to modify the Reliability Standard to remove Requirement R7.4.

A. Corrective Action Plan for Supplemental GMD Event Vulnerabilities NERC Petition

26. In requiring applicable entities to assess their vulnerabilities to a supplemental GMD event, NERC states that geomagnetic fields during severe GMD events can be spatially non-uniform with higher and lower strengths across a geographic region. NERC explains that the supplemental GMD event was derived using individual station measurements rather than spatially-averaged measurements, and thus includes localized enhancement of field strength above the average value found in the benchmark GMD event. NERC contends that the supplemental GMD event thus addresses the directive in Order No. 830 to revise Reliability Standard TPL-007-1 to account for the effects of localized peaks that could potentially affect reliable operations.

27. NERC maintains that the benchmark GMD event and supplemental GMD event are similar in structure but the supplemental GMD event contains differences to account for localized impacts. NERC explains that, like the benchmark GMD event, the supplemental GMD event defines the geomagnetic and geoelectric field values used to compute GIC flows for use in a GMD vulnerability assessment and is composed of four elements: (1) reference peak geoelectric field amplitude of 12 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local

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geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a locally-enhanced reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

28. NERC states that the higher reference peak geoelectric field amplitude (12 V/km compared to 8 V/km used in the benchmark GMD event) and local enhancements to the geomagnetic field time series or waveform are distinguishing characteristics of the supplemental GMD event and are intended to represent conditions associated with localized enhancement of the geomagnetic field during a severe GMD event for use in assessing GMD impacts.[30]

29. In developing the supplemental GMD event, NERC indicates that the standard drafting team ensured that the peak geoelectric field does not rely on spatial averaging of geomagnetic field data. NERC states that, like the value in the existing benchmark GMD event, the supplemental GMD event peak geoelectric field is a 1-in-100 year extreme value determined using statistical analysis of historical geomagnetic field data. NERC explains that the fundamental difference in the supplemental GMD event amplitude is that it is based on geomagnetic field observations taken at individual observation stations

[30] NERC states that the supplemental GMD event waveform is more severe than the benchmark GMD event waveform because it includes a five-minute duration enhanced peak up to 12 V/km for the reference earth model and 60 degree geomagnetic latitude. NERC Petition at 13. NERC explains that this synthetic enhancement represents the observed localized, rapid magnetic field variation periods associated with ionospheric sources during some severe GMD events. *Id.* NERC observes that such GMD conditions could result in increased transformer heating for short durations during a severe GMD event due to increased GIC flows. *Id.*

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(i.e., localized measurements), instead of the spatially-averaged geoelectric fields used in the benchmark GMD event. NERC states that the result of the extreme value analysis shows that the supplemental GMD event peak of 12 V/km is above the upper limit of the 95 percent confidence interval for a 100-year interval, while the same confidence interval with spatially-averaged data (i.e., the benchmark GMD event) is 8 V/km.

30. NERC indicates that the corrective action plans mandated in Requirement R7 continue to apply only if an entity has identified system performance issues through the benchmark GMD vulnerability assessments. NERC explains that mitigation for assessed supplemental GMD vulnerabilities are addressed in proposed Requirement R8.3, which states that if a responsible entity concludes that there would be "Cascading" caused by the supplemental GMD event, the entity shall conduct an analysis of possible actions to reduce the likelihood or mitigate the impacts of the event.[31]

31. NERC states that the standard drafting team determined that requiring corrective action plans in response to assessed supplemental GMD event vulnerabilities would not be appropriate at this time because the supplemental GMD event definition uses a small number of observed localized enhanced geoelectric field events that provide only general insight into the geographic size of localized events during severe solar storms.[32] NERC also contends that currently available modeling tools do not provide entities with

[31] NERC Petition at 23.

[32] *Id.*

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capabilities to model localized enhancements within a severe GMD event realistically.[33] As a result, NERC claims that applicable entities may need to employ conservative approaches when performing the supplemental GMD vulnerability assessment, such as applying the localized peak geoelectric field over an entire planning area.[34] NERC states that, for these reasons, "requiring mandatory mitigation may not provide effective reliability benefit or use resources optimally."[35] NERC contends that the approach used in proposed Reliability Standard TPL-007-2 for the supplemental GMD event provides entities with flexibility to consider and select mitigation actions based on their circumstances and is similar to the approach used in Reliability Standard TPL-001-4, Requirement R3.5 for extreme events.[36]

Commission Proposal

32. NERC's proposal not to require corrective action plans for supplemental GMD event vulnerabilities differs significantly from Order No. 830 because the intent and clear meaning of the directive was not only to identify vulnerabilities arising from localized GMD events but also to mitigate such vulnerabilities. Order No. 830 reiterated the directive in Order No. 779 that NERC develop a second stage GMD Reliability Standard requiring GMD vulnerability assessments and that "owners and operators [] develop

[33] *Id.*

[34] *Id.* at 24.

[35] *Id.*

[36] *Id.*

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and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System."[37] By contrast, proposed Reliability Standard TPL-007-2 allows supplemental GMD event vulnerabilities to potentially go unmitigated even, for example, if an applicable entity assesses that the supplemental GMD event causes Cascading.[38]

33. Moreover, in Order No. 830, the Commission directed NERC to "develop revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data."[39] NERC's proposal to modify the benchmark, but then allow applicable entities the discretion to take corrective action based solely on the results of the spatially-averaged benchmark analysis while taking under advisement ("an evaluation of possible actions") the results of the supplemental assessment, does not satisfy the clear intent of the Commission's directive.

34. Further, we are not persuaded by NERC's reasoning that: (1) existing technical limitations, specifically the limited number of observations used to define the supplemental GMD event and the availability of modeling tools to assist entities

[37] Order No. 830, 156 FERC ¶ 61,215 at P 7.

[38] Proposed Reliability Standard TPL-007-2, Requirement R8.3 ("If the analysis concludes there is Cascading caused by the supplemental GMD event described in Attachment 1, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.").

[39] *Id*. at 44.

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in assessing vulnerabilities, make requiring mitigation premature at this time; and (2) requiring only an evaluation of possible actions for supplemental GMD events that result in Cascading is similar to the treatment of extreme events in Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements).

35. We believe, based on the information before us, that it is reasonable to require applicable entities to mitigate supplemental GMD event vulnerabilities because, as NERC contends, the supplemental GMD event "provides a technically justified method of assessing vulnerabilities to the localized peak effects of severe GMD events."[40] While the supplemental GMD event possesses characteristics that differentiate it from the benchmark GMD event (i.e., geographic area, peak amplitude, duration, and geoelectric field waveform), both events were developed by the standard drafting team using a common framework. The standard drafting team determined the peak amplitude of the supplemental GMD event using generalized extreme value statistical analysis methods, as it did for the benchmark GMD event, and found a consistent result of 12 V/km with a 95 percent confidence interval. Generalized extreme value analysis is well-supported in the technical literature and, in approving the benchmark GMD event, was previously accepted in Order No. 830. The basic waveform used for the supplemental GMD event is the same waveform used in the benchmark GMD event.[41] Similar to the methodology for

[40] NERC Petition at 13.

[41] *Id.* ("Both the benchmark and supplemental GMD event waveforms are based on 10-second sampling interval magnetic field data from the Ottawa observatory recorded during the March 13-14, 1989 GMD event.").

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determining peak amplitude, the benchmark GMD event waveform was previously considered appropriate in Order No. 830. While the supplemental GMD event waveform includes a "five-minute duration enhanced peak up to 12 V/km," NERC does not suggest that the duration of the enhanced peak is unrepresentative of the behavior of localized enhancements.

36. NERC contends that the low number of real-world observations on which the supplemental GMD event is based calls into question the accuracy of its geographic size.[42] However, any uncertainty regarding the size of the geographic footprint of the supplemental GMD event could be addressed by applicable entities through sensitivity analysis and other methods within the planning studies. The proposed Reliability Standard does not prescribe how applicable entities must perform such studies; so applicable entities may incorporate this uncertainty into their studies. Indeed, Attachment 1 (Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Events) of proposed Reliability Standard TPL-007-2 states that "Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations."[43] Attachment 1 provides that an applicable entity may apply the supplemental GMD event definition over the entire planning area; apply some

[42] *Id.* at 23 ("[the] small number of observed localized enhanced geoelectric field events … provide only general insight into the geographic size of localized events during severe solar storms").

[43] Proposed Reliability Standard TPL-007-2, Attachment 1, Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event.

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combination of the benchmark GMD event and supplemental GMD event over portions of a planning area; or use "[o]ther methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event."[44] The flexibility afforded to applicable entities by proposed Reliability Standard TPL-007-2 to determine the geographic size of the supplemental GMD event, in our view, addresses NERC's concern.

37. The Supplemental Geomagnetic Disturbance Event Description appended to NERC's petition further supports the supplemental GMD event definition by stating that "[b]ased on the above analysis and the previous work associated with the benchmark GMD event, it is reasonable to incorporate a second (or supplemental) assessment into TPL-007-2 to account for the potential impact of a local enhancement in both the network analysis and the transformer thermal assessment(s)."[45] The Supplemental GMD Event White Paper also states that "[g]iven the current state of knowledge regarding the spatial extent of a local geomagnetic field enhancements, upper geographic boundaries, such as the values used in the approaches above, are reasonable but are not definitive."[46]

38. With respect to NERC's contention regarding the unavailability of modeling tools, we are not persuaded. We understand that there are commercially available tools that

[44] *Id.*

[45] NERC Petition, Exhibit I (Supplemental Geomagnetic Disturbance Event Description) at 12 (Supplemental GMD Event White Paper).

[46] *Id.* at 13.

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could allow for modeling of supplemental GMD events.[47] In addition to these modeling tools, other methods could be used within the framework of the Reliability Standard to study planning areas (e.g., superposition or sensitivity studies) in conjunction with other power system modeling tools. However, we will consider any comments that substantiate NERC's position.

39. In addition, the Commission recognized in Order No. 830 that an improved understanding of GMDs is necessary and directed NERC to conduct certain GMD-related research. The GMD research directed in Order No. 830 is meant to address technical limitations regarding GMD mitigation, among other areas. In the preliminary GMD research work plan submitted by NERC on May 30, 2017, NERC stated that the Commission in Order No. 830 "noted its concern that a spatially-averaged benchmark may not adequately account for localized peak geoelectric fields that could potentially affect reliable operations."[48] In response, NERC indicated that it will conduct "(i) research [Task 1 of the GMD research work plan] to improve understanding of the characteristics and spatial scales of localized geoelectric field enhancements caused by severe GMD events; and (ii) research to determine the impacts of spatial averaging

[47] *See, e.g.*, Siemens Power Technologies International, GIC Module to Analyze Geomagnetic Disturbances on the Grid, Features Summary, http://w3.usa.siemens.com/smartgrid/us/en/transmission-grid/products/grid-analysis-tools/transmission-system-planning/Documents/PTI_FF_EN_SWPE_GIC_1412.pdf; PowerWorld, Simulator, Geomagnetically Induced Current (GIC), https://www.powerworld.com/products/simulator/add-ons-2/simulator-gic.

[48] NERC, Geomagnetic Disturbance Research Work Plan of the North American Electric Reliability Corporation, Docket No. RM15-11-002, at 8 (filed May 30, 2017).

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assumptions on [Bulk-Power System] reliability."[49] NERC estimated that Task 1, which includes the development of better models, will require approximately 24-36 months to complete from start of work. Such GMD research on localized events should inform the standard development process and aid applicable entities when implementing a modified Reliability Standard.[50]

40. We are also not persuaded by NERC's reliance on Reliability Standard TPL-001-4 to justify only requiring an evaluation of possible actions for supplemental GMD events that result in Cascading in light of the directive in Order No. 830. In Order No. 830, the Commission directed NERC to modify the proposed Reliability Standard to assess and address the risks posed by enhanced localized GMD events to the Bulk-Power System. In contrast, in approving Reliability Standard TPL-001-4, the Commission did not direct NERC to further modify the Reliability Standard to address the risks posed by extreme events. Accordingly, the treatment of extreme events under Reliability Standard TPL-001-4 does not support the notion here that applicable entities should, as NERC suggests, have the "the flexibility to … *consider* mitigation."[51] However, as with the mitigation of

[49] *Id.*

[50] On April 19, 2018, NERC submitted a revised GMD Work Plan that is currently pending before the Commission. NERC, Revised Geomagnetic Disturbance Research Work Plan of the North American Electric Reliability Corporation, Docket No. 15-11-003 (filed April 19, 2018). The revised GMD Work Plan provides additional detail to the previous version. NERC now estimates that Task 1 deliverables will be completed in 2019. *Id.*, Attachment 1 (Order No. 830 GMD Research Work Plan (April 2018)) at 7.

[51] NERC Petition at 24 (emphasis added).

benchmark GMD event vulnerabilities, we agree with NERC that any required mitigation of supplemental GMD event vulnerabilities should be flexible in terms of how applicable entities choose to mitigate such vulnerabilities. NERC's petition already stresses that proposed Reliability Standard TPL-007-2 affords flexibility as to how applicable entities apply the supplemental GMD event to their planning areas.[52]

41. Accordingly, the Commission proposes to direct NERC, pursuant to section 215(d)(5) of the FPA, to develop and submit modifications to the Reliability Standard to require applicable entities to develop and implement corrective action plans to mitigate supplemental GMD event vulnerabilities. The Commission proposes to direct NERC to submit the modified Reliability Standard for approval within 12 months from the effective date of Reliability Standard TPL-007-2. The Commission seeks comments from NERC and other interested entities on this proposal.

B. Corrective Action Plan Deadline Extensions

NERC Petition

42. NERC states that proposed Reliability Standard TPL-007-2, Requirement R7.2 requires responsible entities to develop a corrective action plan within one year of the benchmark GMD vulnerability assessment, if the entity concludes that its System does not meet the performance requirements for the steady state planning benchmark GMD event. NERC indicates that under Requirement R7.3, the corrective action plan shall

[52] NERC Petition, Exhibit I at 13 ("Proposed TPL-007-2 provides flexibility for planners to determine how to apply the supplemental GMD event to the planning area.").

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include a timeline that specifies the completion of non-hardware and hardware mitigation within two and four years of development of the corrective action plan, respectively.

43. NERC maintains that proposed Reliability Standard TPL-007-2 also recognizes that there may be circumstances outside of a responsible entity's control that could prevent the completion of a mitigation activity within the specified timetable. NERC cites as examples delays due to regulatory or legal processes, such as permitting; delays from stakeholder processes required by tariffs; delays resulting from equipment lead times; or delays resulting from the inability to acquire necessary right-of-way. NERC explains that in such circumstances, a responsible entity may maintain compliance by revising its corrective action plan in accordance with Requirement R7.4. NERC states that under Requirement R7.4, the responsible entity shall revise its corrective action plan if events beyond its control prevent implementation within the original timetable. NERC explains that in the revised corrective action plan, the responsible entity must provide justification for its revised timetable by documenting: (1) the circumstances causing the delay; (2) description of the original corrective action plan and any changes; and (3) revisions to selected actions, including the use of any operating procedures if applicable, along with an updated timetable for completion. NERC states that the revised corrective action plan shall be updated at least annually and the responsible entity must then provide its revised corrective action plan to recipients of the original corrective action plan (i.e., reliability coordinator, adjacent planning coordinator(s), adjacent transmission planner(s), functional entities referenced in the corrective action plan, and

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any functional entity that submits a written request and has a reliability related need for the information).

44. NERC contends that this proposal is consistent with other Commission-approved Reliability Standards. NERC cites Reliability Standard FAC-003-4, Requirement R7 and asserts that it provides that an entity may modify its annual vegetation work plan in light of circumstances beyond the entity's control, such as a natural disaster or other circumstance. NERC also cites Reliability Standard PRC-004-5(i), Requirement R5 and contends that under that Reliability Standard a responsible entity that owns a protection system component that caused a misoperation shall either develop a corrective action plan or explain in a declaration why corrective actions are beyond the entity's control or would not improve reliability.

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Commission Proposal

45. Proposed Reliability Standard TPL-007-2 satisfies Order No. 830 by incorporating the deadlines set out by the Commission for the development and implementation of corrective action plans. However, Requirement R7.4 of the proposed Reliability Standard differs from Order No. 830 by allowing applicable entities to "revise" or "update" corrective action plans to extend deadlines. This provision contrasts with the Commission's guidance in Order No. 830 that "NERC should consider extensions of time on a case-by-case basis."[53]

46. NERC contends that the proposed Reliability Standard "would implement the Commission directed deadlines for Corrective Action Plans and mitigation, along with a process to maintain accountability and communication with affected entities when circumstances beyond a responsible entity's control affect the entity's ability to complete implementation within the original deadlines."[54] Given the complexities and potential novelty of steps applicable entities may take to mitigate the risks of GMDs, we agree with NERC that there should be a mechanism for allowing extensions of corrective action plan implementation deadlines. However, we would like to avoid unnecessary delay in implementing protection against GMD threats. Moreover, we are not persuaded that the proposal is supported by the precedent cited by NERC because the Reliability Standards NERC cites are distinguishable.

[53] Order No. 830, 156 FERC ¶ 61,215 at P 102.

[54] NERC Petition at 22.

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47. NERC maintains that provisions similar to Requirement R7.4 are found in two Reliability Standards. NERC states that Reliability Standard FAC-003-4, Requirement R7, allows a registered entity to modify its annual vegetation work plan in light of circumstances beyond the entity's control. While Reliability Standard FAC-003-4, Requirement R7 permits modifications to annual vegetation work plans, the modifications cannot result in a registered entity's failure to avoid the damage contemplated by Requirement R7—vegetation encroachment: "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 [minimum vegetation clearance distance]) and must be documented." In contrast, proposed Requirement R7.4 could enable applicable entities to delay mitigation that would avoid the damage of known GMD vulnerabilities. Accordingly, the extensions of time permitted by Reliability Standard FAC-003-4, because they may not result in the damage contemplated by the Reliability Standard, are not comparable, as NERC asserts, to failure to mitigate an existing GMD vulnerability in a timely manner.

48. NERC also compares the corrective action plan provision in proposed Reliability Standard TPL-007-2 with Reliability Standard PRC-004-5(i), Requirement R5, which allows "a responsible entity that owns a Protection System component that caused a Misoperation … [to] either develop a Corrective Action Plan or explain in a declaration why corrective actions are beyond the entity's control or would not improve reliability." We are not persuaded that NERC's proposal to allow self-declared extensions of time in Requirement R7.4 is supported by the quoted language in Reliability Standard

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PRC-004-5(i), Requirement R5 because Requirement R5 does not allow for extensions of time. Rather, Requirement R5 permits the registered entity to declare that it cannot carry out corrective actions (e.g., because the misoperation occurred on facilities it does not own or control) or because the corrective action would not improve Bulk-Power System reliability. Moreover, the Guidelines and Technical Basis document accompanying Reliability Standard PRC-004-5(i) concludes by stating that a "declaration that no further corrective actions will be taken is expected to be used sparingly."

49. Given these concerns, the Commission is considering two options in response to Requirement R7.4 of the proposed Reliability Standard. The Commission seeks comment from NERC and other interested entities on each of these proposals.

50. Under the first option, the Commission would, pursuant to section 215(d)(5) of the FPA, direct NERC to modify the proposed Reliability Standard to comport with Order No. 830, by requiring that NERC and the Regional Entities, as appropriate, consider requests for extension of time on a case-by-case basis.[55] Under this option, responsible entities seeking an extension would submit the information required by proposed Requirement R7.4 to NERC and the Regional Entities for their consideration of the request. The Commission would also direct NERC to prepare and submit a report addressing the disposition of any such requests, as well as information regarding how often and why applicable entities are exceeding corrective action plan deadlines

[55] Order No. 830, 156 FERC ¶ 61,215 at P 102.

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following implementation of the proposed Reliability Standard.[56] Under such a directive, NERC would submit the report within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2. Following receipt of the report, the Commission would determine whether further action is necessary.

51. Under the second option, the Commission would approve proposed Requirement R7.4 but also direct NERC to prepare and submit a report regarding how often and why applicable entities are exceeding corrective action plan deadlines following implementation of the proposed Reliability Standard. Under such a directive, NERC would submit the report within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2. Following receipt of the report, the Commission would determine whether further action is necessary.

III. Information Collection Statement

52. The collection of information contained in this Notice of Proposed Rulemaking is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[57] OMB's regulations require review and

[56] Under proposed Requirement R7.4, when an applicable entity extends a corrective action plan deadline, it must revise the corrective action plan to explain the "[c]ircumstances causing the delay for fully or partially implementing the selected actions." NERC could use this information to populate the proposed report.

[57] 44 U.S.C. 3507(d) (2012).

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approval of certain information collection requirements imposed by agency rules.[58] Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the information collection requirements of a rule will not be penalized for failing to respond to the collection of information unless the collection of information displays a valid OMB control number.

53. We solicit comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. Specifically, the Commission asks that any revised burden or cost estimates submitted by commenters be supported by sufficient detail to understand how the estimates are generated.

54. The Commission proposes to approve proposed Reliability Standard TPL-007-2, which would replace currently-effective Reliability Standard TPL-007-1. When compared to Reliability Standard TPL-007-1, proposed Reliability Standard TPL-007-2 maintains the current information collection requirements, modifies existing Requirement R7 and adds new requirements in Requirements R8 through R12.

55. Proposed Reliability Standard TPL-007-2 includes new corrective action plan development and implementation deadlines in Requirement R7, new supplemental GMD vulnerability and transformer thermal impact assessments in Requirements R8 through

[58] 5 CFR 1320 (2017).

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R10, and requirements for applicable entities to gather magnetometer and GIC monitored data in Requirements R11 and R12. Deadlines in Requirement R7 for the development and implementation of corrective action plans would only change the timeline of such documentation and are not expected to revise the burden to applicable entities. The burden estimates for new Requirements R8 through R10 are expected to be similar to the burden estimates for Requirements R4 through R6 in currently-effective Reliability Standard TPL-007-1 due to the closely-mirrored requirements.[59] The Commission expects that only 25 percent or fewer of transmission owners and generator owners would have to complete a supplemental transformer thermal impact assessment per Requirement R10. Requirements R11 and R12 require applicable entities to have a process to collect GIC and magnetometer data from meters in planning coordinator planning areas.

Public Reporting Burden: The burden and cost estimates below are based on the changes to the reporting and recordkeeping burden imposed by proposed Reliability Standard TPL-007-2. Our estimates for the number of respondents are based on the NERC Compliance Registry as of 3/9/2018, which indicates there are 183 entities registered as transmission planner (TP), 65 planning coordinators (PC), 330 transmission owners (TO), 944 generator owners (GO) within the United States. However, due to significant overlap, the total number of unique affected entities (i.e., entities registered as a transmission planner, planning coordinator, transmission owner or generator owner, or some combination of these functional entities) is 1,130 entities. This includes

[59] NERC Petition at 15-17.

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188 entities that are registered as a transmission planner or planning coordinator (applicability for Requirements R7 to R9 and R11 to R12), and 1,119 entities registered as a transmission or generation owner (applicability for Requirement R10). Given the assumption above, there is an expectation that at most only 25 percent of the 1,119 entities (or 280 entities) will have to complete compliance activities for Requirement R10. The estimated burden and cost are as follow.[60]

FERC-725N, Changes Proposed in NOPR in Docket No. RM18-8[61, 62]						
Requirement (R)	Number and Type of Respondents (1)	Annual Number of Responses Per Respondent (2)	Total No. of Responses (1)X(2)=(3)	Average Burden Hrs. & Cost per Response (4)	Total Annual Burden Hrs. & Total Annual Cost (rounded)	Cost per Respondent ($) (5)÷(1)

[60] 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 2017 (https://www.bls.gov/news.release/ecec.nr0.htm). We estimate that an Electrical Engineer (NAICS code 17-2071) would perform the functions associated with reporting requirements, at an average hourly cost (for wages and benefits) of $66.90. The functions associated with recordkeeping requirements, we estimate, would be performed by a File Clerk (NAICS code 43-4071) at an average hourly cost of $32.04 for wages and benefits.

The estimated burden and cost are in addition to the burden and cost that are associated with the existing requirements in Reliability Standard TPL-007-1 (and in the current OMB-approved inventory), which would continue under proposed Reliability Standard TPL-007-2.

[61] Rep.=reporting requirements; RK =recordkeeping requirements.

[62] For each Reliability Standard, the Measure shows the acceptable evidence (Reporting Requirement) for the associated Requirement (R numbers), and the Compliance section details the related Recordkeeping Requirement.

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					(3)X(4)=(5)	
R1 through R6	No change	No change	No change	No change	No change	No change
R7	188 (PC and TP)	1/5 (once for every five year study)	37.6	Rep. 5 hrs., $334.5; RK 5 hrs., $160.2	Rep. 188 hrs.,$12,577; RK 188 hrs., $6,023	Rep. 1 hr., $66.9; RK 1 hr., $32.04
R8	188 (PC and TP)	1/5 (once for every five year study)	37.6	Rep., 27 hrs., $1,806.30; RK, 21 hrs., $672.84	Rep. 1,015 hrs., $67,917; RK 790 hrs., $25,299	Rep., 5.4 hrs., $361.26; RK 4.2 hrs., $134.57
R9	188 (PC and TP)	1/5 (once for every five year study)	37.6	Rep. 9 hrs., $602.10 RK 7 hrs., $224.28	Rep. 338 hrs.; $22,639 RK 263 hrs., $8,432	Rep. 1.8 hrs., $120.42; RK 1.4 hrs., $44.85
R10	280 (25% of 1,119) (GO and TO)	1/5 (once for every five year study)	56	Rep. 22 hrs., $1,471.8; RK 18 hrs. $576.72	Rep. 1,232 hrs., $82,421; RK 1,008 hrs., $32,296	Rep. ;4.4 hrs., $294.36; RK 3.6 hrs., $115.34
R11	188 (PC and TP)	1 (on-going reporting)	188	Rep. 10 hrs., $669; RK. 10 hrs., $320.40	Rep. 1,880 hrs., $125,772; RK 1,880 hrs., $60,235	Rep. 10 hrs., $669; RK 10 hrs., $320.40
R12	188 (PC and TP)	1 (on-going reporting)	188	Rep. 10 hrs., $669 RK. hrs 320.4	Rep. 1,880 hrs. $125,772; RK 1,880 hrs., $60,235	Rep. 10 hrs., $669; RK 10 hrs., $320.40
Total Additional Hrs. and					Rep., 6,533 hrs.,	

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Cost (rounded), due to NOPR in RM18-8					$437,057; RK 6,009 hrs., $192,528	

Title: FERC-725N, Mandatory Reliability Standards: TPL Reliability Standards.

Action: Proposed revisions to an existing collection of information.

OMB Control No: 1902-0264.

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

Frequency of Responses:[63] Every five years (for Requirement R7-R10), annually (for Requirement R11 and R12).

Necessity of the Information: Proposed Reliability Standard TPL-007-2, if adopted, would implement the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, these requirements address the threat posed by GMD events to the Bulk-Power System and conform to the Commission's directives to modify Reliability Standard TPL-007-1 as directed in Order No. 830.

Internal review: The Commission has reviewed proposed Reliability Standard TPL-007-2, and made a determination that its action is necessary to implement

[63] The frequency of Requirements R1 through R6 in proposed Reliability Standard TPL-007-2 is unchanged from the existing requirements in Reliability Standard TPL-007-1.

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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.

56. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873]. Comments concerning the proposed collection of information and the associated burden estimate should be sent to the Commission in this docket and may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. Due to security concerns, comments should be sent electronically to the following e-mail address: oira_submission@omb.eop.gov. Comments submitted to OMB should refer to FERC-725N and OMB Control No. 1902-0264.

IV. Environmental Analysis

57. 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.[64] The Commission has categorically excluded certain actions

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

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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.[65] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

58. The Regulatory Flexibility Act of 1980 (RFA)[66] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The definition of small business is provided by the Small Business Administration (SBA) at 13 CFR 121.201. The threshold for a small utility (using SBA's sub-sector 221) is based on the number of employees for a concern and its affiliates. As discussed above, proposed Reliability Standard TPL-007-2 would apply to a total of 1,130 unique planning coordinators, transmission planners, transmission owners, and generation owners.[67] A small utility (and its affiliates) is defined as having no more than the following number of employees:

- for planning coordinators, transmission planners, and transmission owners (NAICS code 221121, Electric Bulk Power Transmission and Control), a maximum of 500 employees

[65] 18 CFR 380.4(a)(2)(ii) (2017).

[66] 5 U.S.C. 601-12 (2012).

[67] In the NERC Registry, there are approximately 65 PCs, 188 TPs, 944 GOs, and 330 TOs (in the United States), which will be affected by this NOPR. Because some entities serve in more than one role, these figures involve some double counting.

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- for generator owners, a maximum of 750 employees.[68]

59. The total cost to all entities (large and small) is $629,585 annually (or an average of $1,345.27 for each of the estimated 468 entities affected annually). For the estimated 280 generator owners and transmission owners affected annually, the average cost would be $409.70 per year. For the estimated 188 planning coordinators and transmission planners, the estimated average annual cost would be $2,738.84. The estimated annual cost to each affected entity varies from $409.70 to $2,738.84 and is not considered significant.

60. Accordingly, the Commission certifies that the proposals contained in this NOPR will not have a significant economic impact on a substantial number of small entities. The Commission seeks comment on this certification.

VI. Comment Procedures

61. 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 date of publication in the FEDERAL REGISTER**]. Comments must refer to Docket No. RM18-8-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

[68] The maximum number of employees for a generator owner (and its affiliates) to be "small" varies from 250 to 750 employees, depending on the type of generation (e.g., hydroelectric, nuclear, fossil fuel, wind). For this analysis, we use the most conservative threshold of 750 employees.

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62. 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.

63. 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.

64. 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

65. 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.

66. 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

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Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number, excluding the last three digits of this document in the docket number field.

67. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at 202-502-8371, TTY 202-502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)

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163 FERC ¶ 61,125
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Parts 375 and 388

[Docket No. RM16-15-001; Order No. 833-A]

Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information

(Issued May 17, 2018)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order on Clarification and Rehearing.

SUMMARY: The Federal Energy Regulatory Commission (Commission) in this order on clarification and rehearing grants in part Edison Electric Institute's request for clarification or, in the alternative, rehearing of Order No. 833, and denies rehearing of that order, which amends the Commission's regulations to implement provisions of the Fixing America's Surface Transportation Act pertaining to the designation, protection, and sharing of Critical Energy/Electric Infrastructure Information.

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

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION

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163 FERC ¶ 61,125
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information — Docket No. RM16-15-001

ORDER NO. 833-A

ORDER ON CLARIFICATION AND REHEARING

(Issued May 17, 2018)

1. In Order No. 833, the Commission amended its regulations to implement provisions of the Fixing America's Surface Transportation Act (FAST Act)[1] related to Critical Electric Infrastructure Information.[2] In addition, Order No. 833 revised the Commission's Critical Energy Infrastructure Information regulations.[3] Edison Electric Institute (EEI) requested clarification or, in the alternative, rehearing of Order No. 833. For the reasons discussed below, we grant EEI's request for clarification in part and deny rehearing.

I. Order No. 833

2. On December 4, 2015, the FAST Act was signed into law. The FAST Act, *inter alia*, added section 215A to the Federal Power Act (FPA) to improve the security and resilience of energy infrastructure in the face of emergencies. The FAST Act directed the

[1] Fixing America's Surface Transportation Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1773-1779 (2015) (codified at 16 U.S.C. 824o-1).

[2] *Regulations Implementing FAST Act Section 61003 — Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information, Availability of Certain North American Electric Reliability Corporation Databases to the Commission,* Order No. 833, 157 FERC ¶ 61,123 (2016).

[3] *Id.*

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Commission to issue regulations that provide: (1) the criteria and procedures for designating information as Critical Electric Infrastructure Information; (2) a specific prohibition on unauthorized disclosure of Critical Electric Infrastructure Information; (3) sanctions for the knowing and willful unauthorized disclosure of Critical Electric Infrastructure Information by Commission and Department of Energy (DOE) employees; and (4) a process for voluntary sharing of Critical Electric Infrastructure Information.[4]

3. On June 16, 2016, the Commission issued a Notice of Proposed Rulemaking (NOPR) to amend its regulations to implement the provisions of the FAST Act pertaining to the designation, protection, and sharing of Critical Electric Infrastructure Information and to revise the existing Critical Energy Infrastructure Information regulations.[5] The NOPR proposed that the amended procedures be referred to as the Critical Energy/Electric Infrastructure Information (CEII) Procedures.[6] In response to the NOPR, nineteen entities filed comments and two entities filed reply comments.

4. On November 17, 2016, the Commission issued Order No. 833, which amended the Commission's regulations at 18 C.F.R. §§ 375.309, 375.313, 388.112 and 388.113 to implement the FAST Act provisions that pertain to the designation, protection and sharing of Critical Electric Infrastructure Information. Order No. 833 also revised the existing Critical Energy Infrastructure Information regulations. The Commission determined that the amended regulations comply with the requirements of the FAST Act and better ensure the secure treatment of CEII.[7]

II. Discussion

5. EEI asserts that the Commission either erred or should reconsider five aspects of Order No. 833.[8] As discussed below, we grant EEI's request for clarification in part and deny EEI's request for rehearing.

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[4] *See generally* FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776.

[5] *Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information*, 155 FERC ¶ 61,278 (2016) (NOPR).

[6] *Id.*

[7] *See generally* Order No. 833, 157 FERC ¶ 61,123.

[8] EEI Request at 6-7.

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A. Requests for Access to CEII

Order No. 833

6. The FAST Act required the Commission, taking into account standards of the Electric Reliability Organization, to facilitate voluntary sharing of Critical Electric Infrastructure Information. The statute directed the Commission to facilitate voluntary sharing with, between, and by Federal, State, political subdivision, and tribal authorities; the Electric Reliability Organization; regional entities; information sharing and analysis centers established pursuant to Presidential Decision Directive 63; owners, operators, and users of critical electric infrastructure in the United States; and other entities determined appropriate by the Commission.[9]

7. In Order No. 833, the Commission established procedures in its regulations for providing CEII to third parties. Specifically, in section 388.113(f), the Commission established a process for the Commission to voluntarily share CEII when there is a need to ensure energy infrastructure is protected. Separately, in section 388.113(g), the Commission revised its long-standing procedures for members of the public to request access to CEII by requiring a statement demonstrating a valid and legitimate need for the information.[10] Both processes contain procedures to notify submitters of the CEII of the Commission's prospective sharing of its CEII as well as a requirement that prospective CEII recipients execute Non-Disclosure Agreements (NDA).

8. The Commission also stated that the procedures do not impose a sharing requirement on entities; instead, the provisions allow the Commission to exercise discretion to share CEII that has already been submitted to, or generated by, the Commission.[11] Further, the Commission determined that even if the Commission's voluntary sharing of information were viewed as the same as a third-party sharing it, the Commission must balance its obligation to disclose information as necessary to carry out the Commission's jurisdictional responsibilities against an entity's preference not to have information disclosed.[12]

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[9] FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776.

[10] The CEII request procedures found in section 388.113(g) were first established under the Commission's Critical Energy Infrastructure Information regulations in 2003. *See Critical Energy Infrastructure Information*, Order No. 630, FERC Stats. & Regs. ¶ 31,140, *order on reh'g*, Order No. 630-A, FERC Stats. & Regs. ¶ 31,147 (2003).

[11] Order No. 833, 157 FERC ¶ 61,123 at P 125.

[12] *Id.* P 126.

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Request

9. EEI states that the Commission should reconsider its determination that CEII can be shared over the objections of submitters.[13] EEI asserts that section 215A(d)(2)(D) of the FPA directs the Commission only to facilitate voluntary sharing "by and between" entities. EEI contends that the Commission's ability to share information over a submitter's objection, as provided in 18 C.F.R. § 388.113(g)(5)(iii), amounts to involuntary sharing not intended by the FAST Act and in violation of FPA section 215A(d)(6).[14] EEI asserts that, by using section 215A(d)(2)(D) to authorize the Commission to provide CEII over the submitter's objection, the Commission is using the FAST Act to "share" CEII in an involuntary manner. EEI states that its interpretation is consistent with Congress' decision to make CEII exempt from mandatory disclosure under the Freedom of Information Act (FOIA).[15]

Commission Determination

10. We deny clarification and rehearing of this issue. We disagree with EEI's contention that the FAST Act only directs the voluntary sharing of CEII "by and between" entities or that the Commission's release of information over a submitter's objections constitutes "involuntary" sharing of such information. EEI misconstrues FPA section 215A(d)(2)(D) to argue that the statute's directives regarding voluntary sharing do not include voluntary sharing of CEII *by the Commission*. Such a reading is inconsistent with the FAST Act in two respects.

11. First, FPA section 215A(d)(2)(D)(i) provides that the Commission's regulations should "facilitate voluntary sharing of critical electric infrastructure information with, between, and by— (i) Federal, State, political subdivision, and tribal authorities …" It would be incongruous to read the FAST Act's reference to "voluntary sharing … by … Federal … authorities" not to include voluntary sharing by the Commission of CEII in its possession. Second, the FAST Act did not direct the Commission to curtail or eliminate the established, pre-existing process for providing members of the public with access to CEII, which is provided in 18 C.F.R. § 388.113(g)(5)(iii).

12. Even before the FAST Act, the Commission's regulations included a process whereby the Commission's CEII Coordinator had the discretion to share, in certain

[13] EEI Request at 7.

[14] *Id.*

[15] *See* 5 U.S.C. 552 *as amended by* the FOIA Improvement Act of 2016, Pub. L. No. 114-185, 130 Stat. 538 (2016).

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circumstances, CEII that was submitted to, or generated by, the Commission.[16] Under both the prior regulations and the revised regulations at 18 C.F.R. § 388.113(d)(1)(vi), a submitter is, as EEI acknowledges, provided an opportunity to comment on the potential disclosure of its CEII.[17] Prior to any determination to release CEII to a requester, pursuant to 18 C.F.R. § 388.113(g)(5)(iii), the CEII Coordinator will take into consideration any objections and "will balance the requester's need for the information against the sensitivity of the information." Other than characterizing a determination by the CEII Coordinator to ultimately release CEII over an objection as "involuntary sharing," EEI does not propose any change to the Commission's long-standing approach nor does EEI demonstrate that the FAST Act is intended to restrict the Commission from sharing CEII, under an NDA, with third parties that have a valid and legitimate need for the material.[18]

13. In addition, our reading of the FAST Act is consistent with EEI's statement that "[u]nder the plain meaning of the FAST Act statute, the term 'voluntary' means the Commission should implement an information sharing process that allows owners to share information intentionally and freely."[19] The new voluntary sharing provisions, at 18 C.F.R § 388.113(f) of the Commission's CEII regulations, only govern the process by which the Commission will voluntarily share CEII that has been submitted to the Commission or generated by staff.[20] Before the FAST Act and under the revised

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[16] Order No. 833, 157 FERC ¶ 61,123 at P 125.

[17] EEI's argument pertains to the CEII request process found in 18 C.F.R. 388.113(g)(5) of the Commission's regulations. To the extent that EEI's argument indirectly relates to the separate voluntary sharing provisions found in section 388.113(f), its argument does not persuade us to grant rehearing on that section for the same reasons as those provided above. For example, under section 388.113(f), except in exigent circumstances, submitters are provided notice prior to release of CEII and may submit comments. In the event of an exigency like a national security issue, the Commission will provide notice of the disclosure to the submitter of CEII as soon as practicable.

[18] EEI's interpretation suggests that the determination as to whether it is appropriate for the Commission to share CEII should be entirely in the hands of the submitter. Such an approach is inconsistent with the FAST Act as it could limit the Commission's ability to share CEII. In any event, pursuant to 388.113(d)(1)(iv), a submitter is provided notice of release of CEII under 18 C.F.R. § 388.113(g)(5)(iii), and a submitter who disagrees with the determination providing notice of the release of its CEII has the ability to seek injunctive relief in district court.

[19] EEI Request at 7.

[20] As to sharing of CEII by CEII recipients, under our NDAs, CEII recipients may *(continued ...)*

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regulations, entities remain free to share the CEII that they submitted to the Commission with others.

14. Finally, we disagree with EEI's assertion that its interpretation of the FAST Act's "voluntary sharing" provisions is consistent with Congress' creation of a FOIA exemption for CEII.[21] The Commission's FOIA program and the voluntary sharing contemplated under the FAST Act serve different purposes, with the former serving to support government transparency[22] and the latter governing how certain sensitive information is identified, secured, and shared to support the security and resilience of critical energy infrastructure. We do not agree that the new FOIA exemption protecting against mandatory public disclosure of CEII in response to a FOIA request suggests that Congress also intended to prohibit *any* sharing of that CEII without the submitter's consent. Rather, the regulations adopted in Order No. 833 struck an appropriate balance between the FAST Act's provisions protecting CEII from public disclosure with the provisions providing that CEII may be voluntarily shared with certain third parties. Thus, while the FOIA exemption prevents the disclosure of CEII in response to a FOIA request, we disagree with EEI's assertion that the exemption was intended to preclude the Commission from exercising its discretion to share CEII pursuant to the established procedures in 18 C.F.R. § 388.113(g)(5)(iii).

B. Criteria for Responding to CEII requests

Order No. 833

15. In Order No. 833, the Commission concluded that the FAST Act does not require changes to the Commission's existing process for accessing CEII.[23] The Commission also decided to maintain its balancing approach when determining whether to provide CEII to individuals who demonstrated a need for access to CEII under an executed NDA.[24] The Commission noted that a request for access to CEII is case specific to the

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only share CEII with other individuals covered by our NDA for the same information.

[21] EEI Request at 7-8.

[22] *See, e.g., NLRB v. Robbins Tire & Rubber Co.*, 437 U.S. 214, 242 (1978) ("The basic purpose of FOIA is to ensure an informed citizenry, vital to the functioning of a democratic society, needed to check against corruption and to hold the governors accountable to the governed.").

[23] Order No. 833, 157 FERC ¶ 61,123 at P 144.

[24] *Id.* P 143.

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unique facts and circumstances of each request and, therefore, declined to provide additional guidance and criteria about how it will respond to individual CEII requests under 18 C.F.R. § 388.113(g)(5).[25]

Request

16. EEI asserts that the Commission erred by declining to provide or clarify the criteria that the Commission will use to determine whether a member of the public is eligible to obtain CEII from the Commission.[26] EEI claims that such clarification will provide clear guidance to Commission staff about when a member of the public may receive CEII and afford a better understanding to submitters about the "benefits or risks involved in providing CEII to the Commission."[27] EEI also contends that "criteria stating that the Commission will consider public safety benefits before releasing CEII to the public may provide CEII submitters with greater reasons to voluntarily provide CEII to the Commission."[28]

[25] The Commission, however, outlined the information that an individual seeking access to CEII under 18 C.F.R. § 388.113(g)(5) must include in an accompanying statement of need. *See id.*

[26] EEI Request at 6 (averring that nothing in section 388.113(g)(5)(iii) identifies any criteria that the Commission will use before disclosing CEII to a requester).

[27] *Id.* at 9.

[28] *Id.*

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Commission Determination

17. We grant clarification and deny rehearing of this issue. We continue to believe that the Commission has provided sufficient detail on the circumstances in which the Commission will share CEII.[29] The CEII regulations enable "individuals with a valid or legitimate need to access certain sensitive energy infrastructure information" that would otherwise be exempt under FOIA.[30]

18. Since instituting the CEII process in 2003, the Commission has acquired significant experience in processing CEII requests. In particular, the Commission routinely processes CEII requests from, among others, consultants, academics, landowners, and public interest groups. In implementing the provisions of the FAST Act, the Commission is utilizing its vast experience in addressing the various interests of CEII requestors and submitters as well.

19. Furthermore, we disagree with EEI's assertion that the Commission failed to provide any criteria that the CEII Coordinator will use to determine whether a member of the public is eligible to access CEII. As explained in Order No. 833, the Commission has utilized a "balancing approach effectively in response to Critical Energy Infrastructure Information requests for almost fifteen years. The balancing approach has provided to individuals with a demonstrated need access to information subject to a NDA."[31] Consistent with long-standing practice, section 388.113(g)(5)(iii) states that the "CEII Coordinator will balance the requester's need for the information against the sensitivity of the information."

20. Contrary to EEI's assertion, in the NOPR and in Order No. 833, we provided clarification regarding the criteria for obtaining CEII by outlining information that a CEII requester must include in its statement of need.[32] We also stated that a conclusory statement of need by a CEII requester will not suffice.[33] Moreover, we note that a request for access to CEII is case specific to the unique facts and circumstances of each request.

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[29] *See, e.g.,* 18 C.F.R § 388.113(f) (2017) (providing the procedures for voluntary sharing), § 388.113(g) (providing procedures for accessing CEII).

[30] Order No. 833, 157 FERC ¶ 61,123 at P 3.

[31] *Id.* P 143.

[32] 18 C.F.R. § 388.113(g)(5)(i)(b).

[33] *Id.*

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21. In its filing, EEI provides one suggestion (i.e., "public safety benefits") concerning how the Commission can enhance the criteria to determine whether a member of the public is eligible to obtain CEII from the Commission.[34] We clarify that public safety benefits are one criterion that the CEII Coordinator should consider, as part of the balancing approach described above, in determining whether to share CEII in a particular instance. Overall, we believe that our approach provides sufficient detail on the circumstances in which the Commission will share CEII, while also providing the CEII Coordinator with enough specificity and flexibility to respond to each individual request for CEII.

C. Non-Disclosure Agreement

Order No. 833

22. Order No. 833 included revisions to strengthen the CEII handling requirements for both Commission staff and external recipients. As part of those revisions, the Commission established minimum requirements for the NDAs that recipients of CEII must execute before receiving access to CEII. The Commission explained that the minimum requirements for an NDA are not exhaustive and do not preclude other requirements.[35] Further, the Commission stated that additional provisions may be added to the NDA and submitters may request additional provisions.[36] In response to NOPR comments, the Commission amended section 388.113(h)(2) to add a provision to require CEII recipients to promptly report all unauthorized disclosures of CEII to the Commission.[37]

Request

23. EEI states that the Commission should consider "modernizing the Commission's CEII NDA even further to mitigate against the risk of a CEII recipient involuntarily sharing CEII with a hostile actor."[38] EEI identifies one example of how the Commission may change the CEII NDA. While acknowledging the "incident response clause" in section 388.113(h)(2), EEI suggests that the clause could be changed to require the

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[34] EEI Request at 9.

[35] Order No. 833, 157 FERC ¶ 61,123 at P 92.

[36] *Id.*

[37] *Id.* P 93.

[38] EEI Request at 10-11.

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reporting of unauthorized disclosures that actually occurred or "those reasonably suspected to have occurred."[39]

Commission Determination

24. We grant clarification and deny rehearing on this issue. Order No. 833 explained that section 388.113(h)(2) only includes "'minimum' requirements for a NDA and is not intended to be exhaustive or preclude additional provisions, as needed."[40] As the Commission stated in Order No. 833, under certain circumstances the Commission may add additional provisions to the NDA and submitters may request that additional provisions be added to the NDA.[41] While we decline to make any changes to the minimum requirements for the NDA, the Commission reiterates that the CEII Coordinator may consider adding additional provisions to the NDA on a case by case basis. However, to the extent EEI seeks a specific change to the NDA or requests that the Commission take further comment on revisions to the NDA at this time, we deny those requests. EEI has not demonstrated that the NDA revisions that we have adopted, or the fact that we will entertain further changes to the NDA as appropriate, are unreasonable or arbitrary.

[39] *Id.* at 10.

[40] Order No. 833, 157 FERC ¶ 61,123 at P 92.

[41] *Id.* P 92.

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D. Designation of Commission-Generated Information

Order No. 833

25. In Order No. 833, the Commission determined that for Commission-generated information, the CEII Coordinator, after consultation with the appropriate Office Director, will determine whether the information is CEII.[42] The Commission concluded that stakeholder participation in CEII designations of Commission-generated information is unnecessary because the Commission has the expertise and experience to make such determinations.[43] The Commission also noted that in certain instances it would be inappropriate for stakeholders to be privy to Commission-generated information that potentially qualified as CEII.[44] Finally, the Commission stated that an entity is not precluded from raising concerns with the CEII Coordinator when an entity believes that Commission-generated information contains CEII about its facility.[45]

Request

26. EEI requests that the Commission clarify the existing procedures or provide the anticipated procedure for stakeholder "notification of, and opportunity to comment on, potential disclosure or sharing of Commission-generated information."[46] EEI asserts that the Commission erred by failing to provide a process for an entity to comment on the possible disclosure or sharing of Commission-generated CEII.[47] EEI contends that the Commission may incorporate a submitter's CEII in a Commission-generated CEII document that is released to a CEII requester without providing the submitter any opportunity to comment.

27. EEI also contends that the Commission could create a document that combines information that alone did not constitute CEII and was not submitted to the Commission as such, but that combined with other information could constitute CEII.[48] EEI states that

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[42] *Id.* P 59.

[43] *Id.* P 60.

[44] *Id.*

[45] *Id.* P 61.

[46] EEI Request at 6.

[47] *Id.*

[48] *Id.* at 13.

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in that instance, the submitter would not have had an opportunity to mark the information as CEII.[49] EEI maintains that, in these situations, it would be inconsistent for the Commission not to provide notice and an opportunity to comment.[50]

Commission Determination

28. We grant clarification and deny rehearing on this issue. The FAST Act implicitly recognizes that the Commission has the expertise and experience to determine whether any information, including Commission-generated information, is properly designated as CEII by vesting the Commission with the authority to designate information as CEII. The FAST Act does not require, and EEI identifies no provision in the FAST Act requiring, the Commission to provide notice and opportunity for public comment about the prospective release or sharing of Commission-generated CEII. Furthermore, the Commission is not persuaded that we should establish a requirement for stakeholder input when the Commission combines information not filed as CEII with other information and potentially creates CEII.

29. To the contrary, inherent differences between Commission-generated CEII and CEII from submitters, as well as practical considerations, warrant different procedures. As EEI acknowledges, there are circumstances in which it would be inappropriate for an outside entity to comment on the content of a non-public, Commission-generated CEII document. Nonetheless, EEI asks the Commission to develop a "consistent process" for stakeholder participation. We disagree and believe that crafting a broad notification requirement for each Commission-generated document that discusses CEII in some respect would be impractical and, as we noted in Order No. 833, often inappropriate.[51]

30. Therefore, EEI's arguments do not persuade us that a formal, mandatory stakeholder process is needed to comment on the release or sharing of Commission-

[49] *Id.*

[50] *Id.* at 13-14.

[51] Order No. 833, 157 FERC ¶ 61,123 at P 61. For example, Commission-generated documents may include other forms of non-public information such as pre-decisional, internal deliberations covered by the Deliberative Process Privilege. 5 U.S.C. § 552(b)(5)(2017) (protecting from disclosure "intra-agency memoranda or letters which would not be available by law to a party other than an agency in litigation with the agency."); *see Russell v. Dep't of the Air Force*, 682 F.2d 1045, 1048 (D.C. Cir. 1982); *see also Environmental Protection Agency v. Mink*, 410 U.S. 73, 87 (1973) (recognizing that "[i]t would be impossible to have any frank discussions of legal or policy matters in writing if all such writings were to be subjected to public scrutiny").

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generated CEII. We, however, clarify that nothing in the FAST Act or the Commission's CEII regulations prevents the CEII Coordinator from exercising discretion in an individual situation to solicit comments from a submitter of CEII or other information when evaluating whether to release a Commission-generated CEII document. We note that even if the Commission determines to release Commission-generated CEII, such a release would be pursuant to an NDA and the Commission's protections against further unwarranted or prohibited disclosure.

E. DOE's Criteria and Procedures for What Constitutes CEII

Order No. 833

31. In Order No. 833, the Commission declined to revise the CEII regulations to identify specific designation criteria and CEII procedures for DOE.[52] The Commission stated that the FAST Act does not compel DOE to make changes to its regulations and noted that nothing within the Commission's regulations limits DOE's ability to designate CEII in accordance with the FAST Act.[53]

Request

32. EEI asserts that the Commission erred in declining to provide or clarify the applicability of any procedure or process for stakeholders regarding DOE designations of its information as CEII.[54] Specifically, EEI requests that the Commission confirm that DOE determinations regarding CEII will be conducted pursuant to the Commission's CEII regulations.[55] EEI further requests that if that is not the case, the Commission should clarify that position, so EEI can seek further clarification from DOE as to the applicable procedures and criteria DOE intends to use for such determinations.[56]

Commission Determination

33. We deny rehearing on this issue. In Order No. 833, the Commission declined to revise our regulations to identify specific designation criteria and CEII procedures that

[52] Order No. 833, 157 FERC ¶ 61,123 at P 39.

[53] *Id.*

[54] EEI Request at 7.

[55] *Id.* at 16.

[56] *Id.*

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would be required for DOE.[57] EEI's argument here does not persuade us to change that determination. Specifically, section 215A(d)(3) of the FAST Act provides that information "may be designated" by the Commission and DOE pursuant to the criteria and procedures that the Commission establishes.[58] As explained in Order No. 833, nothing within the FAST Act compels DOE to make changes to its regulations, and nothing in the Commission's regulations limits DOE's ability to designate information in accordance with the FAST Act.[59]

[57] Order No. 833, 157 FERC ¶ 61,123 at P 39.

[58] FAST Act, Pub. L. No. 114-94, section 61,003, 129 Stat. 1312, 1776.

[59] Order No. 833, 157 FERC ¶ 61,123 at P 39 (citing NOPR, 155 FERC ¶ 61,278 at P 16 n.12).

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The Commission orders:

EEI's request for clarification is hereby granted in part and EEI's request for rehearing is denied, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)

RM16-15-001.DOCX.....1-17

163 FERC ¶ 61,094
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

North American Electric Reliability Corporation, Midwest Reliability Organization, and SERC Reliability Corporation — Docket No. RR18-3-000

ORDER GRANTING APPROVALS IN CONNECTION WITH THE DISSOLUTION OF THE SOUTHWEST POWER POOL REGIONAL ENTITY

(Issued May 4, 2018)

1. On March 5, 2018, the North American Electric Reliability Corporation (NERC), Midwest Reliability Organization (MRO), and SERC Reliability Corporation (SERC) (collectively, Petitioners) filed a joint petition requesting certain Commission approvals in connection with the dissolution of the Southwest Power Pool Regional Entity (SPP RE) and the transfer of registered entities within the SPP RE footprint to MRO and SERC (Joint Petition). Specifically, Petitioners seek Commission approval, in accordance with section 215(e)(4) of the Federal Power Act (FPA) and section 39.8 of the Commission's regulations, of (1) the termination of the Amended and Restated Delegation Agreement (Regional Delegation Agreement) between NERC and Southwest Power Pool, Inc. (SPP),[1] pursuant to the terms of a proposed Termination Agreement (Termination Agreement); (2) a proposal to transfer the registered entities within SPP RE to MRO and SERC; and (3) revisions to the Regional Delegation Agreements between NERC and MRO and between NERC and SERC to reflect the changed geographic footprints of MRO and SERC. In this order, we grant the requested approvals to reflect the dissolution of the SPP RE and the transfer of its registered entities to MRO and SERC, as discussed below.

[1] The proposed Termination Agreement provides that SPP RE is a division of SPP, a regional transmission organization (RTO). The Regional Delegation Agreement between NERC and SPP provides that SPP RE is an organization established to develop and enforce Reliability Standards within the geographic boundaries of SPP.

I. Background

2. On February 3, 2006, the Commission issued Order No. 672 as a first step in implementing the requirements of section 215 of the FPA governing electric reliability.[2] Among other things, Order No. 672 codified the criteria that an entity must satisfy to be certified as the Electric Reliability Organization (ERO), as well as the criteria under which the ERO may enter into an agreement to delegate authority to a Regional Entity.[3] On July 20, 2006, the Commission certified NERC as the ERO pursuant to FPA section 215(c), and accepted NERC's proposed *pro forma* delegation of certain ERO functions to its designated Regional Entities with the understanding that the document would undergo further modification as NERC entered into negotiations with candidate Regional Entities.[4]

3. In April 2007, NERC entered into separate Regional Delegation Agreements with eight Regional Entities, including the three Regional Entities at issue in this proceeding, SPP RE, MRO and SERC.[5] In those agreements, NERC delegated certain ERO functions to the Regional Entities, including the authority to audit, investigate, and otherwise ensure that users, owners, and operators of the Bulk-Power System comply with NERC's mandatory Reliability Standards, all subject to ERO oversight. Since then, the Commission has approved revised Regional Delegation Agreements between NERC and the Regional Entities, including with SPP RE, MRO and SERC.[6]

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[2] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[3] *See* 18 C.F.R. §§ 39.3, 39.8 (2017).

[4] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, (ERO Certification Order), *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *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).

[5] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh'g*, 120 FERC ¶ 61,260 (2007).

[6] *See North American Electric Reliability Corp.*, 153 FERC ¶ 61,135 (2015); *see also North American Electric Reliability Corp.*, 133 FERC ¶ 61,061 (2010), *order denying reh'g*, 134 FERC ¶ 61,179 (2011) (March 2011 Order).

II. Joint Petition

4. In the March 5, 2018 Joint Petition, Petitioners state that NERC and SPP mutually agreed in July 2017 to terminate the responsibilities of the SPP RE as a NERC Regional Entity. Petitioners state that SPP's decision to dissolve the SPP RE function stemmed from the diverging footprints of SPP RE and SPP, and the strategic decision for SPP to focus on its core registered entity functions of reliability coordination, markets, and transmission planning. Petitioners explain that NERC and SPP entered into a Termination Agreement designed to set forth each party's obligations in support of the termination of the Regional Delegation Agreement between NERC and SPP and the transition of SPP's Delegated Authority in a manner that maintains reliability and enhances the efficiency of the ERO Enterprise.[7]

5. Under the Termination Agreement, NERC is responsible for, *inter alia*, identifying a transferee Regional Entity for each registered entity in the SPP RE footprint. SPP is responsible for transferring relevant files and documents pertaining to delegation-related activities to the transferee Regional Entities. SPP is also responsible for submitting certain financial information to NERC following termination of its Regional Entity activities, including a description of the re-allocation of monies from SPP RE's Commission-approved statutory budget towards the costs of the wind-down and dissolution of the SPP RE. Further, SPP must submit to NERC a reconciliation of SPP RE's actual expenses with its budgeted expenses for 2018.

6. Petitioners state that SPP RE anticipates that it can address transitional and wind-down costs using its approved 2018 statutory assessment funding. Petitioners state that, following the termination of the Regional Delegation Agreement between NERC and SPP, any funds in excess of SPP RE's statutory assessments over statutory expenditures and reserves will be transferred to MRO and SERC, and will be allocated on the basis of the relative net energy for load (NEL) of the load-serving entities (LSEs) transferred to each of MRO and SERC. To the extent required, NERC requests the Commission's approval to deviate from the application of penalty monies as specified in Rule 1107 of the NERC Rules of Procedure, in order to allow SPP RE to apply any penalty funds it

[7] The Termination Agreement defines "SPP Delegated Authority" as SPP RE's "responsibilities and activities as a Regional Entity set forth in the [Regional Delegation Agreement]." Joint Petition, Att. 1 at 1.

received or receives on or after July 1, 2017 to its wind-down activities, or to transfer any remaining unused penalty collections to MRO and SERC.[8]

7. Petitioners state that the NERC Rules of Procedure do not contain specific criteria for the transfer to other Regional Entities of multiple registered entities in the event of a Regional Entity dissolution. However, Petitioners indicate that NERC was informed by the criteria in section 1208 of its Rules of Procedure in proposing revised boundaries for MRO and SERC. Petitioners state that those criteria call for the evaluation of the location of relevant facilities in relation to the geographic and electric boundaries of the transferee Regional Entity, the impact of the proposed transfer on other owners, operators, and users of the Bulk-Power System, and the impact of the proposed transfer on the current and future staffing, resources, budgets, and assessments of the transferee Regional Entity. Petitioners state that the proposed transfers of registered entities are consistent with the Commission's general guidance regarding changes in a Regional Entity's boundary, in which the Commission has noted that such changes "should be carefully considered and should serve to improve the effectiveness or efficiency of the Regional Entity's and NERC's administration of reliability, and should not merely benefit an individual registered entity."[9]

8. In evaluating where each registered entity should be assigned, NERC determined that the effectiveness and efficiency of the ERO Enterprise's administration of reliability would be best served by placing transmission paths within common Regional Entity boundaries. NERC excluded two of the four Regional Entities with which SPP RE has a geographic boundary, Western Electricity Coordinating Council and Texas Reliability Entity, because they are in different interconnections than the entities in SPP RE, leaving MRO and SERC as potential transferee Registered Entities. Ultimately, after performing a transmission corridor analysis and considering the functional relationships between registered entities, NERC proposed to transfer 109 SPP RE registered entities to MRO

[8] 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.

[9] Joint Petition at 12 (quoting *North American Electric Reliability Corp.*, 133 FERC ¶ 61,061 at P 72).

and 14 to SERC, with one entity to be registered in both MRO and SERC. NERC posted the proposed transfer assignments for stakeholder comment.

9. Petitioners indicate that both MRO and SERC expect to be able to integrate the transferred SPP RE entities with limited increases in administrative (indirect) costs. With respect to additional program resources (*e.g*. Compliance Monitoring and Enforcement, Reliability Assessment, Event Analysis and Training and Education), MRO expects to add up to 12 full-time equivalent staff members (FTEs) and SERC expects to add up to 4 FTEs, both by 2019. Neither MRO nor SERC anticipate the need for additional assessment funding for 2018, with any additional funds needed expected to come from existing working capital, operating reserves, or existing lines of credit. NERC projects that the existing LSEs in MRO will see a decrease in assessments in 2019 on a per-MWh of NEL basis, and that SERC LSEs will see little or no impact in assessments in 2019 as a result of the addition of the SPP RE registered entities.

10. With respect to the transfer of compliance monitoring and enforcement activities, NERC indicates that it believes the risk of any material gaps in oversight due to the transfer has been mitigated, in part, due to the transfer to MRO and SERC of compliance history data and the planned increases in FTEs.

11. Petitioners state that the only changes being proposed to the existing Regional Delegation Agreements between NERC and MRO and between NERC and SERC are to their respective Exhibit As, which describe the regional boundaries of MRO and SERC, to reflect the transfers of the SPP RE registered entities.

12. Petitioners note that SERC is currently the Compliance Enforcement Authority responsible for compliance monitoring and enforcement with respect to SPP's registered functions as an RTO. Petitioners state that, as part of the dissolution of SPP RE and related transfers described in the Joint Petition, NERC will act as the Compliance Enforcement Authority for SPP for two years following the termination of the Regional Delegation Agreement between NERC and SPP in order to facilitate the transition from SERC as the Compliance Enforcement Authority for the registered functions of SPP.[10]

13. Petitioners request that the transfers of registered entities to MRO and SERC become effective as of July 1, 2018. To allow time for additional wind-down activities by SPP RE, including the transfer of files, documents, and other accounting related matters, Petitioners request that the termination of the Regional Delegation Agreement between NERC and SPP become effective as of August 31, 2018.

[10] In addition, SPP, which is currently registered in MRO, WECC and SERC, will be deregistered in SERC as of the termination of the Compliance Monitoring and Enforcement Program Agreement between SERC and SPP (SERC-SPP CMEP Agreement).

III. Notice and Responsive Pleadings

14. Notice of Petitioners' March 5, 2018 filing was published in the *Federal Register*, 83 Fed. Reg. 10,715 (2018), with interventions and protests due on or before March 26, 2018. SPP, Westar Energy, Inc., American Public Power Association, and Golden Spread Electric Cooperative, Inc. filed timely motions to intervene. AE Power Services, LLC, Flat Ridge Wind Energy, LLC, and Flat Ridge 2 Wind Energy LLC filed a timely joint motion to intervene. Southwestern Power Administration filed an out-of-time motion to intervene. Sunflower Electric Power Corporation and Mid-Kansas Electric Company, Inc. filed an out-of-time joint motion to intervene. No comments or protests were filed.

15. The timely, unopposed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2018). Given the early stage of this proceeding, we also grant the untimely motions to intervene.

IV. Discussion

16. As discussed below, we grant the requested approvals to reflect the dissolution of the SPP RE and the transfer of its registered entities to MRO and SERC. We find that Petitioners have demonstrated that the proposal, including changes to the MRO and SERC Delegation Agreements to reflect the transfers of registered entities, will "promote effective and efficient administration of bulk-power system reliability," in accordance with FPA section 215(e)(4).[11]

17. We find that NERC's approach applying the criteria in section 1208 of NERC's Rules of Procedure is appropriate for evaluating the proposed dissolution. NERC's assessment of how to allocate the registered entities amongst the two Regional Entities is consistent with the criteria in section 1208 governing individual requests to change a Regional Entity boundary, and with applicable Commission precedent. In particular, in the March 2011 Order, the Commission found that "it is clear that the [s]ection 1208 criteria are designed to promote effective and efficient administration of Bulk-Power System reliability,"[12] and we find that NERC appropriately considered these criteria to determine that the registered entities within SPP RE should be transferred to MRO and SERC. Among other things, NERC found that it was appropriate to assign the entities amongst MRO and SERC, given that they are the only two Regional Entities within the same interconnection that share a geographic boundary with SPP RE. We are satisfied

[11] *See* 16 U.S.C. § 824o(e)(4) (2012) (the ERO may enter into an agreement to delegate authority to a regional entity if, *inter alia*, "the agreement promotes effective and efficient administration of bulk-power system reliability").

[12] March 2011 Order, 134 FERC ¶ 61,179 at P 9.

that Petitioners and SPP have considered and established mechanisms to mitigate against the risk of material gaps in oversight of compliance and enforcement activities due to the transfer of registered entities, including (1) adding FTEs to accommodate increased workload, (2) assessing that MRO and SERC have sufficient funds available through existing working capital and operating reserves and respective lines of credit, (3) taking measures to ensure a seamless transfer of compliance history from SPP RE to MRO and SERC, (4) ensuring that certain previously-scheduled audits are performed, and (5) reviewing the audit schedule for other SPP RE registered entities to assess and to identify any areas of risks that would warrant audits in 2018.[13] Accordingly, we approve the Joint Petition's proposal to terminate the Regional Delegation Agreement between NERC and SPP, effective August 31, 2018, in accordance with the terms of the Termination Agreement, and to transfer the registered entities within SPP RE to MRO and SERC, effective July 1, 2018, as requested. We also approve the proposed revisions to the Regional Delegation Agreements between NERC and MRO and between NERC and SERC to reflect the change in regional boundaries due to the transfer of SPP RE registered entities to MRO and SERC.

18. Petitioners state that, in 2010, the Commission approved SERC as the Compliance Enforcement Authority for the registered functions of SPP in the SPP RE footprint in accordance with the SERC-SPP CMEP Agreement.[14] Petitioners state that to facilitate the transition from SERC as the Compliance Enforcement Authority for the registered functions of SPP, NERC will act as the Compliance Enforcement Authority for SPP for two years following the termination of the Regional Delegation Agreement between NERC and SPP.[15] We find that NERC's transition plan is reasonable and consistent with NERC's enforcement authority and expect NERC to notify the Commission prior to the end of the two-year period to explain if NERC will continue its role as Compliance Enforcement Authority, or if another entity will assume that role.[16]

19. NERC also requests Commission approval to deviate from the requirements of Section 1107 of the NERC Rules of Procedure to allow SPP RE to apply any penalty funds to its wind-down activities, or to transfer any remaining unused penalties to MRO

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[13] *See* Joint Petition at 16-19.

[14] Joint Petition at 22 (*citing North American Electric Reliability Corp.*, 132 FERC ¶ 61,024; *order granting reh'g*, 133 FERC ¶ 61,190 (2010).

[15] Joint Petition at 22.

[16] NERC, as the ERO, retains authority under FPA section 215(e) to act as the Compliance Enforcement Authority over any user, owner, or operator of the Bulk-Power System. *See, e.g.*, Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 654.

and SERC, rather than using such funds to offset SPP RE's budget for the next year.[17] We find that NERC's request is appropriate, in light of the dissolution of SPP RE, and is consistent with section 1107.4 of the NERC Rules of Procedure, which allows Regional Entities to obtain a waiver of this requirement, if approved.[18] Accordingly, we approve the request to deviate from section 1107 of the NERC Rules of Procedure, to the extent necessary, to allow SPP to use penalty funds received on or after July 1, 2017 for its wind-down activities and to transfer any remaining unused penalty funds to MRO and SERC in accordance with the Termination Agreement.

The Commission orders:

(A) Petitioners' proposal to terminate the Regional Delegation Agreement between NERC and SPP and to transfer the registered entities within SPP RE to MRO and SERC, both in accordance with the terms of the Termination Agreement, are hereby approved, as discussed in the body of this order.

(B) Petitioners' proposed revisions to the Regional Delegation Agreement between NERC and MRO and to the Regional Delegation Agreement between NERC and SERC are hereby approved, as discussed in the body of this order.

(C) NERC's request to deviate from section 1107 of the NERC Rules of Procedure is hereby approved, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[17] Joint Petition at 10-11.

[18] Section 1107.4 of the NERC Rules of Procedure provides that "[e]xceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by [the Commission]."

163 FERC ¶ 61,032
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM17-11-000; Order No. 843]

Revised Critical Infrastructure Protection Reliability Standard CIP-003-7 – Cyber Security – Security Management Controls

(Issued April 19, 2018)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) approves Critical Infrastructure Protection (CIP) Reliability Standard CIP-003-7 (Cyber Security – Security Management Controls), submitted by the North American Electric Reliability Corporation (NERC). Reliability Standard CIP-003-7 clarifies the obligations pertaining to electronic access control for low impact BES Cyber Systems; requires mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems; and requires responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems. In addition, the Commission directs NERC to develop modifications to the CIP Reliability Standards to mitigate the risk of malicious code that could result from third-party transient electronic devices.

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

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

163 FERC ¶ 61,032
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Revised Critical Infrastructure Protection Reliability Standard CIP-003-7 – Cyber Security – Security Management Controls	Docket No. RM17-11-000

ORDER NO. 843

FINAL RULE

(Issued April 19, 2018)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission approves Reliability Standard CIP-003-7 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. Reliability Standard CIP-003-7 addresses the Commission's directives from Order No. 822 and is an improvement over the current Commission-approved CIP Reliability Standards.[2] Specifically, Reliability Standard CIP-003-7 improves upon the existing Reliability Standards by: (1) clarifying the obligations pertaining to electronic access control for low impact BES Cyber Systems;[3]

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

[2] *Revised Critical Infrastructure Protection Reliability Standards*, Order No. 822, 154 FERC ¶ 61,037, *reh'g denied,* Order No. 822-A, 156 FERC ¶ 61,052 (2016).

[3] BES Cyber System is defined by NERC as "[o]ne or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a

(2) adopting mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems; and (3) requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems. We also approve NERC's proposed implementation plan and violation risk factor and violation severity level assignments. Finally, we approve NERC's proposed revised definitions for inclusion in the NERC Glossary.

2. In the NOPR, the Commission proposed to direct that NERC modify Reliability Standard CIP-003-7 to: (1) provide clear, objective criteria for electronic access controls for low impact BES Cyber Systems; and (2) address the need to mitigate the risk of malicious code that could result from third-party transient electronic devices.[4] The Commission adopts the NOPR proposal regarding third-party transient electronic devices but does not adopt the proposal regarding criteria for electronic access controls for low impact BES Cyber Systems.

functional entity." Glossary of Terms Used in NERC Reliability Standards (NERC Glossary). The acronym BES refers to the bulk electric system. Reliability Standard CIP-002-5.1a (Cyber Security System Categorization) provides a "tiered" approach to cybersecurity requirements, based on classifications of high, medium and low impact BES Cyber Systems.

[4] *Revised Critical Infrastructure Protection Reliability Standard CIP-003-7 – Cyber Security – Security Management Controls*, Notice of Proposed Rulemaking, 82 FR 49541 (Oct. 26, 2017), 161 FERC ¶ 61,047 (2017) (NOPR).

3. As discussed below, in view of the comments from NERC and others, we are persuaded that Reliability Standard CIP-003-7 provides a clear security objective that establishes compliance expectations. Accordingly, we do not adopt the proposed directive relating to electronic access controls for low impact BES Cyber Systems. Instead, as suggested in the comments, we direct NERC to conduct a study to assess the implementation of Reliability Standard CIP-003-7 to determine whether the electronic access controls adopted by responsible entities provide adequate security. NERC must submit the directed study within eighteen months of the effective date of Reliability Standard CIP-003-7.

4. With regard to the second issue discussed in the NOPR, we remain concerned that the proposed Reliability Standard lacks a clear requirement to mitigate the risk of malicious code that could result from third-party transient electronic devices. Accordingly, we direct NERC to develop a modification to the Reliability Standard to provide the needed clarity. Such modification will better ensure that registered entities clearly understand their mitigation obligations and, thus, improve individual entity mitigation plans and collectively improve the cybersecurity posture of the electric grid.

I. Background

A. Section 215 and Mandatory Reliability Standards

5. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Reliability Standards may be enforced by the ERO,

subject to Commission oversight, or by the Commission independently.[5] Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[6] and subsequently certified NERC.[7]

B. Order No. 822

6. The Commission approved the "Version 1" CIP Reliability Standards in January 2008, and subsequently acted on revised versions of the CIP Reliability Standards.[8] On January 21, 2016, in Order No. 822, the Commission approved seven CIP Reliability Standards: CIP-003-6 (Security Management Controls), CIP-004-6 (Personnel and Training), CIP-006-6 (Physical Security of BES Cyber Systems), CIP-007-6 (Systems Security Management), CIP-009-6 (Recovery Plans for BES Cyber Systems), CIP-010-2 (Configuration Change Management and Vulnerability Assessments), and CIP-011-2 (Information Protection). The Commission determined that the Reliability Standards

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

[6] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

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

[8] *Mandatory Reliability Standards for Critical Infrastructure Protection*, Order No. 706, 122 FERC ¶ 61,040, *order on reh'g*, Order No. 706-A, 123 FERC ¶ 61,174 (2008), *order on clarification*, Order No. 706-B, 126 FERC ¶ 61,229 (2009), *order on clarification*, Order No. 706-C, 127 FERC ¶ 61,273 (2009); *Version 5 Critical Infrastructure Protection Reliability Standards*, Order No. 791, 145 FERC ¶ 61,160 (2013), *order on clarification and reh'g*, Order No. 791-A, 146 FERC ¶ 61,188 (2014).

under consideration at that time were an improvement over the prior iteration of the CIP Reliability Standards and addressed the directives in Order No. 791 by, among other things, addressing in an equally effective and efficient manner the need for a NERC Glossary definition for the term "communication networks" and providing controls to address the risks posed by transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at high and medium impact BES Cyber Systems.[9]

7. In addition, in Order No. 822, pursuant to section 215(d)(5) of the FPA, the Commission directed NERC, *inter alia*, to: (1) develop modifications to the Low Impact External Routable Connectivity (LERC) definition to eliminate ambiguity surrounding the term "direct" as it is used in the LERC definition; and (2) develop modifications to the CIP Reliability Standards to provide mandatory protection for transient electronic devices used at low impact BES Cyber Systems.[10]

C. NERC Petition

8. On March 3, 2017, NERC submitted a petition seeking approval of Reliability Standard CIP-003-7 and the associated violation risk factors and violation severity levels, implementation plan and effective date. NERC states that Reliability Standard CIP-003-7 satisfies the criteria set forth in Order No. 672 that the Commission applies when

[9] Order No. 822, 154 FERC ¶ 61,037 at P 17.

[10] *Id.* P 18.

reviewing a proposed Reliability Standard.[11] NERC also sought approval of revisions to NERC Glossary definitions for the terms Removable Media and Transient Cyber Asset, as well as the retirement of the NERC Glossary definitions of LERC and Low Impact BES Cyber System Access Point (LEAP). In addition, NERC proposed the retirement of Commission-approved Reliability Standard CIP-003-6.[12]

9. NERC states that Reliability Standard CIP-003-7 improves upon the existing protections that apply to low impact BES Cyber Systems. NERC avers that the proposed modifications address the Commission's directives from Order No. 822 by: (1) clarifying electronic access control requirements applicable to low impact BES Cyber Systems; and (2) adding requirements for the protection of transient electronic devices used for low impact BES Cyber Systems. In addition, while not required by Order No. 822, NERC proposes a CIP Exceptional Circumstances policy for low impact BES Cyber Systems.

10. In response to the Commission's directive to develop modifications to eliminate ambiguity surrounding the term "direct" as it is used in the LERC definition, NERC proposes to: (1) retire the terms LERC and LEAP from the NERC Glossary; and (2) modify Section 3 of Attachment 1 to Reliability Standard CIP-003-7 "to more clearly

[11] *See* NERC Petition at 2 (citing Order No. 672, FERC Stats. & Regs. ¶ 31,204 at PP 262, 321-337); *id.*, Exhibit D (Order No. 672 Criteria).

[12] Reliability Standard CIP-003-7 is not attached to this Final Rule. The Reliability Standard is available on the Commission's eLibrary document retrieval system in Docket No. RM17-11-000 and is posted on the NERC website, http://www.nerc.com.

delineate the circumstances under which Responsible Entities must establish access controls for low impact BES Cyber Systems."[13] NERC states that the proposed revisions are designed to simplify the electronic access control requirements associated with low impact BES Cyber Systems to avoid ambiguities associated with the term "direct." NERC explains that it recognized the "added layer of unnecessary complexity" introduced by distinguishing between "direct" and "indirect" access within the LERC definition and asserts that the proposed revisions will "help ensure that Responsible Entities implement the required security controls effectively."[14]

11. With regard to the Commission's directive that NERC develop modifications to the CIP Reliability Standards to provide mandatory protection for transient electronic devices used at low impact BES Cyber Systems, NERC proposes to add a new section to Attachment 1 of Reliability Standard CIP-003-7 that requires responsible entities to include controls in their cyber security plans to mitigate the risk of the introduction of malicious code to low impact BES Cyber Systems that could result from the use of "Transient Cyber Assets or Removable Media." Specifically, proposed Section 5 of Attachment 1 lists controls to be applied to Transient Cyber Assets and Removable Media that NERC contends "will provide enhanced protections against the propagation of malware from transient devices."[15]

[13] NERC Petition at 16.

[14] *Id.* at 16.

[15] *Id.* at 26-27.

12. NERC also proposes a modification that was not directed by the Commission in Order No. 822. Namely, NERC proposes revisions in Requirement R1 of Reliability Standard CIP-003-7 to require responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems.[16] NERC states that a number of requirements in the existing CIP Reliability Standards specify that responsible entities do not have to implement or continue implementing these requirements to avoid hindering the entities' ability to timely and effectively respond to the CIP Exceptional Circumstance. NERC proposes to add a requirement for responsible entities to have a CIP Exceptional Circumstances policy that applies to low impact BES Cyber Systems since the proposed requirements relating to transient electronic devices used at low impact BES Cyber Systems include an exception for CIP Exceptional Circumstances.[17]

13. NERC requests that Reliability Standard CIP-003-7 and the revised definitions of Transient Cyber Asset and Removable Media become effective the first day of the first calendar quarter that is eighteen months after the effective date of the Commission's order approving the Reliability Standard.

[16] A CIP Exceptional Circumstance is defined in the NERC Glossary as a situation that involves or threatens to involve one or more of the following, or similar, conditions that impact safety or bulk electric system reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a Cyber Security Incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability.

[17] NERC Petition at 31-32.

D. Notice of Proposed Rulemaking

14. On October 19, 2017, the Commission issued a NOPR that proposed to approve Reliability Standard CIP-003-7. The NOPR proposed to determine that Reliability Standard CIP-003-7 is just, reasonable, not unduly discriminatory or preferential, and in the public interest and addresses the directives in Order No. 822 by: (1) clarifying the obligations pertaining to electronic access control for low impact BES Cyber Systems; and (2) adopting mandatory security controls for transient electronic devices used at low impact BES Cyber Systems. In addition, the NOPR observed that, by requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances for low impact BES Cyber Systems, Reliability Standard CIP-003-7 would align the treatment of low impact BES Cyber Systems with that of high and medium impact BES Cyber Systems, which currently include a requirement for declaring and responding to CIP Exceptional Circumstances. Therefore, the Commission proposed to approve Reliability Standard CIP-003-7 because the proposed modifications improve the base-line cybersecurity posture of responsible entities compared to the current Commission-approved CIP Reliability Standards.

15. In addition, the Commission proposed to direct that NERC develop modifications to Reliability Standard CIP-003-7 to addressed two issues: (1) provide clear, objective criteria for electronic access controls for low impact BES Cyber Systems; and (2) address the need to mitigate the risk of malicious code that could result from third-party transient electronic devices. The Commission explained that modifications directed at these two

concerns will address potential gaps and improve the cyber security posture of responsible entities that must comply with the CIP Reliability Standards.

16. The Commission received comments in response to the NOPR from Jonathan Appelbaum (Appelbaum), Electric Consumers Resource Council (ELCON), North American Electric Reliability Corporation (NERC), Transmission Access Policy Study Group (TAPS), and Trade Associations.[18] We address below the issues raised in the NOPR and comments.

II. Discussion

17. Pursuant to section 215(d)(2) of the FPA, we approve Reliability Standard CIP-003-7 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. Reliability Standard CIP-003-7 addresses the directives in Order No. 822 and is an improvement over the currently-effective, Commission-approved CIP Reliability Standards. Specifically, Reliability Standard CIP-003-7 improves upon the existing CIP Reliability Standards by: (1) clarifying the obligations pertaining to electronic access control for low impact BES Cyber Systems; (2) adopting mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems; and (3) requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems. We also approve NERC's proposed implementation plan and violation risk factor and

[18] Trade Associations represent American Public Power Association, Edison Electric Institute, and National Rural Electric Cooperative Association.

violation severity level assignments. Finally, we approve NERC's proposed revised definitions for inclusion in the NERC Glossary.

18. In addition, as discussed below, pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop modifications to the CIP Reliability Standards to mitigate the risk of malicious code that could result from third-party transient electronic devices. However, for the reasons discussed below, we determine not to adopt the NOPR proposal to direct NERC to develop criteria for electronic access controls for low impact BES Cyber Systems at this time.

19. Below, we discuss the following matters: (A) criteria for electronic access controls for low impact BES Cyber Systems; (B) mitigation of the risk of malicious code associated with third-party transient electronic devices; and (C) implementation plan and effective date.

A. Criteria for Electronic Access Controls for Low Impact BES Cyber Systems

1. NOPR

20. In the NOPR, the Commission proposed to direct NERC to develop modifications to Section 3 of Attachment 1 to Reliability Standard CIP-003-7 to provide clear, objective criteria for electronic access controls for low impact BES Cyber Systems.[19] Specifically, the proposed directive addressed the concern that Reliability Standard CIP-003-7 may not provide adequate electronic access controls for low impact BES Cyber Systems because Reliability Standard CIP-003-7 does not provide clear, objective criteria or measures to

[19] NOPR, 161 FERC ¶ 61,047 at P 32.

assess compliance by independently confirming that the access control strategy adopted by a responsible entity would reasonably meet the security objective of permitting only "necessary inbound and outbound electronic access" to its low impact BES Cyber Systems.[20] The Commission stated that, in order to ensure an objective and consistently-applied requirement, the electronic access control plan required in Attachment 1 should require the responsible entity to articulate its access control strategy for a particular set of low impact BES Cyber Systems and provide a technical rationale rooted in security principles explaining how that strategy will reasonably restrict electronic access. In addition, the Commission stated that Attachment 1 should outline basic security principles in order to provide clear, objective criteria or measures to assist in assessing compliance.[21]

21. The Commission observed that without clear, objective criteria or measures, auditors will not necessarily have adequate information to assess the reasonableness of the responsible entity's decision with respect to how the responsible entity identified necessary communications or restricted electronic access to specific low impact BES Cyber Systems. The Commission posited that absent such information, it is possible that an auditor could assess a violation where an entity adequately protected its low impact

[20] *Id.* P 28.

[21] *Id.* P 29.

BES Cyber Systems or fail to recognize a situation where additional protections are necessary to meet the security objective of the Reliability Standard.[22]

2. Comments

22. NERC acknowledges the NOPR concerns but comments that a directive "may not be necessary."[23] Specifically, NERC asserts that "Responsible Entities must provide auditors sufficient information to allow the auditors to properly assess compliance with section 3.1" of Reliability Standard CIP-003-7.[24] NERC contends that Section 3.1 "articulates a clear security objective: permit only necessary inbound and outbound access to low impact BES Cyber Systems."[25] NERC explains that Section 3.1 is not prescriptive due to the wide array of low impact BES Cyber Systems and their lower risk to bulk electric system reliability, but, while Section 3.1 grants responsible entities flexibility, "a Responsible Entity must demonstrate that its electronic access permissions and controls are consistent with the security objective."[26] Specifically, NERC maintains that a responsible entity "must document the necessity of its inbound and outbound electronic access permissions and provide justification of the need for such access."[27]

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[22] *Id.*

[23] NERC Comments at 3.

[24] *Id.* (citing NERC Petition at 21-24).

[25] *Id.*

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

[27] *Id.* at 4 (citing NERC Petition at 22).

NERC states further that "[i]f a Responsible Entity fails to articulate a reasonable business or operational need for the electronic access permission, the ERO Enterprise would find that the Responsible Entity did not comply with Section 3.1."[28] NERC continues that "[c]onsistent with the intent of the Commission's proposed directive, the Responsible Entity would have to articulate its access control strategy for the low impact BES Cyber System and provide a technical rationale rooted in security principles, explaining how that strategy will reasonably restrict electronic access."[29] NERC states that if a responsible entity "fails to demonstrate that its chosen electronic access controls are properly designed and implemented to meet the security objective, the ERO Enterprise would find that the Responsible Entity did not comply with Section 3.1" of Reliability Standard CIP-003-7.[30]

23. NERC concludes that while the Commission's proposed directive may not be necessary and could potentially be an inefficient use of NERC and industry resources, "[a]rticulating objective criteria for electronic access controls for low impact BES Cyber Systems may improve clarity and auditability, and help ensure that entities implement effective electronic access controls."[31]

24. Trade Associations, TAPS and ELCON do not support the proposed directive, claiming that the proposal would impose additional burdens on registered entities without

[28] *Id.*

[29] *Id.*

[30] *Id.*

[31] *Id.* at 5.

a corresponding reliability benefit. Trade Associations and TAPS contend that Section 3 of Attachment 1 to Reliability Standard CIP-003-7 gives responsible entities needed flexibility to develop and implement effective electronic access controls for low impact BES Cyber Systems. TAPS adds that Reliability Standard CIP-003-7 reflects what NERC, through the standard development process, "determined was a technically appropriate tailoring of electronic access controls requirements to low impact BES cyber systems."[32] Trade Associations recommend, as an alternative to the proposed directive, that the Commission approve the proposed Reliability Standard without modification and monitor its concerns, for example, by directing NERC to conduct a study to assess the implementation by responsible entities of Reliability StandardCIP-003-7 electronic access controls to determine whether there are in fact inadequate controls. According to Trade Associations, a fact-driven assessment would help to inform and demonstrate a reliability and security need for future Commission actions related to the CIP Reliability Standards.[33]

25. Further, Trade Associations assert that a risk-based approach is essential to allow responsible entities to focus their resources on assets that have a higher impact on bulk electric system reliability. ELCON adds that while it "appreciates the value establishing more tangible criteria for adequate Low-Impact BES Cyber System controls, … the

[32] TAPS Comments at 7 (*citing* 16 U.S.C. 824o(d)).

[33] Trade Associations Comments at 9.

additional requirements that the Commission proposes would do nothing to harden a Low-Impact facility against the rapid evolution in cyber warfare."[34]

26. Appelbaum supports the proposed directive regarding Section 3 of Attachment 1 to Reliability Standard CIP-003-7. Appelbaum notes that Reliability Standard CIP-003-7 "leaves the choice of controls to the [responsible entity] and leaves an Auditor with no requirement basis to perform an audit."[35] Appelbaum states that under "NERC's proposal that each entity establishes their own security plan and only needs to demonstrate compliance and adherence to its plan then … the implementation of security controls will be implemented to various levels of security and differentiated … across the NERC Regions."[36] Appelbaum states further that Reliability Standard CIP-003-7 "will result in different auditor conclusions for similarly situated entities implementing similar protections."[37] Appelbaum concludes that "[c]lear requirements are needed to establish a common understanding of the necessary security to be achieved."[38]

3. Commission Determination

27. We do not to adopt the proposed directive, but rather adopt the Trade Associations' recommendation for a study and report to be filed with the Commission. We are satisfied with the explanation of NERC and other commenters that Section 3 of

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[34] ELCON Comments at 4.

[35] Applebaum Comments at 5.

[36] *Id.* at 6.

[37] *Id.* at 7.

[38] *Id.*

Attachment 1 to Reliability Standard CIP-003-7 provides a clear security objective that establishes compliance expectations. Specifically, we are persuaded by commenters that Section 3 of Attachment 1 requires responsible entities to adopt security controls to permit only necessary inbound and outbound electronic access to Cyber Assets connected using a routable protocol to low impact BES Cyber Systems.

28. The concern raised in the NOPR focused on the lack of clear, objective criteria or measures to assess compliance with Reliability Standard CIP-003-7. As noted above, however, NERC states in its comments that responsible entities will be required to demonstrate that electronic access permissions and controls associated with low impact BES Cyber Systems are consistent with the stated security objective. NERC also clarifies that responsible entities will be required to "document the [business or operational] necessity of its inbound and outbound electronic access permissions and provide justification of the need for such access."[39] Given NERC's statements, we believe that there will be adequate measures to assess compliance with Reliability Standard CIP-003-7. We expect responsible entities to be able to provide a technically sound explanation as to how their electronic access controls meet the security objective.

29. In response to Appelbaum's comment that auditors will not have a common understanding on which to judge compliance across the ERO enterprise, in view of NERC's comments, we believe that NERC and the Regional Entities will have the ability

[39] NERC Comments at 4.

to assess the effectiveness of a responsible entity's electronic access control plan as well as a responsible entity's adherence to its electronic access control plan.

30. Moreover, to ensure that the security controls are implemented and that Section 3 accomplishes its intended purpose, we adopt Trade Associations' proposal and direct NERC to conduct a study to assess the implementation of Reliability Standard CIP-003-7.[40] The study should address what electronic access controls entities choose to implement and under what circumstances, and whether the electronic access controls adopted by responsible entities provide adequate security, as well as other relevant information found by NERC as a result of the study. NERC must file the study within eighteen months of the effective date of Reliability Standard CIP-003-7. We may revisit the need for modifications to Section 3 of Attachment 1 to Reliability Standard CIP-003-7 if warranted by the study determination, or the results of audits or other compliance procedures.

B. Mitigation of the Risk of Malicious Code Associated with Third-Party Transient Electronic Devices

1. NOPR

31. In the NOPR, the Commission proposed to direct NERC to develop modifications to proposed Section 5 of Attachment 1 to Reliability Standard CIP-003-7 to mitigate the risk of malicious code that could result from third-party transient electronic devices.[41] Specifically, the Commission raised a concern that Reliability Standard CIP-003-7 does

[40] Trade Associations Comments at 9.

[41] *Id.* P 41.

not explicitly require mitigation of the introduction of malicious code from third-party managed transient electronic devices, even if the responsible entity determines that the third-party's policies and procedures are inadequate. The Commission noted NERC's statement in its petition that a responsible entity's failure to mitigate this risk "may not constitute compliance."[42] The Commission stated that NERC's explanation suggests that, with regard to low impact BES Cyber Systems, the requirement lacks an obligation for a responsible entity to correct any deficiencies that are discovered during a review of third-party transient electronic device management practices.

32. The Commission expressed concern that Reliability Standard CIP-003-7 may contain a reliability gap where a responsible entity contracts with a third-party but fails to mitigate potential deficiencies discovered in the third-party's malicious code detection and prevention practices prior to a transient electronic device being connected to a low impact BES Cyber System. The Commission explained that the reliability gap would result from the fact that Reliability Standard CIP-003-7 does not contain: (1) a requirement for the responsible entity to mitigate any malicious code found during the third-party review(s); or (2) a requirement that the responsible entity take reasonable steps to mitigate the risks of third party malicious code on its systems, if an arrangement cannot be made for the third-party to do so. The Commission observed that without such

[42] *Id.* P 39 (*citing* NERC Petition at 30).

obligations responsible entities could, without compliance consequences, simply accept the risk of deficient third-party transient electronic device management practices.[43]

33. Therefore, pursuant to section 215(d)(5) of the FPA, the Commission proposed to direct NERC to modify Reliability Standard CIP-003-7 to require responsible entities to implement controls to address the need to mitigate the risk of malicious code that could result from third-party transient electronic devices.

2. Comments

34. NERC states that it "agrees with the Commission that, should a Responsible Entity find that a third party's processes and practices for protecting its transient electronic devices inadequate, the Responsible Entity must be required to take mitigating action prior to connecting third-party transient electronic devices to a low impact BES Cyber System."[44] According to NERC, "failure to take mitigating action in this circumstance[] could result in a finding of noncompliance with Section 5 of Attachment 1."[45] NERC, therefore, asserts that "the proposed directive may not be necessary and may be an inefficient use of NERC and industry resources."[46] NERC observes, however, that

[43] *Id.* P 40 (*citing* Order No. 706, 122 FERC ¶ 61,040 at P 150 (rejecting the concept of acceptance of risk in the CIP Reliability Standards)).

[44] NERC Comments at 6 (citing NERC Petition at 29).

[45] *Id.*

[46] *Id.*

"[m]odifying proposed Section 5 to explicitly include a mitigation requirement for third-part[y] devices may remove any doubt about compliance expectations."[47]

35. Trade Associations and ELCON do not support the proposed directive. Trade Associations contend that "[a]lthough Section 5.2 [of Attachment 1 to CIP-003-7] does not explicitly require the responsible entity to mitigate the introduction of malicious code, risk mitigation is an explicit obligation under Section 5."[48] Trade Associations state that if a responsible entity's plan does not "achieve the objective of mitigating the risk of the introduction of malicious code to low impact BES Cyber Systems through the use of Transient Cyber Assets … then the plan will not comply with Section 5."[49] Trade Associations maintains that the "intent of the requirement is made clear in the Supplemental Material for Section 5 and 5.2, which both require the responsible entities to document how they will mitigate the introduction of malicious code."[50] Trade Associations note in a footnote that:

> Although the Supplemental Material does not create binding obligations on responsible entities, the text of the Supplemental Material in the Proposed Standard further clarifies and reinforces that the binding requirements found in CIP-003-7, Attachment 1, Section 5 include the obligation to take additional steps if a third-party's practices do not meet the security objective.[51]

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[47] *Id.*

[48] Trade Associations Comments at 10.

[49] *Id.* at 11.

[50] *Id.*

[51] *Id.*

Trade Associations conclude that the Commission should approve Reliability Standard CIP-003-7 without modification.

36. ELCON states that "the requirement for a Low-Impact BES Cyber System owner or operator to actively mitigate deficiencies in third party's anti-virus security programs does exist in [Section 5 of Attachment 1 to Reliability Standard CIP-003-7]."[52] ELCON states that the opening paragraph of Section 5, which requires responsible entities to implement one or more plans to "achieve the objective of mitigating the risk of the introduction of malicious code to low impact BES Cyber Systems through the use of Transient Cyber Assets or Removable Media," establishes an obligation to mitigate any identified deficiencies. ELCON contends that the objective of mitigating the risk "cannot be reached if the Responsible Entity allows a third party to connect an insufficiently evaluated [Transient Cyber Asset] to a Low-Impact BES Cyber System."[53] ELCON argues that the "positioning of the requirement in the opening paragraph of Section 5 assures that mitigating actions must be taken to address deficiencies detected" with responsible entity-owned Transient Cyber Assets, vendor-owned Transient Cyber Assets, and Removable Media.[54]

[52] ELCON Comments at 4 (emphasis in original).

[53] *Id.* at 4-5.

[54] *Id.* at 5.

3. Commission Determination

37. We adopt the NOPR proposal and, pursuant to section 215(d)(5) of the FPA, direct that NERC develop modifications to Reliability Standard CIP-003-7 to address our concern and ensure that responsible entities implement controls to mitigate the risk of malicious code that could result from third-party transient electronic devices. NERC could satisfactorily address the identified concern, for example, by modifying Section 5 of Attachment 1 to CIP-003-7 to clarify that responsible entities must implement controls to mitigate the risk of malicious code that could result from the use of third-party transient electronic devices.

38. The directed modification will improve the security posture of responsible entities by clarifying compliance expectations. While commenters claim that the provision is sufficiently clear and ask the Commission not to adopt the proposal, all commenters agree that there is not an explicit requirement to mitigate the threat of malicious code that could result from third-party transient electronic devices. While Trade Associations state that Section 5.2 of Attachment 1 does not explicitly require the mitigation of malicious code, Trade Associations and ELCON suggest that Section 5 generally requires risk mitigation. While commenters agree that, at least implicitly, the mitigation of malicious code is an obligation, the lack of a clear requirement could lead to confusion in both the development of a compliance plan and in the implementation of a compliance plan. In addition, although NERC contends that the proposed directive may not be necessary, NERC agrees that modifying Reliability Standard CIP-003-7 to address the mitigation of malicious code explicitly could clarify compliance obligations.

39. Therefore, pursuant to FPA section 215(d)(5), we direct NERC to develop and submit modifications to Reliability Standard CIP-003-7 to include an explicit requirement that responsible entities implement controls to mitigate the risk of malicious code that could result from third-party transient electronic devices.

C. Implementation Plan and Effective Date

NERC Petition

40. In its petition, NERC requests an effective date for Reliability Standard CIP-003-7 and the revised definitions of Transient Cyber Asset and Removable Media on the first day of the first calendar quarter that is eighteen months after the effective date of the Commission's order approving the Reliability Standard. NERC explains that the implementation plan does not alter the previously-approved compliance dates for Reliability Standard CIP-003-6 other than the compliance date for Reliability Standard CIP-003-6, Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003-7. NERC also proposes that the retirement of Reliability Standard CIP-003-6 and the associated definitions become effective on the effective date of Reliability Standard CIP-003-7.[55]

41. The NOPR proposed to approve NERC's implementation plan and effective date for Reliability Standard CIP-003-7. The Commission did not receive any comments regarding this aspect of the NOPR. Accordingly, we approve NERC's proposed implementation plan and effective date.

[55] *Id.*, Exhibit C (Implementation Plan).

III. Information Collection Statement

42. The FERC-725B information collection requirements contained in this Final Rule are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[56] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[57] 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.

43. The Commission bases its paperwork burden estimates on the changes in paperwork burden presented by the proposed revision to CIP Reliability Standard CIP-003-7 as compared to the current Commission-approved Reliability Standard CIP-003-6. The Commission has already addressed the burden of implementing Reliability Standard CIP-003-6.[58] As discussed above, the immediate rulemaking addresses three areas of modification to the CIP Reliability Standards: (1) clarifying the

[56] 44 U.S.C. 3507(d) (2012).

[57] 5 CFR 1320.11 (2017).

[58] *See* Order No. 822, 154 FERC ¶ 61,037 at PP 84-88.

obligations pertaining to electronic access control for low impact BES Cyber Systems; (2) adopting mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems; and (3) requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems.

44. The NERC Compliance Registry, as of September 2017, identifies approximately 1,320 U.S. entities that are subject to mandatory compliance with Reliability Standards. Of this total, we estimate that 1,100 entities will face an increased paperwork burden under Reliability Standard CIP 003-7, estimating that a majority of these entities will have one or more low impact BES Cyber Systems. Based on these assumptions, we estimate the following reporting burden:

RM17-11-000 Final Rule (Mandatory Reliability Standards for Critical Infrastructure Protection Reliability Standards)						
	Number of Respondents (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response[59] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**

[59] The loaded hourly wage figure (includes benefits) is based on the average of three occupational categories for 2016 found on the Bureau of Labor Statistics website (http://www.bls.gov/oes/current/naics2_22.htm):

Legal (Occupation Code: 23-0000): $143.68

Electrical Engineer (Occupation Code: 17-2071): $68.12

Office and Administrative Support (Occupation Code: 43-0000): $40.89

Create low impact TCA assets plan (one-time)[60]	1,100	1	1,100	20 hrs.; $1,680	6,875 hrs.; $1,848,000	$1,680
Updates and reviews of low impact TCA assets (ongoing)[61]	1,100	300[62]	330,000	1.5 hrs.[63]; $126	495,000 hrs.; $41,580,000	$37,800
Update/modify documentation to remove LERC and LEAP (one-time)[60]	1,100	1	1,100	20 hrs.; $1,680	6,875 hrs.; $1,848,000	$1,680
Update paperwork for access control implementation in Section 2[64] and Section 3[65] (ongoing)[61]	1,100	1	1,100	20 hrs.; $1,680	6,875 hrs.; $1,848,000	$1,680
TOTAL (one-time)[60]			**2,200**		**13,750 hrs.; $3,696,000**	
TOTAL (ongoing)[61]			**331,100**		**501,875 hrs.; $43,428,000**	

45. The following shows the annual cost burden for each group, based on the burden hours in the table above:

($143.68 + $68.12 + $40.89) ÷ 3 = $84.23. The figure is rounded to $84.00 for use in calculating wage figures in this NOPR.

[60] This one-time burden applies in Year One only.

[61] This ongoing burden applies in Year 2 and beyond.

[62] We estimate that each entity will perform 25 updates per month. 25 updates *12 months = 300 updates (i.e. responses) per year.

[63] The 1.5 hours of burden per response is comprised of three sub-categories:

Updates to managed low TCA assets: 15 minutes (0.25 hours) per response

Updates to unmanaged low TCA assets: 60 minutes (1 hour) per response

Reviews of low TCA applicable controls: 15 minutes (0.25 hours) per response.

[64] Physical Security Controls.

[65] Electronic Access Controls.

- Year 1: $3,696,000
- Years 2 and 3: $43,428,000
- The paperwork burden estimate includes costs associated with the initial development of a policy to address requirements relating to: (1) clarifying the obligations pertaining to electronic access control for low impact BES Cyber Systems; (2) adopting mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems; and (3) requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems. Further, the estimate reflects the assumption that costs incurred in year 1 will pertain to policy development, while costs in years 2 and 3 will reflect the burden associated with maintaining logs and other records to demonstrate ongoing compliance.

46. Title: Mandatory Reliability Standards, Revised Critical Infrastructure Protection Reliability Standards

Action: Revision to FERC-725B information collection.

OMB Control No.: 1902-0248.

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

Frequency of Responses: On Occasion.

Necessity of the Information: This Final Rule approves the requested modifications to Reliability Standards pertaining to critical infrastructure protection. As discussed above,

the Commission approves NERC's revised CIP Reliability Standard CIP-003-7 pursuant to section 215(d)(2) of the FPA because it improves upon the currently-effective suite of cyber security CIP Reliability Standards.

Internal Review: The Commission has reviewed the Reliability Standard and made a determination that its action is necessary to implement section 215 of the FPA.

47. 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].

48. 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, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, 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 RM17-11-000 and OMB Control Number 1902-0248.

IV. Regulatory Flexibility Act Analysis

49. The Regulatory Flexibility Act of 1980 (RFA) generally requires a description and analysis of Final Rules that will have significant economic impact on a substantial

number of small entities.[66] The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[67] 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).[68] Reliability Standard CIP-003-7 is expected to impose an additional burden on 1,100 entities[69] (reliability coordinators, generator operators, generator owners, interchange coordinators or authorities, transmission operators, balancing authorities, transmission owners, and certain distribution providers).

50. Of the 1,100 affected entities discussed above, we estimate that approximately 857 or 78 percent[70] of the affected entities are small. As discussed above, Reliability Standard CIP-003-7 enhances reliability by providing criteria against which NERC and the Commission can evaluate the sufficiency of an entity's electronic access controls for low impact BES Cyber systems, as well as improved security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems). We estimate that each of the

[66] 5 U.S.C. 601-12 (2012).

[67] 13 CFR 121.101 (2017).

[68] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77343 (Dec. 23, 2013).

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

[70] 77.95 percent.

857 small entities to whom the modifications to Reliability Standard CIP-003-7 applies will incur one-time costs of approximately $3,360 per entity to implement this standard, as well as the ongoing paperwork burden reflected in the Information Collection Statement (approximately $39,480per year per entity). We do not consider the estimated costs for these 857 small entities to be a significant economic impact.

51. Based on the above analysis, we certify that the approved Reliability Standard will not have a significant economic impact on a substantial number of small entities.

V. Environmental Analysis

52. 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.[71] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[72] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

VI. Document Availability

53. 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

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

[72] 18 CFR 380.4(a)(2)(ii) (2017).

(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.

54. 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.

VII. Effective Date and Congressional Notification

55. The Final Rule is effective [**INSERT DATE 60 days from publication in FEDERAL REGISTER**]. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory

Enforcement Fairness Act of 1996. This Final Rule is being submitted to the Senate, House, and Government Accountability Office.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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163 FERC ¶ 61,184
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM16-22-000; Order No. 847]

Coordination of Protection Systems for Performance During Faults and Specific Training for Personnel Reliability Standards

(Issued June 7, 2018)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) approves Reliability Standards PRC-027-1 (Coordination of Protection Systems for Performance During Faults) and PER-006-1 (Specific Training for Personnel) submitted by the North American Electric Reliability Corporation (NERC).

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

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

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163 FERC ¶ 61,184
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Coordination of Protection Systems for Performance During Faults and Specific Training for Personnel Reliability Standards

Docket No. RM16-22-000

ORDER NO. 847

FINAL RULE

(Issued June 7, 2018)

1. Pursuant to section 215 of the Federal Power Act (FPA), the Commission approves Reliability Standards PRC-027-1 (Coordination of Protection Systems for Performance During Faults) and PER-006-1 (Specific Training for Personnel).[1] The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted Reliability Standards PRC-027-1 and PER-006-1 for approval. As discussed below, we determine that Reliability Standard PRC-027-1, which is designed to maintain the coordination of protection systems installed to detect and isolate faults on bulk electric system elements, such that those protection systems operate in the intended sequence during faults, and PER-006-1, which

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

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is intended to ensure that personnel are trained on specific topics essential to reliability to perform or support real-time operations of the bulk electric system, improve upon the currently-effective Reliability Standards. In addition, based on the record before us, we do not adopt the NOPR proposal to direct NERC to modify Reliability Standard PRC-027-1 to require an initial protection system coordination study to ensure that applicable entities will perform (or have performed), as a baseline, a study demonstrating proper coordination of its protection systems.

2. The Commission also approves the associated violation risk factors, violation severity levels, implementation plans, and effective dates proposed by NERC for Reliability Standards PRC-027-1 and PER-006-1. The Commission further approves the retirement of currently-effective Reliability Standard PRC-001-1.1(ii) (System Protection Coordination) as proposed by NERC. Finally, the Commission approves new and revised definitions submitted by NERC for incorporation in the NERC Glossary for the following terms: (1) "protection system coordination study;" (2) "operational planning analysis;" and (3) "real-time assessment."[2]

I. Background

A. Section 215 and Mandatory Reliability Standards

3. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and

[2] NERC Glossary of Terms Used in NERC Reliability Standards (NERC Glossary).

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approval.[3] Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight or by the Commission independently.[4] In 2006, the Commission certified NERC as the ERO pursuant to section 215 of the FPA.[5]

B. Order No. 693

4. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standard PRC-001-1.[6] In addition, the Commission directed NERC to develop modifications to Reliability Standard PRC-001-1 that:

> (1) correct the references for Requirements, and [*sic*]
> (2) include a requirement that upon the detection of failures in relays or protection system elements on the Bulk-Power System that threaten reliable operation, relevant transmission operators must be informed promptly, but within a specified period of time that is developed in the Reliability Standards development process, whereas generator operators must also promptly inform their transmission operators; and (3) clarifies that, after being informed of failures in relays or protection system elements that threaten reliability of the Bulk-Power System, transmission operators must carry out corrective control actions, i.e., return a system to a stable state that

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[3] *Id.* 824o(c), (d).

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

[5] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,190, *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).

[6] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1433-1449, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

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> respects system requirements as soon as possible and no longer than 30 minutes after they receive notice of the failure.[7]

C. NERC Petition and Reliability Standards PRC-027-1 and PER-006-1

5. On September 2, 2016, NERC submitted a petition seeking Commission approval of Reliability Standards PRC-027-1 and PER-006-1.[8] NERC stated that the Reliability Standards, new and revised NERC Glossary terms, and the retirement of Reliability Standard PRC-001-1.1(ii) satisfy the Commission's criteria in Order No. 672 and are just, reasonable, not unduly discriminatory or preferential, and in the public interest.[9] NERC explained that the intent of the submitted Reliability Standards and changes to the NERC Glossary are to maintain the coordination of protection systems installed to detect and isolate faults on bulk electric system elements and require registered entities to provide training to their relevant personnel on protection systems and remedial action schemes. NERC asserted that the submitted Reliability Standards are an improvement over currently-effective Reliability Standard PRC-001-1.1(ii) and will ensure that appropriate personnel are trained on protection systems and that protection systems are appropriately studied, coordinated, and monitored.

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[7] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1449.

[8] Reliability Standards PRC-027-1 and PER-006-1 are not attached to this Final Rule. The Reliability Standards are available on the Commission's eLibrary document retrieval system in Docket No. RM16-22-000 and are posted on the NERC website, http://www.nerc.com.

[9] NERC Petition at 10.

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1. Reliability Standard PER-006-1

6. NERC stated that Reliability Standard PER-006-1 requires generator operators to use a systematic approach to develop and implement training for dispatch personnel at centrally-located dispatch centers.[10] NERC explained that Reliability Standard PER-006-1 will also cover plant personnel who are responsible for real-time control of a generator. NERC maintained that it is appropriate to train plant personnel in the functionality of protection systems and remedial action schemes. NERC observed that Reliability Standard PER-006-1 replaces the phrase "purpose and limitations" used in Reliability Standard PRC-001-1(ii) with the phrase "operational functionality" to clearly identify the objective of the training.[11] NERC also noted that Reliability Standard PER-006-1 replaces the phrase "applied in its area" in Reliability Standard PRC-001-1.1(ii) with the phrase "that affect the output of the generating facility(ies) it operates" to properly tailor the scope of the required training. NERC noted that Reliability Standard PER-006-1 does not specify a periodicity for the required training.

2. Reliability Standard PRC-027-1

7. NERC asserted that Reliability Standard PRC-027-1:

> provides a clear set of Requirements that obligate entities to (1) implement a process for establishing and coordinating new or revised Protection System settings, and (2) periodically study Protection System settings that could be affected by incremental changes in Fault current to ensure the

[10] *Id.* at 13.

[11] *Id.* at 15.

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> Protection Systems continue to operate in their intended sequence.[12]

According to NERC, Reliability Standard PRC-027-1, Requirement R1 mandates that each transmission owner, generator owner, and distribution provider establish a process for developing new and revised protection system settings for bulk electric system elements.[13]

8. NERC stated that Reliability Standard PRC-027-1, Requirement R2 mandates that every six years, applicable entities must either: (1) perform a protection system coordination study to determine whether the protection systems continue to operate in the intended sequence during faults; (2) compare present fault current values to an established fault current baseline and, only if the comparison identifies a 15 percent or greater deviation in fault current values (either three phase or phase to ground) at a bus to which the bulk electric system is connected, perform a protection system coordination study; or (3) use a combination of Options 1 and 2.[14]

9. NERC explained that Reliability Standard PRC-027-1, Requirement R3 will require applicable entities to use the process established under Reliability Standard PRC-027-1, Requirement R1 for the development of any new or revised protection system settings.

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[12] *Id.* at 26.

[13] *Id.* at 27.

[14] *Id.* at 26.

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3. Retirement of Reliability Standard PRC-001-1.1(ii)

10. NERC stated that Reliability Standard PRC-001-1.1(ii) includes six requirements that are either addressed by Reliability Standards approved by the Commission or by Reliability Standards PER-006-1and PRC-027-1. Specifically, NERC explained that Reliability Standard PRC-001-1.1(ii), Requirement R1 has been partially replaced by Reliability Standards PER-003-1 and PER-005-2. NERC continued that Reliability Standard PER-006-1 and the revised definitions of operational planning analysis and real-time assessment will replace the remaining portions of Reliability Standard PRC-001-1.1(ii), Requirement R1. NERC asserted that Reliability Standard PRC-001-1.1(ii), Requirement R2 has been addressed by Reliability Standards IRO-001-4, IRO-008-2, IRO-010-2, TOP-001-3, and TOP-003-3, which the Commission approved in Order No. 817.[15] NERC stated that Reliability Standard PRC-027-1 will replace Reliability Standard PRC-001-1.1(ii), Requirements R3 and R4. NERC also explained that Reliability Standard PRC-001-1.1(ii), Requirement R5 has been replaced with several Reliability Standards developed after Reliability Standard PRC-001-1(ii) became effective.[16] NERC further stated that Reliability Standard PRC-001-1.1(ii), Requirement R6 has been replaced with Reliability Standards TOP-001-3 and TOP-003-3.

[15] *Id*. at 5 (citing *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015)).

[16] *Id.* at 6.

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D. Notice of Proposed Rulemaking

11. On November 16, 2017, the Commission issued a Notice of Proposed Rulemaking proposing to approve Reliability Standards PRC-027-1 and PER-006-1.[17] The NOPR proposed to determine that Reliability Standards PRC-027-1 and PER-006-1 improve upon the currently-effective Reliability Standards. However, the NOPR observed that Reliability Standard PRC-027-1, Requirement R2, Option 2 does not appear to ensure coordination of all bulk electric system elements with protection system functions because it does not require an initial protection system coordination study. Accordingly, the NOPR also proposed to direct NERC, pursuant to section 215(d)(5) of the FPA, to submit modifications to Reliability Standard PRC-027-1 within 12 months of the effective date of this Final Rule to require an initial protection system coordination study to ensure that applicable entities will perform (or have performed), as a baseline, a study demonstrating proper coordination of its protection systems.[18]

12. In addition, the NOPR proposed to approve the associated violation risk factors and violation severity levels, implementation plan, and effective date proposed by

[17] *Coordination of Protection Systems for Performance During Faults and Specific Training for Personnel Reliability Standards*, Notice of Proposed Rulemaking, 82 FR 55,535 (Nov. 22, 2017), 161 FERC ¶ 61,159, at P 12 (2017) (NOPR). The NOPR was erroneously published a second time in the Federal Register on November 28, 2017, which changed the comment date to January 29, 2018. 82 FR 56,759 (Nov. 30, 2017); 82 FR 56,186 (Nov. 28, 2017).

[18] NOPR, 161 FERC ¶ 61,159 at PP 14, 24.

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NERC.[19] The NOPR also proposed to approve the revised definitions for inclusion in the NERC Glossary.[20] Further, the NOPR proposed to approve the retirement of Reliability Standard PRC-001-1.1(ii), as requested by NERC.[21]

13. In response to the NOPR, the Commission received fifteen sets of comments. We address below the issues raised in the NOPR and comments. The Appendix to this Final Rule lists the entities that filed comments in response to the NOPR.

II. Discussion

14. Pursuant to section 215(d)(2) of the FPA, we approve Reliability Standards PER-006-1 and PRC-027-1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest, as both Reliability Standards improve on currently-effective Reliability Standard PRC-001-1.1(ii) in important ways.[22] As discussed below, we do not adopt the NOPR proposal to direct NERC to modify Reliability Standard PRC-027-1 to require coordination of all bulk electric system elements with protection system functions.

15. Reliability Standard PRC-027-1 improves on currently-effective Reliability Standard PRC-001-1.1(ii) by: (1) modifying the applicability section to include the appropriate functional entity types with the responsibilities, resources, and skill sets to

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[19] *Id.* P 13.

[20] *Id.*

[21] *Id.*

[22] 16 U.S.C. 824o(d)(2).

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conduct the studies required to coordinate protection systems, and (2) listing the protection system functions on all bulk electric system elements that require coordination. Reliability Standard PER-006-1, along with existing formal training requirements in the Personnel Performance, Training, and Qualifications (PER) group of Reliability Standards, also improves upon Reliability Standard PRC-001-1.1(ii), Requirement R1 by ensuring that the necessary personnel are familiar with and understand the purpose and limitations of protection systems schemes while providing more precise and auditable requirements.

16. In addition, we approve NERC's associated violation risk factors, violation severity levels, implementation plans, and effective dates. We also approve the revised definitions for inclusion in the NERC Glossary. Further, we approve the retirement of Reliability Standard PRC-001-1.1(ii), as requested by NERC.

Initial Protection System Coordination Study

NOPR

17. The NOPR proposed to direct that NERC develop modifications to Reliability Standard PRC-027-1 to ensure coordination of all bulk electric system elements with protection system functions by requiring that applicable entities perform an initial protection coordination study under Requirement R2, Option 2.

Comments

18. NERC does not support the proposed directive because it believes that the proposed directive is unduly burdensome and unsupported by the materials cited in the NOPR. NERC contends that while the "proposed directive could potentially help reduce

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misoperations caused by coordination issues . . . [it] would also impose a significant burden on industry . . . requiring a substantial expenditure of resources."[23] NERC also states that it "expects that many entities will choose to do a full Protection System Coordination Study . . . for their more impactful [bulk electric system] Elements" and that "it is highly likely that the overwhelming majority of entities have already conducted coordination studies for their Protection Systems."[24] While NERC agrees with the goal of reducing protection system misoperation rates on the bulk electric system, it contends that recent misoperation rates demonstrate that mis-coordination of existing protection systems "does not present a widespread risk to [bulk electric system] reliability that would necessitate the expenditure of resources required to conduct full Protection System Coordination Studies for every [bulk electric system] element with a Protection System."[25]

19. In addition, NERC and other commenters contend that the materials cited in the NOPR do not support the proposal to modify Reliability Standard PRC-027-1.[26] NERC, EEI and Tri-State contend that the Arizona Southern California September 8, 2011 Outage Report is unsupportive because it addresses mis-coordination of remedial action

[23] NERC Comments at 4.

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

[25] *Id.* at 6.

[26] *See generally* NERC Comments; EEI Comments; Tri-State Comments; Entergy Comments; ITC Comments.

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schemes and not protection systems.[27] NERC and Tri-State assert that the NERC System Protection Control Task Force Report addressed issues specific to generation transmission interfaces and did not apply broadly to all bulk electric system elements with protection systems.[28] NERC and Tri-State also contend that the 2009 letter from the NERC President to the NERC board of Trustees and stakeholders is no longer relevant because mis-coordination issues are now responsible for a smaller percentage of events and that mis-coordination has not recently caused any significant system disturbances.[29] NERC and Tri-State claim that Reliability Standard PRC-004 now requires applicable entities to mitigate the effects of misoperations by implementing a corrective action plan that has reduced misoperations.[30]

20. Further, while NERC agrees with the 2013 Misoperations Report that reducing misoperations, including mis-coordination events, is an important priority for bulk electric system reliability, NERC contends that the report does not indicate that requiring protection system coordination studies for all applicable elements, as proposed in the NOPR, is the only or optimal way to reduce mis-coordination events.[31] EEI also contends that the 2013 Misoperations Report shows that human error and lack of training

[27] NERC Comments at 7; EEI Comments at 7; Tri-State Comments at 7-8.

[28] NERC Comments at 7-8; Tri-State Comments at 8-9.

[29] NERC Comments at 8; Tri-State Comments at 9-10.

[30] NERC Comments at 8; Tri-State Comments at 9.

[31] NERC Comments at 9.

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are responsible for a significant portion of misoperations.[32]

21. NERC, EEI, and Tri-State explain that the 2014 incident identified in the "lessons learned" document on "Generation Relaying – Underfrequency Protection Coordination" was unrelated to protection system coordination.[33]

22. Finally, NERC states that while the 2016 State of Reliability Report highlights the continued need to reduce misoperations, the report does not indicate that there is a need to require entities to perform a protection system coordination study for every bulk electric system element with a protection system.[34] NERC also contends that the 2017 State of Reliability Report observes a continuing decline in misoperation rates, but that misoperations are a priority for NERC.[35] NERC states that the misoperations rate within the Texas Reliability Entity Region observed in the 2016 State of Reliability Report was mitigated by the time NERC issued the 2017 State of Reliability Report.[36] NERC claims that this reduction in misoperation events is evidence that requiring entities to perform protection system coordination studies is unnecessary because the entities will address the misoperation events without specific requirements in Reliability Standards.[37]

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[32] EEI Comments at 7.

[33] NERC Comments at 10; EEI Comments at 8; Tri-State Comments at 10.

[34] NERC Comments at 10.

[35] *Id.* at 9.

[36] NERC Comments at 11; *see also* Entergy Comments at 8.

[37] NERC Comments at 11.

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23. Other commenters do not support the proposal to direct NERC to develop modifications to Reliability Standard PRC-027-1 because they generally contend that the proposed directive is not necessary and would impose a burden without a proportional reliability benefit.[38] Hydro One estimates that it will need approximately 30,000 hours of work to perform an initial protection system coordination study.[39] Tri-State estimates that it would take an engineer at least twenty hours to perform a protection system coordination study at each of its approximately 700 terminals.[40] Tri-State estimates that the actual cost to all applicable entities could be more than $120 million.[41] PG&E estimates a cost to industry "greatly in excess of $100 million" and asserts that the proposed directive would require PG&E to perform coordination studies for 95 percent of the PG&E bulk electric system at a cost of $3.5 million in engineering labor.[42]

24. Entergy requests that the Commission find that NERC's approach for requiring protection system coordination studies achieves the Reliability Standard's "reliability

[38] APPA/TAPS Comments at 3; EEI Comments at 3; El Paso Electric Comments at 4; Entergy Comments at 4; Hydro One Comments at 1-2; ITC Comments at 3; LPPC Comments at 2; NPPD Comments at 1; NRECA/ELCON Comments at 5; Oncor Comments at 1; PG&E Comments at 2; SCE&G Comments at 1; Tri-State Comments at 4.

[39] Hydro One Comments at 1.

[40] *Id.* at 13.

[41] *Id.*

[42] PG&E Comments at 3.

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goals effectively and efficiently."[43] Entergy opines that, by adopting NERC's proposal without modification, the Commission appropriately would give "due weight" to the technical expertise of the ERO. Entergy asserts that NERC properly supported Requirement R2 by setting forth evidence of the frequency of coordination events over a four-year period, which shows that only 11 percent of misoperation events (17 events out of 151) and only 2.9 percent of total events (17 out of 574) involved Protection System coordination issues. Further, Entergy claims that, in proposing the Reliability Standard, NERC was aware of the possibility that some bulk electric system elements may never undergo a Protection System Coordination Study and that "NERC does not afford this possibility the same risk as the Commission."[44] According to Entergy, "NERC has properly balanced the implementation costs and reliability benefits of the proposed PRC-027-1 Reliability Standard and determined that Option 2 is sufficient to ensure reliability" and the Commission should defer to NERC's expertise, or otherwise provide more support to justify a deviation from NERC's proposal.

25. In addition, some commenters expressed concern that applicable entities may not have maintained sufficient documentation to substantiate prior protection system coordination studies and, as result, entities would have to perform new protection system coordination studies purely for compliance purposes.[45]

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[43] Entergy Comments at 5.

[44] *Id*. at 9-10.

[45] ITC Comments at 4; Entergy Comments at 1; NPPD Comments at 1; PG&E *(continued ...)*

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26. As an alternative to the proposed directive, NERC and other commenters suggest that Reliability Standard PRC-027-1 be modified so that it requires an applicable entity to conduct an initial baseline protection system coordination study on a certain subset of its bulk electric system elements (i.e., based on a higher voltage or higher risk protection systems).[46] NERC and other commenters also request that the Commission permit NERC to allow more than 6 years to complete the initial baseline protection system coordination studies (i.e., 10 or 12 years) if the Commission directs NERC to modify Reliability Standard PRC-027-1.[47] EEI recommends that if the Commission continues to have concerns about Reliability Standard PRC-027-1, Requirement R2, Option 2, as an alternative to the proposed directive, a final rule should direct NERC "to assess the

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Comments at 3.

[46] NERC Comments at 11-12; El Paso Electric Comments at 2; Entergy Comments at 12; NRECA/ELCON Comments at 6-7.

[47] NERC Comments at 12; El Paso Electric Comments at 2-3; Entergy Comments at 12-13; NRECA/ELCON Comments at 6-7. Separately, El Paso Electric contends that the six-year cycle proposed by NERC in Reliability Standard PRC-027-1, Requirement R2 is too short and directs resources away from "other activities that have a greater likelihood of improving reliability outcomes in a demonstrable way." El Paso Electric Comments at 2. We disagree. NERC recognized the potential burden imposed by Requirement R2 and determined that six years "balance[d] the resources required to perform Protection System Coordination Studies and the potential reliability impacts created by incremental changes of Fault current over time." NERC Petition at 40. Moreover, during the standard drafting process, some commenters indicated that six years was too long an interval. *See, e.g.*, NERC Petition, Exhibit G (Summary of Development History and Record of Development) at 1479 of pdf (ReliabilityFirst recommending a 24-month period to conduct protection system coordination study), 2169 of pdf (Texas RE stating that six years is too long of a time period between studies of fault currents).

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effectiveness of Option 2 after the implementation of the proposed Reliability Standard and if necessary make technical recommendations to improve the efficiency and effectiveness as appropriate."[48]

27. Idaho Power supports the proposed directive.[49] Idaho Power supports eliminating Reliability Standard PRC-027-1, Requirement R2, Option 2 because it contends that Option 1 is a more robust option explaining that it is "preferable because it is more likely to address miscoordinations."[50]

Commission Determination

28. Based on the record before us, we do not adopt the directive proposed in the NOPR. The record in this proceeding supports the NOPR's conclusion that mis-coordination of protection systems may pose a potential reliability risk and, as currently drafted, Reliability Standard PRC-027-1, Requirement R2, Option 2 permits applicable entities to forego protection system coordination studies under certain circumstances.[51] However, we are persuaded by the statements from NERC and other

[48] EEI Comments at 6.

[49] Idaho Power Comments at 1-2.

[50] *Id.* at 2.

[51] *See*, *e.g.*, NERC Comments at 6 ("NERC and the standard drafting team concluded that Protection System coordination did not present a prevalent enough risk to the reliable operation of the [bulk electric system] to warrant imposing the burden of requiring applicable entities to perform a full Protection System Coordination Study for every [bulk electric system] Element with a Protection System."); Entergy Comments at 9 ("In proposing the Reliability Standard, NERC was aware of the possibility that some bulk electric system elements may never undergo a Protection System Coordination *(continued ...)*

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commenters that applicable entities generally perform, or will choose to perform for their significant facilities, protection system coordination studies even in the absence of a Reliability Standard requirement.[52] We also recognize the concern raised by commenters regarding the burden of compliance. Specifically, we recognize the concern that were the NOPR directive adopted, applicable entities could be required to re-run protection system coordination studies for the sole purpose of generating compliance documentation, even if such entities already performed protection system coordination studies that remain valid but lack documentation to substantiate compliance. Accordingly, pursuant to 215(d)(2) of the FPA, we approve Reliability Standard PRC-027-1 and do not direct modifications to the Reliability Standard.[53]

III. Information Collection Statement

29. The collections of information addressed in this Final Rule are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[54] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[55] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration

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Study.").

[52] *See, e.g.*, NERC Comments at 5; NPPD Comments at 1; Tri-State Comments at 10; ITC Comments at 4.

[53] 16 U.S.C. 824o(d)(2).

[54] 44 U.S.C. 3507(d) (2012).

[55] 5 CFR 1320.11 (2017).

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date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

30. The Commission solicited public comments in the NOPR on the need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. The Commission did not receive comments regarding the burden estimates for the Reliability Standards approved herein (i.e., Reliability Standards PRC-027-1 and PER-006-1).[56]

31. The information collection requirements in this Final Rule in Docket No. RM16-22-000 are associated with FERC-725A, FERC-725G, and FERC-725Y, as discussed below.[57]

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[56] As discussed above, several commenters addressed the potential burden of a new version of Reliability Standard PRC-027-1 modified, pursuant to the Commission's directive, to require initial protection system coordination studies. *See, e.g.*, Tri-State Comments at 12. However, those comments are not relevant to the burden estimates contained in this Final Rule because, herein, the Commission only approves Reliability Standards PRC-027-1 and PER-006-1.

[57] In the NOPR in Docket No. RM16-22-000, some of the reporting requirements were included under FERC-725G6 (OMB Control No. 1902-0300), a temporary place holder, because FERC-725G was pending review at OMB in an unrelated action. As indicated below, those reporting requirements are now included under FERC-725G (OMB Control No. 1902-0252). When the NOPR in Docket No. RM16-22-000 was issued, another unrelated item affecting FERC-725A was pending OMB review. Burden estimates were provided in order to solicit public comments, but the burden reduction to FERC-725A was not submitted to OMB at that time. The burden reduction to *(continued ...)*

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32. Public Reporting Burden: The number of respondents below is based on an examination of the NERC compliance registry on December 1, 2017, for transmission owners, generator owners, generator operators, and distribution providers within the United States and an estimate of how many such entities from that registry will be affected by the Reliability Standards in this Final Rule for adoption and implementation. As of December 1, 2017, 337 transmission owners, 971 generator owners, 944 generator operators, and 419 distribution providers in the United States were registered in the NERC compliance registry. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting. We note that many generation sites share a common generator owner or generator operator. The following table provides the estimated annual burden and cost related to information collection requirements in this Final Rule.[58]

FERC-725A for this Final Rule will be submitted to OMB for review.

[58] TO=transmission owner; TOP=transmission operator; GO=generator owner; GOP=generator operator; DP=distribution provider; and BA=balancing authority.

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Changes due to the Final Rule in Docket No. RM16-22-000					
Respondent Category and Requirement[59]	**Number of Respondents (1)**	**Annual Number of Responses per Respondent (2)**	**Total Number of Annual Responses (1)*(2)=(3)**	**Average Burden Hours & Cost per Response[60] (4)**	**Annual Burden Hours & Total Annual Cost (rounded)[61] (3)*(4)=(5)**
FERC-725G (Reliability Standard PRC-027-1)[62]					
TO; Reporting Reqs. R1, R2, & R3	337	1	337	60 hrs.; $3,941.40	20,220 hrs.; $1,328,252
TO; Recordkeeping Reqs.	337	1	337	40 hrs.; $1,565.60	13,480 hrs.; $527,607

[59] For each Reliability Standard, the Measure shows the acceptable evidence for the associated Reporting Requirement, and the Compliance section details the related Recordkeeping Requirement.

[60] The estimates for cost per hour are based on May 2016 wage figures from the Bureau of Labor Statistics (BLS, https://www.bls.gov/oes/current/naics2_22.htm) and BLS benefits information from March 20, 2018 (for December 2017, https://www.bls.gov/news.release/ecec.nr0.htm). The estimated hourly cost, for wages plus benefits, are: (a) $68.12/hour, for electrical engineer, Occupation Code 17-2071, and (b) $39.14/hour, for information and record clerk, Occupation Code 43-4199.

The hourly cost for an electrical engineer is used for the reporting requirements; the hourly cost for a record clerk is used for the recordkeeping requirements.

[61] For display purposes, the cost figures in column 5 have been rounded.

[62] Some of the reporting requirements are required at least every six calendar years. In this table, the Commission assumes that respondents might work on some of their elements each year; the annual burden estimate shown is one sixth of the burden associated with one complete six-year cycle. For example, for each transmission owner: (a) the annual reporting burden associated with Requirements R1, R2, and R3 is shown as 60 hours per year, and (b) the burden for the six-year cycle would be six times that, or a total of 360 hours.

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GO; Reporting Reqs. R1, R2, & R3	971	1	971	10 hrs.; $656.90	9,710 hrs.; $637,830
GO; Recordkeeping Reqs.	971	1	971	10 hrs.; $391.40	9,710 hrs.; $380,049
DP; Reporting Reqs R1, R2, & R3	419	1	419	10 hrs.; $656.90	4,190 hrs.; $275,241
DP; Recordkeeping Reqs.	419	1	419	10 hrs.; $391.40	4,190 hrs.; $163,997
Sub-Total for Reporting Reqs. for FERC-725G					34,120 hrs.; $2,241,323
Sub-Total for Recordkeeping Reqs. for FERC-725G					27,380 hrs.; $1,072,653
Total Increase for FERC-725G					61,500 hrs.; $3,313,976
FERC-725Y (Reliability Standard PER-006-1)[63]					
GOP; Reporting Req. R1	944	1	944	5 hrs.; $328.45	4,720 hrs.; $310,057

[63] In order to provide improved information on the Reliability Standard and associated burden, FERC-725Y (rather than FERC-725A) will cover the burden required by PER-006-1.

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GOP; Recordkeeping Req.	944	1	944	10 hrs.; $391.40	9,440 hrs.; $369,482
Total Increase for FERC-725Y					14,160 hrs.; $679,539
Reductions to FERC-725A (retirement of Reliability Standard PRC-001-1.1)[64]					
GOP; Reporting Req.	944	1	944	40 hrs.; $2,627.60	37,760 hrs.; $2,480,454
GOP; Recordkeeping Req.	944	1	944	50 hrs.; $1,957.00	47,200 hrs.; $1,847,408
TOP; Reporting Req.	176	1	176	60 hrs.; $3,941.40	10,560 hrs.; $693,686
TOP; Recordkeeping Req.	176	1	176	70 hrs.; $2,739.80	12,320 hrs.; $482,205
BA; Reporting Req.	99	1	99	32 hrs.; $2,102.08	3,168 hrs.; $208,106
BA; Recordkeeping Req.	99	1	99	20 hrs.; $782.80	1,980 hrs.; $77,497
Reduction Sub-Total Reporting Reqs. for FERC-725A					51,484 hrs.; $3,382,246

[64] The estimates for average annual burden hours per response are based on figures in Order No. 693. Order No. 693, FERC Stats. & Regs. ¶ 31,242, at PP 1906-1907. The numbers of respondents and estimated hourly costs are based on current figures.

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Reduction Sub-Total Recordkeeping Reqs. for FERC-725A					61,500 hrs.; $2,407,110
Reduction Sub-Total for FERC-725A					112,984 hrs.; $5,789,356 (reduction)
NET TOTAL REDUCTION FOR CHANGES IN RM16-22-000					**37,324 hrs.; $1,795,841 (reduction)**

Titles: FERC-725A (Mandatory Reliability Standards for the Bulk-Power System), FERC-725G (Reliability Standards for the Bulk Power System: PRC Reliability Standards) and FERC-725Y (Mandatory Reliability Standards: Operations Personnel Training).

Action: Revisions to existing collections.

OMB Control Nos.: 1902-0244 (FERC-725A); 1902-0252 (FERC-725G) and 1902-0279 (FERC-725Y).

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

Frequency of Responses: Annual recordkeeping and reporting requirements, with some reporting requirements being at least once every six years.

Necessity of the Information: Reliability Standards PRC-027-1 and PER-006-1 set forth requirements for coordination of protection systems and personnel training on specific

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topics essential to reliability. The Commission approves Reliability Standards PRC-027-1 and PER-006-1, which will replace Commission-approved Reliability Standard PRC-001-1.1(ii). Reliability Standards PRC-027-1 and PER-006-1 improve upon existing Reliability Standard PRC-001-1.1(ii) because the Reliability Standards assign responsibilities to entities with more appropriate resources and skill sets to conduct studies required to coordinate protection systems. The approved Reliability Standards also provide additional clarity to applicable entities.

Internal review: The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

IV. Environmental Analysis

33. 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.[65] The action proposed here falls within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.[66]

V. Regulatory Flexibility Act

34. The Regulatory Flexibility Act of 1980 (RFA) generally requires a description and

[65] *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).

[66] 18 CFR 380.4(a)(2)(ii) (2017).

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analysis of final rules that will have significant economic impact on a substantial number of small entities.[67] The Small Business Administration (SBA) defines which utilities are small businesses based on the number of employees that a utility and its affiliates employ.[68]

35. Reliability Standard PRC-027-1 (included in FERC-725G) will apply to approximately 1,727 entities (337 transmission owners, 971 generator owners, and 419 distribution providers) in the United States.[69] Pursuant to SBA regulations, the small business threshold for Electric Bulk Power Transmission and Control is 500 employees. For generator owners, the small generator threshold ranges from 250 to 750 employees (depending on the fuel source). For Electric Power Distribution, the small business threshold is 1,000 employees. We estimate that the annual cost for each entity will be $1,048 for each generator owner and distribution provider and $5,507 for each transmission owner.

36. Reliability Standard PER-006-1 (included in FERC-725Y) will apply to approximately 944 generator operators in the United States. Pursuant to SBA regulations the small business threshold for generator operators ranges from 250 to 750 employees (depending on the fuel source). We estimate that the annual cost for each generator

[67] 5 U.S.C. 601-612 (2012).

[68] 13 CFR 121.201, Subsector 221 (2017).

[69] Many respondents serve multiple roles in the NERC compliance registry, so there is likely double counting in the estimates.

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operator will be $719.

37. The retirement of Reliability Standard PRC-001-1.1(ii) (included in FERC-725A) will decrease the annual estimated cost for 944 generator operators by $4,585 each, for 176 transmission operators by $6,681 each, and for 99 balancing authorities by $2,885 each. For the generator operators affected by this retirement and approval of Reliability Standard PER-006-1, the net annual effect would be a decrease of $3,866 each.

38. We estimate the net annual cost of this Final Rule would vary, by type of entity, from an annual decrease of $6,681 (for each transmission operator) to an annual increase of $5,507 (for each transmission owner). We view this as a minimal economic impact for each entity. Accordingly, we certify that this Final Rule will not have a significant economic impact on a substantial number of small entities.

VI. Document Availability

39. 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 FERC's Home Page (http://www.ferc.gov) and in FERC'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.

40. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the

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docket number field.

41. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at 202-502-8371, TTY 202-502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

VII. Effective Date and Congressional Notification

42. The Final Rule is effective [**INSERT DATE 60 days from publication in FEDERAL REGISTER**]. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. This Final Rule is being submitted to the Senate, House, and Government Accountability Office.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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Appendix

List of Commenters

APPA/TAPS	American Public Power Association and Transmission Access Policy Study Group
EEI	Edison Electric Institute
El Paso Electric	El Paso Electric Company
Entergy	Entergy Services, Inc.
Hydro One	Hydro One Networks Inc.
Idaho Power	Idaho Power Company
ITC	International Transmission Company d/b/a ITC Transmission, Michigan Electric Transmission Company, LLC, ITC Midwest LLC and ITC Great Plains, LLC
LPPC	Large Public Power Council
NPPD	Nebraska Public Power District
NERC	North American Electric Reliability Corporation
NRECA/ELCON	National Rural Electric Cooperative Association and the Electricity Consumers Resource Council
Oncor	Oncor Electric Delivery
PG&E	Pacific Gas and Electric Company
SCE&G	South Carolina Electric and Gas Company
Tri-State	Tri-State Generation and Transmission Association, Inc.

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Document Content(s)

RM16-22-000.DOCX.....1-31

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

May 10, 2018

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. No. 94-409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING:	FEDERAL ENERGY REGULATORY COMMISSION
DATE AND TIME:	May 17, 2018 10:00 A.M.
PLACE:	Room 2C 888 First Street, N.E. Washington, D.C. 20426
STATUS:	OPEN
MATTERS TO BE CONSIDERED:	Agenda * NOTE - Items listed on the agenda may be deleted without further notice.
CONTACT PERSON FOR MORE INFORMATION:	Kimberly D. Bose Secretary Telephone (202) 502-8400 For a recorded message listing items struck from or added to the meeting, call (202) 502-8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's website at http://ferc.capitolconnection.org/ sing the eLibrary link, or may be examined in the Commission's Public Reference Room.

1043rd - MEETING

REGULAR MEETING

May 17, 2018

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD18-1-000	Agency Administrative Matters
A-2	AD18-2-000	Customer Matters, Reliability, Security and Market Operations
A-3	AD06-3-000	2018 Summer Market and Reliability Assessment
		ELECTRIC
E-1	RM18-8-000	Geomagnetic Disturbance Reliability Standard
E-2	RM16-15-001	Regulations Implementing FAST Act Section 61003-Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information
E-3	ER16-204-001	Southwest Power Pool, Inc.
E-4	ER17-1575-002	Southwest Power Pool, Inc.
E-5	EL16-110-002 EL17-69-001 (Not Consolidated)	Southwest Power Pool, Inc. Buffalo Dunes Wind Project, LLC, Enel Green Power North America, Inc., Alabama Power Company, and Southern Company Services, Inc. v. Southwest Power Pool, Inc.
E-6	EL17-59-001	Joint California Complainants v. Pacific Gas and Electric Company
E-7	EL17-95-000 ER17-2154-000 (Consolidated)	California Public Utilities Commission, Transmission Agency of Northern California, Sacramento Municipal Utility District, M-S-R Public Power Agency, City of Santa Clara, California, State Water Contractors, Modesto Irrigation District, and Northern California Power Agency v. Pacific Gas and Electric Company Pacific Gas and Electric Company

E-8	EL18-58-000	Oklahoma Municipal Power Authority v. Oklahoma Gas and Electric Company
E-9	EL17-70-000 QF17-935-001 QF17-936-001	Zeeland Farm Services, Inc.
E-10	EL15-3-002	City and County of San Francisco v. Pacific Gas and Electric Company
	ER15-702-002 ER15-703-002 ER15-704-005 ER15-705-002 ER15-735-002	Pacific Gas and Electric Company
	(Consolidated)	
E-11	EL01-88-015	Louisiana Public Service Commission v. Entergy Services, Inc.
E-12	EL01-88-017	Louisiana Public Service Commission v. Entergy Services, Inc.

Miscellaneous

M-1	OMITTED	
M-2	RM18-7-000	Withdrawal of Pleadings

GAS

G-1	RP16-1299-003 RP17-977-000 (Consolidated)	Kinetica Energy Express, LLC
G-2	OR18-9-000	White Cliffs Pipeline, L.L.C.
G-3	OMITTED	
G-4	OR15-6-000	Seaway Crude Pipeline Company LLC
G-5	RP17-811-001	Peregrine Oil & Gas II, LLC v. Texas Eastern Transmission, LP

HYDRO

H-1	RM18-14-000	Elimination of Form 80 and Revision of Regulations on Recreational Opportunities and Development at Licensed Hydropower Projects

CERTIFICATES

C-1	CP17-476-000	Gulf South Pipeline Company, LP
C-2	CP18-48-000	Tennessee Gas Pipeline Company, L.L.C. Kinder Morgan Border Pipeline LLC Kinder Morgan Tejas Pipeline LLC

Kimberly D. Bose,
Secretary.

A free webcast of this event is available through http://ferc.capitolconnection.org/. Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit http://ferc.capitolconnection.org/ or contact Danelle Springer or David Reininger at 703-993-3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

May 2018
Commission Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its May 17, 2018 public meeting. The summaries are produced by FERC's Office of External Affairs and are intended to provide only a general synopsis of the orders. These summaries are not intended as a substitute for the Commission's official orders. To determine the specific actions and the Commission's reasoning, please consult the individual orders when they are posted to FERC's eLibrary found at www.ferc.gov.

FERC proposes a rule

E-1, *Geomagnetic Disturbance Reliability Standard*, Docket No. RM18-8-000. This Notice of Proposed Rulemaking addresses proposed Reliability Standard TPL-007-2 (Transmission System Planned Performance for Geomagnetic Disturbance Events) submitted by the North American Electric Reliability Corporation (NERC). The proposed Reliability Standard was developed and submitted by NERC in response to a Commission directive in Order No. 830 to modify currently effective Reliability Standard TPL-007-1.

FERC clarifies an order, denies, in part, and grants, in part, rehearing

E-2, *Regulations Implementing FAST Act Section 61003 - Critical Electric Infrastructure Security and Amending Critical Infrastructure Information*, Docket No. RM16-15-001. This order denies, in part, and grants, in part, Edison Electric Institute's request for clarification or, in the alternative, rehearing of Order No. 833 that amends the Commission's regulations to implement provisions of the Fixing America's Surface Transportation Act pertaining to the designation, protection, and sharing of Critical Energy/Electric Infrastructure Information.

FERC affirms an Initial Decision

E-3, *Southwest Power Pool, Inc*., Docket No. ER16-204-001. The order affirms the Presiding Judge's finding that SPP's proposed revisions to its tariff to incorporate Tri-State Generation and Transmission Cooperative, Inc. as a new transmission owner are just and reasonable.

FERC denies rehearing

E-4, *Southwest Power Pool, Inc.*, Docket No. ER17-1575-002. This order denies rehearing of an October 19, 2017 order that rejected proposed revisions to SPP's tariff regarding the eligibility of customers with network service subject to redispatch to receive Auction Revenue Rights and Long-Term Congestion Rights.

FERC denies rehearing

E-5, *Southwest Power Pool, Inc., Buffalo Dunes Wind Project, LLC, Enel Green Power North America, Inc., Alabama Power Co., and Southern Co. Services, Inc. v. Southwest Power Pool, Inc.*, Docket Nos. EL16-110-002 and EL17-69-001. This order denies rehearing of the October 19, 2017 orders in Docket Nos. EL16-110-000 (Paper Hearing Order) and EL17-69-000 (Complaint Order). The Paper Hearing Order found SPP's tariff provisions regarding the allocation of Auction Revenue Rights (ARRs) and Long-Term Congestion Rights (LTCRs) to customers with network service subject to redispatch to be unjust and unreasonable, and the Complaint Order denied a complaint alleging that SPP's prior allocation of ARRs and LTCRs to customers with network service subject to redispatch violated its tariff.

FERC denies rehearing

E-6, *Joint California Complainants v. Pacific Gas and Electric Co.*, Docket No. EL17-59-001. This order denies a request for rehearing of the Commission's November 16, 2017 Order that denied a complaint against Pacific Gas and Electric Co. (PG&E) regarding PG&E's eighteenth transmission owner tariff rates.

FERC establishes hearing and settlement judge procedures

E-7, *California Public Utilities Commission v. Pacific Gas & Electric Co*., Docket Nos. EL17-95-000 and ER17-2154-000. This order establishes hearing and settlement judge procedures to investigate Pacific Gas & Electric Co.'s most recent rate increase, TO19, in response to a complaint filed by several California agencies and organizations. The order also consolidates this matter with the hearing and settlement judge procedures that are ongoing in Docket No. ER17-2154-000.

FERC establishes hearing and settlement judge procedures

E-8, *Oklahoma Municipal Power Authority v. Oklahoma Gas and Electric Co.*, Docket No. EL18-58-000. This order sets Oklahoma Municipal Power Authority's complaint against Oklahoma Gas and Electric Co. (OG&E) for hearing and settlement judge procedures. The complaint alleges that OG&E's base return on equity is unjust and

unreasonable and that OG&E's formula rate needs to be revised to reflect all of the effects of the Tax Cuts and Jobs Act.

FERC denies, in part, a waiver request

E-9, *Zeeland Farm Services, Inc*., Docket No. EL17-70-000, *et al*. The order denies, in part, and grants, in part, a requested waiver of the qualifying facility filing requirements of 18 C.F.R. § 292.203(a)(3), so that Zeeland Farm's facilities will be treated as qualifying facilities for the period that they operated out of compliance with section 292.203(a)(3). As a consequence, the facilities will qualify for most of the exemptions contained in sections 292.601 and 292.602 of the Commission's regulations, excepting the exemption from sections 205 and 206 of the Federal Power Act.

FERC affirms an Initial Decision

E-11, *Louisiana Public Service Commission v. Entergy Services, Inc*., Docket No. EL01-88-015. The order affirms the Presiding Judge's findings that the appropriate start date for interest is June 1, 2006, the date that payments should have been made, rather than June 1, 2005, the first day of the test period. The order affirms the Presiding Judge's finding that a portion of Entergy Louisiana's Net Operating Loss Accumulated Deferred Income Tax (ADIT) is attributable to the Vidalia tax deduction. The order also affirms the Presiding Judge's related finding that it is appropriate to exclude from the 2005 bandwidth calculation Net Operating Loss ADIT recorded in Account 190 that is attributable to the Vidalia tax deduction. The order agrees with the Presiding Judge that Entergy did not properly account for certain regulatory asset deferrals. Although the Presiding Judge did not address whether corrections for the regulatory asset deferrals should be made for years subsequent to the 2005 bandwidth period, the order finds that making such corrections is necessary to ensure proper implementation of the filed rate.

FERC partially affirms an Initial Decision

E-12, *Louisiana Public Service Commission v. Entergy Services, Inc*., Docket No. EL01-88-017. The order affirms the Presiding Judge's ruling that the 2006 Compliance Tariff should be used for calculating bandwidth payments and receipts for the 2005 bandwidth period. The order disagrees with the Presiding Judge's decision that the bandwidth formula to be used in this proceeding must contain all amendments that have been made to the formula in subsequent years. The order finds that the Presiding Judge was correct to summarily strike certain other issues that constitute collateral attacks on prior Commission orders.

FERC approves a final rule

M-2, *Withdrawal of Pleadings*, Docket No. RM18-7-000. This final rule adopts the more accurate title of "Withdrawal of Pleadings" for Rule 216 from the Commission's Rules of Practice and Procedure. The final rule also clarifies the text of Rule 216.

FERC accepts a filing

G-1, *Kinetica Energy Express, LLC*, Docket Nos. RP16-1299-003, RP17-977-000. The order accepts a multi-part compliance filing regarding secondary point rights and curtailment policy.

FERC establishes hearing procedures

G-2, *White Cliffs Pipeline, L.L.C.*, Docket No. OR18-9-000. This order addresses White Cliffs' application for market-based rates for crude oil transportation on its pipeline from Platteville, Colorado, (in the proposed origin market of the Niobrara Shale Region) to Cushing, Oklahoma, (in the proposed destination market of BEA No. 170, Tulsa-Bartlesville, Oklahoma). The order grants the pipeline's request for market-based rate authority for its destination market and sets for hearing the issue of whether the pipeline has market power in the proposed origin market.

FERC affirms an Initial Decision

G-4, *Seaway Crude Pipeline Company LLC*, Docket No. OR15-6-000. This order involves Seaway's application for market-based rate authority for its crude oil pipeline transporting crude oil from its origin at Cushing, Oklahoma, to the U.S. Gulf Coast. The order affirms the Presiding Judge's finding that Seaway lacks significant market power in its origin and destination markets, and grants Seaway market-based rate authority. The order also clarifies that, when conducting a market power analysis, the focus on used alternatives includes only those alternatives that are currently used, and that determining whether a competitive alternative is currently used is a fact-based analysis to be conducted on a case-by-case basis.

FERC denies rehearing

G-5, *Peregrine Oil & Gas II, LLC*, Docket No. RP17-811-001. This order dismisses a request by Peregrine for rehearing and clarification of an October 27, 2017 order in this proceeding. Peregrine's complaint alleged that Texas Eastern Transmission LP (Texas Eastern) violated its service obligations under its tariff and section 4 of the Natural Gas Act (NGA) by failing to exercise due diligence to remedy an outage on its FERC-certificated Line 41-A system. In the October 2017 order, the Commission addressed certain matters raised by the complaint and set the remaining issues for hearing. In

particular, the Commission found that a temporary outage of Texas Eastern's Line 41-A did not amount to an abandonment of service on the line within the meaning of the NGA. The rehearing order denies Peregrine's request for reasons similar to those contained in the October 27, 2017 Order.

FERC proposes a rule

H-1, *Elimination of Form 80 and Revision of Regulations on Recreational Opportunities and Development at Licensed Hydropower Projects*, Docket No. RM18-14-000. The Notice of Proposed Rulemaking proposes to revise the Commission's regulations to eliminate the Licensed Hydropower Development Recreation Report, designated as FERC Form No. 80 (Form 80). Form 80 solicits information on the use and development of recreation facilities at hydropower projects licensed by the Commission under the Federal Power Act. The proposed elimination of Form 80 would reduce burden on licensees and Commission staff alike. In addition, the Commission proposes to revise sections 8.1 and 8.2 of its regulations, related to recreational use and development at licensed projects, in order to modernize public notice practices, clarify recreational signage requirements, and provide flexibility to assist licensees' compliance efforts.

FERC grants conditional authorization for a proposed pipeline expansion

C-1, *Gulf South Pipeline Company, LP,* Docket No. CP17-476-000. The order grants Gulf South a certificate of public convenience and necessity to construct and operate the proposed Westlake Expansion Project in Calcasieu Parish, Louisiana, that will provide firm transportation service to Entergy Louisiana, LLC's proposed Lake Charles Power Plant.

FERC grants conditional authorization for a leased capacity agreement

C-2, *Tennessee Gas Pipeline Company, L.L.C., Kinder Morgan Border Pipeline LLC and Kinder Morgan Tejas Pipeline LLC*, Docket No. CP18-48-000. The order grants subject to conditions, the requests of Tennessee, Border, and Tejas that seek authorization for Tennessee to lease capacity on Border's and Tejas' pipelines. Specifically, Tennessee seeks authorization to acquire 100,000 dekatherms per day of capacity in northern Texas by lease from Border and Tejas. Border and Tejas are intrastate pipeline companies that request limited jurisdiction certificates enabling Tennessee to use existing capacity on their systems, under a capacity lease, to provide firm transportation service in interstate commerce and for a determination that leasing capacity to Tennessee will not affect their status as intrastate pipeline companies otherwise exempt from the Commission's jurisdiction.

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Lesson Learned

Loss of Communication to Multiple SCADA RTUs at a Switching Center

Primary Interest Groups
Transmission Operators (TOPs)
Reliability Coordinators (RCs)

Problem Statement
Grid operations lost communication with multiple substation remote terminal units (RTUs) when conditions allowed a pre-existing configuration error to express itself. The event that transpired had wide reaching impacts to both control center operations and field personnel.

Details
Communication with a total of 87 RTUs was lost, including 34 Bulk Electric System (BES) RTUs. The various substations affected had operating voltages ranging from four kV to 500 kV. This resulted in the loss of substation control and data acquisition (SCADA) functionality. The total event duration was 78 minutes.

Context Behind the Event:
A Regional switching center that contained the energy management system (EMS) platform for the area's RTU communication was relocated to a newly constructed control room approximately two months prior to this event. The power for this EMS platform was routed through an uninterruptible power supply (UPS) that was a new and different model compared to other Regional switching center facilities.

A transformer that supplied the primary station service power source was taken out of service for maintenance. This created a UPS general alarm that was acknowledged by both the switching center system operator and the transmission dispatcher. The switching center system operator determined that a substation operator needed to be called out to investigate the cause of the alarm. Due to distractions with other scheduled switching that was also taking place, the dispatch request was never issued and the cause of the UPS general alarm was not investigated.

Approximately 5.5 hours later, and as a result of the UPS general alarm not being investigated, communication with the 87 RTUs was lost as the UPS system was operating in battery mode and was unable to maintain proper voltage to operate the communications equipment. A technician was sent to determine the cause of the power failure and found the main circuit breaker to the UPS tripped.

This main circuit breaker was reset and closed by the technician, restoring power to the RTU communications equipment.

Upon Further Review
An inspection determined that the UPS auto/manual restart switch was selected to the manual position, a factory default setting the vendor was unaware of and did not correct during in-servicing of the new

system. In the manual configuration, the UPS system is designed to trip the main circuit breaker for a momentary loss of ac power, and go on battery power as experienced during the event.

The vendor has since set the switch to the "auto" position, which will ensure that the main circuit breaker remains closed and the UPS transfers to the alternate ac power supply. Subsequent local testing has verified the UPS system automatic transfer switch to be functional and now appropriately set.

A latent error had created a system condition that lay undetected until specific circumstances were achieved.

Latent Error:
An error is considered a "Latent Error" when the error has no immediate impact and is not detected until certain conditions trigger or allow its consequences to be revealed. In this case, it was a switch left in the wrong position for the equipment's application.
Some other examples:

- Miswiring that defeats a protection system while not causing an alarm and is not caught in post-modification testing.
- A typo in a database that changes a maintenance schedule from six months to six years, resulting in equipment failure due to lack of maintenance.

Human Performance Perspective

Testing and Energization of New Equipment

The time when new equipment is being installed is the best opportunity for local technicians and substation operators to work with vendors and receive training on new equipment.

The "As Left" condition of newly installed equipment needs to be understood and verified so that proper operation will occur when called upon to perform its required function.

Equipment Has Become More Advanced And Complicated

Many times, physical control switches have been replaced with logic buried in menus on a display screen. This can result in unwanted factory default settings remaining "as delivered" and resulting in equipment not operating as expected.

Control/selector switches may be located in areas that are not normally inspected on a routine basis. This can lead to a condition that is not readily visible to the technician or substation operator.

Understanding the Meaning and Significance of Alarms

There are several circumstances where alarms are grouped together to produce one alarm point and then require in-depth local troubleshooting to determine the actual problem.

Alarm nomenclature can be misleading as to the actual problem or severity of the condition. In this case, a UPS general alarm came in after the loss of primary ac power to the UPS; however, the urgency was not understood as there was no apparent power system trouble.

It was not clear that the communication equipment was running on battery power until the RTU communication failed.

Is the Training Provided Adequate?
Even though new equipment may perform the same function as existing equipment at other locations on the system, new equipment may have features, operating modes, or alarm conditions that exceed similar existing equipment and are either not needed or affect the expected operation of the new equipment.

Lack of familiarity with the operation of this new equipment can lead people to expect it to respond similarly to those existing on the system.

In this case, the UPS system in question was a different make and model than that at other locations on the system and had only been operational for about 2 months.

Work Planning
When planning work that removes a power supply, the planner should know what loads are on that supply, which ones are critical loads, and how those critical loads would be supplied during a configuration change. Without knowledge of these aspects and/or the development of specific written work instructions or a checklist to coordinate the configuration change, much can be left to chance or dependent on individual human performance.

Corrective Actions

- The UPS system auto/manual restart switch at this facility was placed in the auto position.
- Future installations of similar UPS systems have been flagged to ensure correct auto/manual restart switch position selection prior to releasing equipment for regular service.
- Operating personnel have been counselled regarding deficiencies in the response to the UPS general alarm received on the day of the event.
- Mandatory operator response to alarms of this nature have been reinforced, including communication requirements.
- Training was conducted with operations personnel about the importance of the on-site UPS facilities and their impact on area RTUs.
- Training was provided about the locations of all on-site UPS facilities and their local alarm panels.
- Contacts for when UPS facility issues are encountered have been specifically identified and posted.

Lessons Learned

Commissioning

- When new equipment is commissioned and testing is performed by a contractor, the entity should ensure that the contractor's startup checklist includes all necessary settings, including switch positions. Otherwise, a latent error may set up part of the conditions necessary for a later failure.

Alarm False Sense of Security

- Assure that each alarm adequately describes the equipment or system operating status.
  - Sometimes alarm conditions have no immediate undesired consequence. This may lead to a false sense of security if the alarm does not adequately describe the equipment or system operating status.
  - As seen in this case, the RTU equipment continued to operate normally until the UPS battery ran out of power. It is likely that if the alarm actually stated that the UPS was operating on battery power that different actions would have been taken.
  - Properly categorize all alarms so that prioritized and proper action can be taken based on the significance of their cause.

When an Operating Event Is Assessed and Corrected

- Keep looking at the extent of the condition–look beyond the particular adverse event and inspect other areas of your system for similar issues.
  - Are there other pieces of equipment or systems that are new and may have a similar condition/trap in place?
- Periodically review your process for integrating new equipment onto the system. Work to remove any ambiguous meanings of alarming conditions for new equipment between both field and dispatch personnel about its operation.

When Planning Work that Removes an Important Power Supply

- The work planner should know what loads are on that supply (what could be lost?), which ones are critical loads (what absolutely needs to be kept powered?), and how those critical loads would be supplied during the configuration change.
- If there is a critical load or UPS that should automatically switchover to another source, include steps in the work instructions to verify that before turning off the normal source, that the alternate source is available. Then when the normal power is removed, check to ensure that the critical load or UPS does transfer over. If it does not do so automatically, then do it manually and then check that the alternate source is indeed powering it.

- If there is a “maintain positive control” policy to not trust auto transfers, then transfer to the other source manually before removing normal power.

NERC’s goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	WECC Event Analysis
Source of Lesson Learned:	Western Electric Coordinating Council
Lesson Learned #:	20180601
Date Published:	June 5, 2018
Category:	Transmission Facilities

This document is designed to convey lessons learned from NERC’s various activities. It is not intended to establish new requirements under NERC’s Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC’s Reliability Standards.

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Lesson Learned

External Model Data Causing State Estimator to Not Converge

Primary Interest Groups
Transmission Operators (TOPs)
Reliability Coordinators (RCs)
Transmission Owners (TOs) who operate an EMS with study/simulation capabilities

Problem Statement
Several entities in the Reliability*First (*RF) Region have experienced state estimator (SE) outages due to Inter-Control Center Communications Protocol (ICCP) data received from neighboring entities. Upon investigation, the topology of the neighboring system had changed but the recieving entities had not updated their representation so the ICCP data no longer matched with the older model. The SE was unable to converge (or solve).

Details
Upon receiving notification that the SE did not converge on its last run, the entities executed their emergency operation procedures to continue monitoring the system. According to these procedures, each entity advised their respective RC and neighboring TOPs so that they could help monitor the system and determine if there were new contingencies or overloads. The entity experiencing the issue then engaged Operations Support personnel (including IT personnel) to troubleshoot why the SE failed to solve. This process involves looking for internal and external data points that are either inaccurate, of bad data quality, or not correctly represented in the external model. Sometimes, vendors are engaged to help troubleshoot the issue and identify the bus or busses that may be the problem. In the examples used for this Lessons Learned document, an external entity was recieving good quality data through an ICCP link; however, because the external model was not accurate, the SE could not converge until either the data points were manually removed or adjusted or the model was fixed.

Corrective Actions
Upon determination that data points or external model were incorrect, there were several actions that allowed the SE to converge (not all methods were used by every entity nor in all cases):

- Removing the data points from the model to allow the SE to converge around the area, hopefully producing a quality solution.
- Phone calls were made to the RC or neighboring entities to assess the situation. It is possible that RTU or other communications-type maintenance may be the reason for the external data point to be invalid (or “bad”) even though its quality shows as good; however, often it is due to some type of external topology change outside of the entity’s footprint. Discuss topology with neighbors so the model can be adjusted as necessary.

- Some entities have the ability to freeze external data (either globally or for a specific area) and revert to the last known good solution. This allows the SE to converge while operations support personnel troubleshoot the external model and incoming data.
- Data bounds and limits were placed where possible on external data so as to throw away any unreasonable data points (e.g., hundreds of MVARs on a subtransmission transformer).
- Applying lower weighting to external measurements was used in some cases (not all EMS allows that method).
- Increase the number of measurements in unsolved areas of the model.

Lesson Learned

RCs and TOPs have expanded their EMS models to monitor the impact of events and outages outside of their footprint. This has increased potential exposure to bad data points, inaccurate topology modeling, and communication issues which may cause SE non-convergence events.

Changes to the BES (including new substations, other new facilities, and removed facilities) need to be communicated to neighboring entities far enough in advance so that they can update their external EMS models and ensure that the data received through ICCP links is accurately matched to the appropriate data points in the model.

- Models can be shared between the RC and its TOPs using standardized formats such as CIM, the Common Information Model.[1] Other than the TOP instituting a change, the RC is the next to know of a change to the topology of the system. This information can be communicated to all entities that include that area in their external model.
- Consider standardizing on model names for facilities. Due to different EMS vendors and platforms, different data points may be called different cryptic names (often truncated due to space limitiations). Standardization of these model names could help reduce confusion and lead to fewer SE outages.
- External models should have sufficient detail (topology and SCADA) or should have very little SCADA. Explicitly modeling without sufficient SCADA can lead to solution errors.
- Automatically importing external (topology and SCADA) data while convenient can lead to problems, especially when troubleshooting unsolved areas. Ensure that imports contain all the types of data and default assumptions expected by your system (normally open switches, market model deficiencies).

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

[1] EPRI has a Common Information Model Primer available.

For more information please contact:

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	RF – Event Analysis (via email)
Source of Lesson Learned:	ReliabilityFirst
Lesson Learned #:	20180602
Date Published:	June 5, 2018
Category:	Communications

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

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Lesson Learned

Back Office EMS Support Tools Impact Real-Time Situational Awareness

Primary Interest Groups
Transmission Owners (TOPs)
Reliability Coordinators (RCs)
Transmission Owners (TOs) who operate an EMS with study/simulation capabilities

Problem Statement
Upon receiving a call from its RC about a particular contingency, a registered entity identified that half of the contingency lists in the energy management system (EMS) list were disabled. This was due to a back-office study where the contingency list control display was opened and modified, inadvertently impacting the contingencies being displayed in the real-time environment.

Details
Upon receiving a call from the RC, the transmission System Operator discovered that contingency analysis results were not correct. They were receiving a valid time-stamp regarding a state estimator solution, but results for some of the contingencies were not being displayed. Upon investigation, the entity identified that half of the contingency lists were disabled. Re-initialization was performed to enable all of the contingency lists. The entity opened a ticket with the vendor to investigate why this happened.

Past EMS snapshots were reviewed to determine when the problem began. It was found that while running a back-office study, the tabular contingency analysis list was opened in a new window in the real-time environment rather than as part of the study environment. Because no one else had exclusive control of the real-time environment, this resulted in changes to the contingency list being made in the real-time case without any notification to the person running the study. If someone had control of or "locked" the real-time case prior to this study being run, the person running the study would have gotten a message that they were not in control of the real-time case and would have realized that they were working in the real-time case rather than in the study case. The operations support engineer making the changes to the contingency list did not realize that these changes were being made in the real-time case.

The EMS design did not have alarms to indicate when changes are made to real-time case without the user having proactively taken control of the real-time case or when contingency lists are disabled.

Corrective Actions
Because the lack of application seperation for study case vs real-time made the need to maintain the real-time case locked absolute, and this condition was not well understood, the registered entity trained its operations support staff regarding this issue. The EMS support staff have been instructed not to release control of the real-time case when they complete their work as changes can inadvertently be made to real-time case when no one has control of real-time case.

Lesson Learned

The Regions have seen other similar events where a study tool or simulation tool has impacted the real-time EMS environment. The test, study, and simulation tools often share functionality and data with the real-time EMS tool to closely mimic real-time conditions. The test, study, and simulation tools are used to test out new features and technology; apply patches and fixes; run near-term studies looking for thermal, voltage, or stability concerns; and train the operators on interesting scenarios, including some stress-cases. Because these tools look and feel the same and often share some common data links, there is a risk that the real-time EMS environment can be compromised by changes to the test, study, or simulation systems, or the persons making the changes thinks they are in a non-real-time environment when really he or she is making changes to the production environment. The following controls may be implemented to help prevent, detect, and correct this risk:

- Build a separate Quailty Assurance (QA) or testing environment for back-office study.
- Discuss any vulnerabilities with the EMS vendor. What changes made to the test, study, or simulation tools could have consequences in the real-time environment?
- When possible, use different visual effects, such as different colored borders or backgrounds, to help operations support personnel differentiate between the real-time EMS environment and test, study, or simulation environment and know which applications they are using.
- Train operations support personnel and transmission System Operators on the risks of any setting changes or contingency list updates made to any of these environments.
- Provide clear guidelines on who is authorized to work in which environment and which study clones are assigned to which operators or support personnel. Ensure there is no overlap where two or more persons could be working on the same study in real-time applications.
- Work with internal EMS IT expertise or the vendor to design/assign application/environment permissions (read, write, modify) to support personnel and transmission System Operators. (Ideally, back office studies should only have read access to the data with no easy toggle between real-time and simulation tools.)
- Continue to work with Reliability Coordinators and Transmission Operators who have overlapping coverage of the entity's system. If the observations of the RC or the TOP differ from the registered entity's observations, investigate whether the differences in observations are the result of inadvertent disabling of tools or features.
- When performing start-up testing of any new EMS technology applications, carefully monitor other EMS tools and applications to ensure that the new application is not impacting the other systems.
- Ensure that opening and closing breakers in the simulation tool is not capable of opening and closing breakers in the production server (this avoids surprises when running drills and simulations).

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

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For more Information please contact:

NERC – Lessons Learned (via email)	RF – Event Analysis (via email)
Source of Lesson Learned:	ReliabilityFirst
Lesson Learned #:	20180603
Date Published:	June 5, 2018
Category:	Communications

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Technical Conference Docket No. AD18-11-000

NOTICE OF TECHNICAL CONFERENCE

(February 27, 2018)

Take notice that the Federal Energy Regulatory Commission (Commission) will hold a Technical Conference on Tuesday, July 31, 2018, from 9:00 AM to 5:00 PM. This Commissioner-led conference will be held in the Commission Meeting Room at the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426. The purpose of the conference is to discuss policy issues related to the reliability of the Bulk-Power System. The Commission will issue an agenda at a later date in a supplemental notice.

The conference will be open for the public to attend. There is no fee for attendance. However, members of the public are encouraged to preregister online at: https://www.ferc.gov/whats-new/registration/07-31-18-form.asp.

Those wishing to be considered for participation in panel discussions should submit nominations no later than close of business on March 23, 2018 online at: https://www.ferc.gov/whats-new/registration/07-31-18-speaker-form.asp.

Information on this event will be posted on the Calendar of Events on the Commission's website, http://www.ferc.gov, prior to the event. The conference will also be webcast and transcribed. Anyone with Internet access who desires to listen to this event can do so by navigating to the Calendar of Events at http://www.ferc.gov and locating this event in the Calendar. The event will contain a link to the webcast. The Capitol Connection provides technical support for webcasts and offers the option of listening to the meeting via phone-bridge for a fee. If you have any questions, visit http://www.CapitolConnection.org or call (703) 993-3100. Transcripts of the technical conference will be available for a fee from Ace-Federal Reporters, Inc. at (202) 347-3700.

Commission conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations, please send an email to accessibility@ferc.gov or call toll free 1 (866) 208-3372 (voice) or (202) 502-8659 (TTY), or send a fax to (202) 208-2106 with the required accommodations.

For more information about this technical conference, please contact Lodie White (202) 502-8453, Lodie.White@ferc.gov. For information related to logistics, please contact Sarah McKinley at (202) 502-8368, Sarah.Mckinley@ferc.gov.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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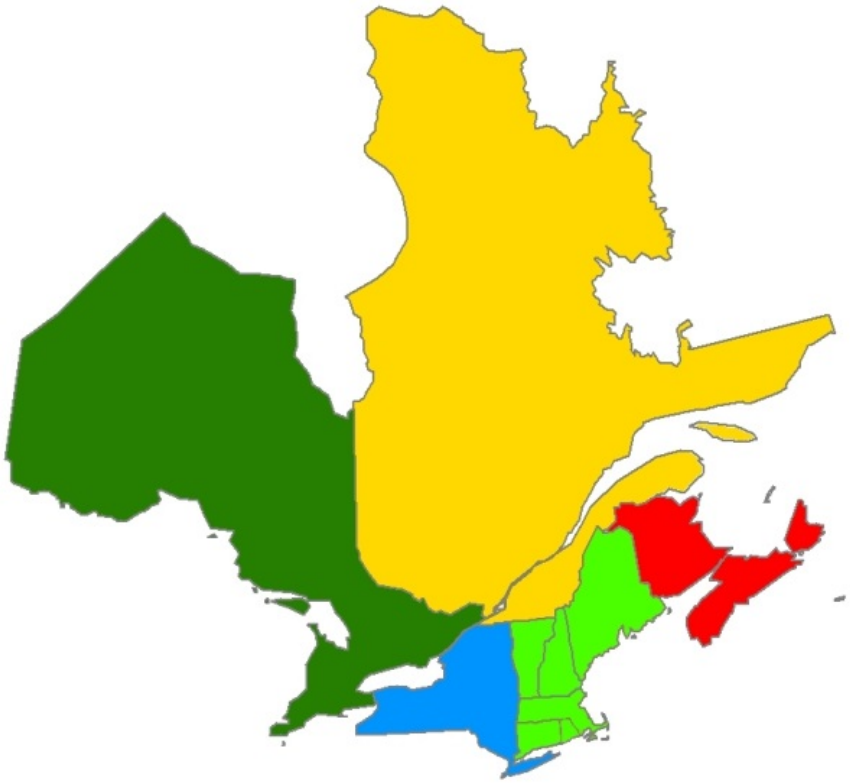
Northeast Power Coordinating Council, Inc. (NPCC)

2019 Business Plan and Budget



Draft #1
Submitted to NERC May 2, 2018

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Introduction

Total NPCC Resources (in whole dollars)	2019 Budget	U.S.	Canada	Mexico
Regional Entity Division FTEs	38.86			
Criteria Services Division FTEs	2.14			
Total FTEs	**41.0**			
Regional Entity Division Expenses	$15,901,955			
Criteria Services Division Expenses	$1,095,510			
Total Expenses	**$16,997,465**			
Regional Entity Division Inc(Dec) in Fixed Assets	**($99,000)**			
Criteria Services Division Inc(Dec) in Fixed Assets	**$14,000**			
Total Inc(Dec) in Fixed Assets	**($85,000)**			
Regional Entity Division Working Capital Requirement**	**($732,933)**			
Criteria Services Division Working Capital Requirement***	**($49,749)**			
Total Working Capital Requirement	**($782,682)**			
Total Regional Entity Division Funding Requirement	$15,070,022			
Total Criteria Services Division Funding Requirement	$1,059,761			
Total Funding Requirement	**$16,129,783**			
Regional Entity Division Assessments	**$15,002,522**	$XXX,XXX	$XXX,XXX	
Regional Entity Division Assessments Percentage	**100.0%**	XX.X%	XX.X%	
Criteria Services Division Membership Fees	**$1,059,761**	$XXX,XXX	$XXX,XXX	
Total NPCC Assessments & Membership Fees	**$16,062,283**	$XXX,XXX	$XXX,XXX	
NEL	XX	XX	XX	
NEL %	100%	XX.XX%	XX.XX%	

** Refer to Table B-1 on page 56 in Section B.
*** Refer to the Reserve Analysis on page 73 in Section C.

2019 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 budget and assessments by 4.6% comprising a Regional Entity increase of 4.6% and a Criteria Services division increase of 4.0%. The proposed 2019 funding requirements will be satisfied by a Regional Entity division assessment of $15,002,522 and Criteria Services division fees of $1,059,761, for a total of $16,062,283. The total NPCC assessments and fees represent an increase of 4.6% compared to the 2018 total assessments and fees of $15,360,927. NPCC believes that the Region remains an effective provider of Regional Entity and Criteria Services division functions. NPCC's corporate culture centers on consistent delivery of excellent results at a cost that is considerate of the longstanding tradition in the Northeast of affordable and reliable electricity.

Organizational Overview

Northeast Power Coordinating Council, Inc. (NPCC) is a 501(c)(6) not-for-profit corporation in the state of New York responsible for promoting and improving the reliability of the international, interconnected bulk power systems in Northeastern North America through (i) the development of Regional Reliability Standards and compliance assessment and enforcement of continent-wide and Regional Reliability Standards, coordination of system planning, design and operations, and assessment of reliability (collectively, Regional Entity activities), and (ii) the establishment of Regionally-specific criteria, and monitoring and enforcement of compliance

with such criteria (collectively, Criteria Services activities). NPCC provides the functions and services for Northeastern North America of a cross-border Regional Entity through a Regional Entity division, as well as Regionally-specific Criteria Services for Northeastern North America through a Criteria Services division. NPCC's website is www.npcc.org.

The NPCC Region covers nearly 1.2 million square miles and is populated by more than 56 million people. NPCC U.S. includes the six New England states and the state of New York. NPCC Canada includes the provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. In total, from a net energy for load perspective, NPCC is approximately 45% U.S. and 55% Canadian. With regard to Canada, approximately 70% of Canadian net energy for load is within the NPCC Region.

Effective January 1, 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 2019 targeted staffing level of 41 power industry professionals and support personnel. Details of the 2019 business plans and budget for each program area are included in Section A for the Regional Entity division. The 2019 Regional Entity division schedules are shown in Section B. Section C details the 2019 Criteria Services division business plan and budget.

Membership and Governance

NPCC monitors approximately 213 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 Federal Energy Regulatory Commission ("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.

2019 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 2019 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.

Regional Entity Division Functional Scope

NPCC's Regional Entity division functions in support of the ERO include:

- Active participation in the development of North American Reliability Standards for the bulk electric system, and as needed development of Reliability Standards applicable within the NPCC cross-border Regional Entity.
- Monitoring and enforcement of approved Reliability Standards, including the registration of responsible entities, and as needed certification of such entities.
- Assessment of the present and future reliability of the bulk power system.
- Operational coordination and situation awareness support.
- Event analysis and identifying lessons learned to improve reliability.
- Effective training and education of reliability personnel.
- Promoting the protection of critical electric infrastructure.

In recognition of the delegated compliance role of Regional Entities as an important means to enhancing reliability, NPCC has designated a significant percentage of its staff resources to compliance monitoring and enforcement. NPCC has also developed and deployed a robust set of online tools for gathering data, analysis, and tracking of compliance information to support its ability to carry out its responsibilities in a cost effective manner.

NPCC has organized the remaining staff into program areas consistent with EPAct 2005 to address the other functions listed above. These experts in operations, planning and reliability analysis assist registered entities in assessing and improving reliability. It is in support of these areas that NPCC engages the majority of industry experts on its technical committees.

2019 Overview of Regional Entity Division Cost Impacts

The proposed Regional Entity division assessment of $15,002,522, to support the Regional Entity division budget of $15,802,522, is an increase of 4.6% compared to the 2018 assessment of $14,341,787.

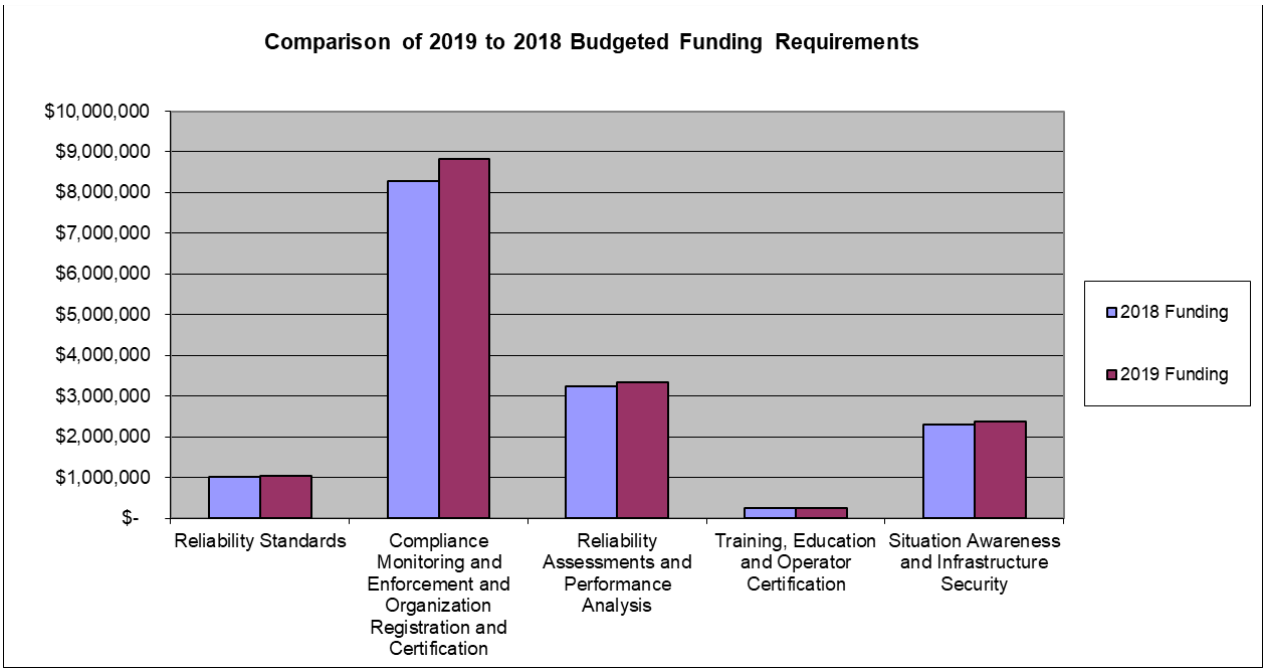
2018 Projections

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. 2018 Projections reflect expectations based on the first quarter variance report. It is anticipated that projections could change throughout 2018 and would be reflected in each subsequent quarter's variance report.

Summary by Program

Program	Budget 2018	Projection 2018	Budget 2019	Variance 2019 Budget v 2018 Budget	Variance %
Reliability Standards	$ 1,010,246	$ 1,010,246	$ 1,035,329	$ 25,083	2.5%
Compliance Monitoring and Enforcement and Organization Registration and Certification	$ 8,293,748	$ 8,110,648	$ 8,816,154	$ 522,406	6.3%
Reliability Assessments and Performance Analysis	$ 3,240,721	$ 3,390,721	$ 3,332,503	$ 91,783	2.8%
Training, Education and Operator Certification	$ 249,051	$ 249,051	$ 252,440	$ 3,389	1.4%
Situation Awareness and Infrastructure Security	$ 2,313,202	$ 2,313,202	$ 2,366,528	$ 53,326	2.3%
Total	$ 15,106,967	$ 15,073,867	$ 15,802,955	$ 695,988	4.6%

This chart does not include allocation of working capital requirements among the Program Areas.



This chart does not include allocation of working capital requirements among the Program Areas.

Personnel Analysis

Total FTE's by Program Area	Budget 2018	Projection 2018	Direct FTEs 2019 Budget	Shared FTEs[1] 2019 Budget	Total FTEs 2019 Budget	Change from 2018 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	16.00	16.50	17.00	0.00	17.00	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	5.33	4.90	0.93	5.83	0.00
Situation Awareness and Infrastructure Security	5.00	5.00	5.00	0.00	5.00	0.00
Total FTEs Operational Programs	**28.86**	**28.86**	**28.00**	**1.86**	**29.86**	**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	0.00	2.50	0.00
Information Technology	2.00	2.00	2.00	0.00	2.00	0.00
Legal and Regulatory	1.00	1.00	1.00	0.00	1.00	0.00
Human Resources	1.00	1.00	1.00	0.00	1.00	0.00
Accounting and Finance	1.00	1.00	2.00	0.00	2.00	1.00
Total FTEs Administrative Programs	**8.00**	**8.00**	**9.00**	**0.00**	**9.00**	**1.00**
Total FTEs	**36.86**	**36.86**	**37.00**	**1.86**	**38.86**	**2.00**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

2018 Budget and Projection and 2019 Budget Comparisons

Statement of Activities and Capital Expenditures
2018 Budget & Projection, and 2019 Budget

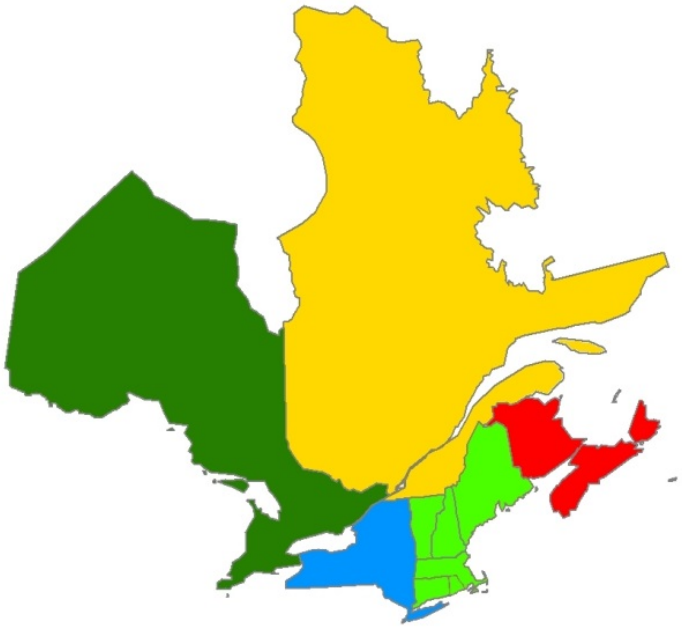
REGIONAL ENTITY DIVISION

	2018 Budget	2018 Projection	Variance[2] 2018 Projection v 2018 Budget Over(Under)	2019 Budget	Variance 2019 Budget v 2018 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 14,341,787	$ 14,341,787	$ -	$ 15,002,522	$ 660,735
Penalty Sanctions[1]	75,000	75,000	-	-	(75,000)
Total ERO Funding	**$ 14,416,787**	**$ 14,416,787**	**$ -**	**$ 15,002,522**	**$ 585,735**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	64,000	64,000	-	67,500	3,500
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 14,480,787**	**$ 14,480,787**	**$ -**	**$ 15,070,022**	**$ 589,235**
Expenses					
Personnel Expenses					
Salaries	$ 7,107,599	$ 6,937,599	$ (170,000)	$ 7,332,280	$ 224,681
Payroll Taxes	411,440	406,440	(5,000)	449,994	38,553
Benefits	1,476,378	1,472,378	(4,000)	1,613,078	136,700
Retirement Costs	825,353	792,353	(33,000)	853,511	28,157
Total Personnel Expenses	**$ 9,820,770**	**$ 9,608,770**	**$ (212,000)**	**$ 10,248,862**	**$ 428,092**
Meeting Expenses					
Meetings	$ 353,050	$ 353,050	$ -	$ 370,750	$ 17,700
Travel	834,500	834,500	-	845,900	11,400
Conference Calls	37,000	37,000	-	36,000	(1,000)
Total Meeting Expenses	**$ 1,224,550**	**$ 1,224,550**	**$ -**	**$ 1,252,650**	**$ 28,100**
Operating Expenses					
Consultants & Contracts	$ 1,877,640	$ 2,027,640	$ 150,000	$ 2,022,150	$ 144,510
Office Rent	810,700	810,700	-	820,700	10,000
Office Costs	664,760	664,760	-	676,347	11,587
Professional Services	960,000	960,000	-	978,000	18,000
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	50,000	50,000	-	51,000	1,000
Depreciation	269,000	269,000	-	269,000	-
Total Operating Expenses	**$ 4,632,100**	**$ 4,782,100**	**$ 150,000**	**$ 4,817,197**	**$ 185,097**
Total Direct Expenses	**$ 15,677,420**	**$ 15,615,420**	**$ (62,000)**	**$ 16,318,709**	**$ 641,289**
Indirect Expenses	**$ (416,453)**	**$ (416,453)**	**$ -**	**$ (416,755)**	**$ (302)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 15,260,967**	**$ 15,198,967**	**$ (62,000)**	**$ 15,901,955**	**$ 640,988**
Change in Assets	**$ (780,180)**	**$ (718,180)**	**$ 62,000**	**$ (831,933)**	**$ (51,753)**
Fixed Assets					
Depreciation	$ (269,000)	$ (269,000)	$ -	$ (269,000)	$ -
Computer & Software CapEx	115,000	115,000	-	170,000	55,000
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	0	0	-	-	(0)
Inc(Dec) in Fixed Assets (C)	**(154,000)**	**(154,000)**	**-**	**(99,000)**	**55,000**
TOTAL BUDGET (=B+C)	**$ 15,106,967**	**$ 15,044,967**	**$ (62,000)**	**$ 15,802,955**	**$ 695,988**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (626,180)**	**$ (564,180)**	**$ 62,000**	**$ (732,933)**	**$ (106,753)**

(1) $0 of penalty sanctions collected to date and prior to June 30, 2018.

(2) 2018 Projections reflect expectations based on the 1st quarter statement of activities. It is anticipated that projections could change throughout 2018 and would be reflected in each subsequent quarter's statement of activities.

Section A – Regional Entity Division
2019 Business Plan and Budget



Section A — 2019 Regional Entity Division Business Plan and Budget

Reliability Standards Program

Reliability Standards Program Resources (in whole dollars)	2018 Budget	2019 Budget	Increase (Decrease)
Total FTEs	1.93	1.93	0.00
Direct Expenses	$647,633	$665,870	$18,237
Indirect Expenses	$375,586	$375,858	$272
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($12,974)	($6,399)	$6,575
Total Funding Requirement	$1,010,246	$1,035,329	$25,083

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 and the ERO Enterprise Long-Term Strategy. 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. NPCC supports the ERO efforts to develop reliability standards in a timely and efficient manner and which are 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. In addition, the NPCC Reliability Standards Program Area provides oversight to ensure that NPCC Regional Reliability Criteria contained in the form of Directories, are developed 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 NPCC Member agreements and various tariffs, and interconnection agreements, and 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.

2019 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 recommendation 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 Reliability Standards, any associated Regional Reliability Standards 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 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. Creation of variances to NERC 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).
- The number of NERC and Regional standards interpretations is expected to remain low. However, implementation guidance 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 duplicity to the ERO standards.

2019 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 using the "Cost of Risk Reduction Analysis" (CRRA) process 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 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 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.
- 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 RISC activities and 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, 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 impacts to the BES as a result of DER penetration.
- Identify opportunities to improve resilience of the BES.
- Identify and coordinate reliability 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 Periodic Review Standing Team activities.
- Identify opportunities and processes for cost-effectiveness CRRA analysis activities to determine the need to revise a standard during the PR process.
- 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.

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
2018 Budget & Projection, and 2019 Budget

Reliability Standards

	2018 Budget	2018 Projection	Variance 2018 Projection v 2018 Budget Over(Under)	2019 Budget	Variance 2019 Budget v 2018 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 1,005,230	$ 1,005,230	$ -	$ 1,035,329	$ 30,099
Penalty Sanctions	5,016	5,016	-	-	(5,016)
Total ERO Funding	**$ 1,010,246**	**$ 1,010,246**	**$ -**	**$ 1,035,329**	**$ 25,083**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 1,010,246**	**$ 1,010,246**	**$ -**	**$ 1,035,329**	**$ 25,083**
Expenses					
Personnel Expenses					
Salaries	$ 377,093	$ 377,093	$ -	$ 382,872	$ 5,779
Payroll Taxes	21,390	21,390	-	22,735	1,346
Benefits	98,851	98,851	-	106,764	7,912
Retirement Costs	40,299	40,299	-	41,599	1,300
Total Personnel Expenses	**$ 537,633**	**$ 537,633**	**$ -**	**$ 553,970**	**$ 16,337**
Meeting Expenses					
Meetings	$ 7,000	$ 7,000	$ -	$ 7,000	$ -
Travel	93,000	93,000	-	94,900	1,900
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 100,000**	**$ 100,000**	**$ -**	**$ 101,900**	**$ 1,900**
Operating Expenses					
Consultants & Contracts	$ 10,000	$ 10,000	$ -	$ 10,000	$ -
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 10,000**	**$ 10,000**	**$ -**	**$ 10,000**	**$ -**
Total Direct Expenses	**$ 647,633**	**$ 647,633**	**$ -**	**$ 665,870**	**$ 18,237**
Indirect Expenses	**$ 375,586**	**$ 375,586**	**$ -**	**$ 375,858**	**$ 272**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 1,023,220**	**$ 1,023,220**	**$ -**	**$ 1,041,728**	**$ 18,509**
Change in Assets	**$ (12,974)**	**$ (12,974)**	**$ -**	**$ (6,399)**	**$ 6,575**
Fixed Assets					
Depreciation	$ -	-	$ -	-	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(12,974)	(12,974)	-	(6,399)	6,575
Inc(Dec) in Fixed Assets (C)	**(12,974)**	**(12,974)**	**-**	**(6,399)**	**6,575**
TOTAL BUDGET (=B+C)	**$ 1,010,246**	**$ 1,010,246**	**$ -**	**$ 1,035,329**	**$ 25,083**
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)	2018 Budget	2019 Budget	Increase (Decrease)
Total FTEs	16.00	17.00	1.00
Direct Expenses	$5,247,634	$5,561,849	$314,216
Indirect Expenses	$3,113,668	$3,310,668	$197,000
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($67,554)	($56,363)	$11,191
Total Funding Requirement	$8,293,748	$8,816,154	$522,406

Program Scope and Functional Description

The Compliance Monitoring and Enforcement and Organization Registration and Certification Program (CORC) Program scope covers:

1) the identification, registration and certification of those entities responsible for meeting the NERC Reliability Standards and any approved Regional Standards;
2) the implementation of the risk-based NERC Compliance Monitoring and Enforcement Program (CMEP) in the United States, including the compliance monitoring, assessment and enforcement of NERC Reliability Standards and Regional Reliability Standards;
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, 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, NPCC's compliance staff is divided into four sub-program areas: Compliance Implementation, Registration, and Certification; Compliance Entity Risk Assessment; Compliance Monitoring; and Compliance Enforcement.

Compliance Implementation, Registration and Certification

The Compliance Implementation and Registration 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 Implementation and Registration 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),
- Responds to any Complaints submitted to NPCC,
- Maintains NPCC's compliance portal and compliance tracking system, and;
- Conducts outreach, training, and education as necessary to support the implementation of Reliability Standards.

Compliance Entity Risk Assessment

The Compliance Entity Risk Assessment sub-program area is responsible for assessing the inherent risk and internal controls of registered entities. The Compliance Entity Risk Assessment sub-program area:

- Conducts Inherent Risk Assessments (IRA) on registered entities,
- Conducts Internal Controls Evaluations (ICE) on volunteering registered entities,
- Assists with the development of the annual implementation plans, and;
- Provides the basis for each registered entity's Compliance Oversight Plan.

Compliance Monitoring

The Compliance Monitoring sub-program area is responsible for conducting all compliance monitoring activities. The Compliance Monitoring sub-program area is focused on the most significant risks to the BES. The Compliance Monitoring 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 Enforcement

The 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 Enforcement sub-program area:

- Determines the relevant facts and circumstances necessary to understand each non-compliance,
- Evaluates and assigns a risk level to each non-compliance,
- Evaluates and approves the mitigation activities or Mitigation Plan for each non-compliance,
- Assesses the relevant compliance history for each non-compliance,
- Determines the disposition method for each non-compliance, and
- Evaluates registered entities for the self-logging program.

2019 Key Assumptions and Cost Impacts

2018	Projected 2019
4 On-Site Audits	7 On-Site O&P Audits
10 On-Site CIP Audits	10 On-Site CIP Audits
30 Off-Site Audits	30 Off-Site O&P Audits
15 Off-Site CIP Audits	15 Off-Site CIP Audits
15 Spot Checks	10 Spot Checks
25 Guided self-certifications	25 Guided self-certifications
50 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
120 Violations (Estimated)	225 Violations (Estimated)
Settlements Covering 50 Violations	Settlements Covering 80 Violations
2 Hearings (Unbudgeted)	2 Hearings (Unbudgeted)
1 CI (Estimated)	1 CI (Estimated)
2 Entity Certifications	2 Entity Certifications

- Audit costs will increase slightly in 2019 from 2018. NPCC predicts three additional on-site audits for 2019.
- Potential increases in 2019 due to the continuation of monitoring and enforcement activities related to implementing the QCMEP in Québec and the NB CMEP in New Brunswick.
- The 2019 Business Plan projects increases in Enforcement Processing activities over the 2018 Budget. It is expected that the increase in violation processing will continue in 2019. For the first time, in late 2018, low impact cyber systems will be in scope for compliance in most jurisdictions and the medium and high impact cyber systems will be in scope for compliance in Quebec.
- The 2019 Business Plan projects the need for one Compliance Investigation. These Compliance Investigations are manpower intensive for NPCC staff (requiring allocation of more resources and potentially higher than normal costs).

2019 Goals and Key Deliverables

- Conduct scheduled compliance monitoring and enforcement activities pursuant to the 2019 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.
- Implement compliance responsibilities in Canada based on the regulatory structure specific to each jurisdiction.
- Evaluate monitoring, violation processing, risk-assessment, registration and certification program for sufficiency and effectiveness. Modify as needed.
- Collaborate with the ERO Enterprise to develop common and consistent CMEP 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.
- Conduct 2019 Compliance Engagement Schedule based on risk to the BES 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.
- Implement physical security outreach and cyber security outreach by visiting registered entity sites to perform an assessment of their physical security, evaluate their cyber security and supply recommendations for improvements.
- Continue to perform comprehensive enforcement investigations to determine the relevant facts and circumstances necessary to understand each non-compliance, assess the risk, and evaluate the mitigation activities or Mitigation Plan for each non-compliance. 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 non-compliance, 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.
- Continue to promote practices to enhance the benefits of the self-reporting of violations by the registered entity. This could include the emphasis on the benefits of a registered entity improving its internal processes used for identifying and submitting self-reports, improvement in the way Regional Entities process self-reports, and the streamlining and standardizing of the amount and type of data needed to evaluate a self-report.

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 53% of its resources on this activity.

Resource Requirements

Personnel

- One additional FTE to increase in-house expertise rather than utilizing an additional contractor. The increase in personnel expenses will be partially offset by a lesser increase in Consultants and Contracts than without this FTE addition.

Consultants and Contracts

- Increase in consultants and contracts associated with an ERO Enterprise-wide increase in audit activity.

Fixed Assets

- No new functionality is planned for the Compliance Issues Tracking System and CMEP Data Administration Application at this time.

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 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
2018 Budget & Projection, and 2019 Budget
Compliance Monitoring and Enforcement and Organization Registration and Certification

	2018 Budget	2018 Projection	Variance 2018 Projection v 2018 Budget Over(Under)	2019 Budget	Variance 2019 Budget v 2018 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 7,692,569	$ 7,692,569	$ -	$ 8,183,282	$ 490,713
Penalty Sanctions	41,580	41,580	-	-	(41,580)
Total ERO Funding	**$ 7,734,149**	**$ 7,734,149**	**$ -**	**$ 8,183,282**	**$ 449,133**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 7,734,149**	**$ 7,734,149**	**$ -**	**$ 8,183,282**	**$ 449,133**
Expenses					
Personnel Expenses					
Salaries	$ 2,716,635	$ 2,565,935	$ (150,700)	$ 2,815,882	$ 99,247
Payroll Taxes	171,841	168,841	(3,000)	191,849	20,008
Benefits	524,801	521,801	(3,000)	585,543	60,742
Retirement Costs	282,356	255,956	(26,400)	301,025	18,669
Total Personnel Expenses	**$ 3,695,634**	**$ 3,512,534**	**$ (183,100)**	**$ 3,894,299**	**$ 198,666**
Meeting Expenses					
Meetings	$ 9,000	$ 9,000	$ -	$ 15,000	$ 6,000
Travel	289,000	289,000	-	295,400	6,400
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 298,000**	**$ 298,000**	**$ -**	**$ 310,400**	**$ 12,400**
Operating Expenses					
Consultants & Contracts	$ 1,254,000	$ 1,254,000	$ -	$ 1,357,150	$ 103,150
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 1,254,000**	**$ 1,254,000**	**$ -**	**$ 1,357,150**	**$ 103,150**
Total Direct Expenses	**$ 5,247,634**	**$ 5,064,534**	**$ (183,100)**	**$ 5,561,849**	**$ 314,216**
Indirect Expenses	**$ 3,113,668**	**$ 3,113,668**	**$ -**	**$ 3,310,668**	**$ 197,000**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 8,361,302**	**$ 8,178,202**	**$ (183,100)**	**$ 8,872,517**	**$ 511,215**
Change in Assets	**$ (627,153)**	**$ (444,053)**	**$ 183,100**	**$ (689,235)**	**$ (62,082)**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	40,000	40,000	-	-	(40,000)
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(107,554)	(107,554)	-	(56,363)	51,191
Inc(Dec) in Fixed Assets (C)	**(67,554)**	**(67,554)**	**-**	**(56,363)**	**11,191**
TOTAL BUDGET (=B+C)	**$ 8,293,748**	**$ 8,110,648**	**$ (183,100)**	**$ 8,816,154**	**$ 522,406**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (559,599)**	**$ (376,499)**	**$ 183,100**	**$ (632,872)**	**$ (73,273)**

Reliability Assessment and Performance Analysis Program

Reliability Assessment and Performance Analysis Program Resources (in whole dollars)	2018 Budget	2019 Budget	Increase (Decrease)
Total FTEs	5.83	5.83	0.00
Direct Expenses	$2,145,368	$2,216,468	$71,101
Indirect Expenses	$1,134,543	$1,135,364	$821
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($39,190)	($19,329)	$19,861
Total Funding Requirement	$3,240,721	$3,332,503	$91,783

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 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.

2019 Key Focus Areas

In collaboration with NERC, Key Focus Area activities for 2019 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

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 of ERO Goals 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 five Eastern Interconnection Regional Entities, and acts as the liaison between the ERAG MMWG and the NPCC SS-37 Working Group.

ERAG Committee Activities 2019 Goals and Deliverables

- 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.
- 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.
- Continue discussions with Eastern Interconnection Planning Collaborative (EIPC) regarding proposed transition of the Eastern Interconnection steady state and dynamics base case development role as the MOD-032, Requirement R4 Designee.

Multi-Regional Modeling Working Group 2019 Goals and Deliverables

- Facilitate the completion of the steady state and dynamic simulation base case data compilation and development for the 2019 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 ERAG 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 2019 Goals and Deliverables

- Conduct the 2019 ERAG Assessment and 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. At least one NPCC Exception Request will require recertification in 2019; analysis of an Exception Request from a New Brunswick entity is expected to continue into 2019.

2019 NERC Activities

NPCC will provide the Regional perspective with appropriate NPCC RAPA staff participation on selective NERC Planning and Operating Committees and key related NERC Subcommittees, Task Forces and Working Groups, including:

- Load Modeling Task Force;
- System Protection and Control Subcommittee;
- Demand Response Availability Data System Working Group;
- Generating Availability Data System Working Group;
- Transmission Availability Data System Working Group;
- Power Plant Model Verification Task Force;
- Reliability Assessment Subcommittee;
- Probabilistic Assessment Working Group;
- System Analysis and Modeling Subcommittee;
- Synchronized Measurement Subcommittee;
- Event Analysis Subcommittee;
- Performance Analysis Subcommittee; and,
- Misoperation Information Data Analysis System.

ERO – Executive Management Group (EMG) 2019 Activities

Provide analytic support for the ERO-EMG:

- Operations Leadership Team;
- Bulk Electric System Exception Process Working Group;
- ERO-RAPA Group; and,
- Other activities as directed by the ERO-Executive Management Group.

2019 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 2019 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.
- Lead the NPCC Task Forces in the completion of the review and revision the *A-10 Criteria– NPCC Classification of Bulk Power System Elements*.
- 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 2019 Goals and Deliverables

- Review and recommend approval of Area Transmission Reviews.
- Review and classify new and modified Special Protection Systems and/or 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.
- Update the NPCC Electric System Map.
- Annually develop a library of power flow base cases and associated dynamic cases.
- 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 2019 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.
- Review and analyze misoperations of protection systems and Remedial Action Schemes/Special Protection Systems as they occur in the NPCC Region.
- 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 2019 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.
- 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.

- Perform a voluntary Critical Operating Tool Analysis Survey accompanied with the previous surveys recommendation to disseminate and assess the implementation of best practices and recommendations.

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 2019 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).
- 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 22% of its resources on these activities.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2019.

Consultants and Contracts

- Increase in consultants and contracts expense is associated with increase in inherent risk and emerging risk reliability studies.

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
2018 Budget & Projection, and 2019 Budget
Reliability Assessment and Performance Analysis

	2018 Budget	2018 Projection	Variance 2018 Projection v 2018 Budget Over(Under)	2019 Budget	Variance 2019 Budget v 2018 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 3,225,570	$ 3,225,570	$ -	$ 3,332,503	$ 106,933
Penalty Sanctions	15,151	15,151	-	-	(15,151)
Total ERO Funding	**$ 3,240,721**	**$ 3,240,721**	**$ -**	**$ 3,332,503**	**$ 91,783**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 3,240,721**	**$ 3,240,721**	**$ -**	**$ 3,332,503**	**$ 91,783**
Expenses					
Personnel Expenses					
Salaries	$ 1,106,772	$ 1,106,772	$ -	$ 1,135,264	$ 28,491
Payroll Taxes	65,805	65,805	-	69,027	3,222
Benefits	220,007	220,007	-	219,655	(352)
Retirement Costs	117,144	117,144	-	123,322	6,179
Total Personnel Expenses	**$ 1,509,728**	**$ 1,509,728**	**$ -**	**$ 1,547,268**	**$ 37,541**
Meeting Expenses					
Meetings	$ 22,000	$ 22,000	$ -	$ 23,000	$ 1,000
Travel	212,000	212,000	-	216,200	4,200
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 234,000**	**$ 234,000**	**$ -**	**$ 239,200**	**$ 5,200**
Operating Expenses					
Consultants & Contracts	$ 401,640	$ 551,640	$ 150,000	$ 430,000	$ 28,360
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 401,640**	**$ 551,640**	**$ 150,000**	**$ 430,000**	**$ 28,360**
Total Direct Expenses	**$ 2,145,368**	**$ 2,295,368**	**$ 150,000**	**$ 2,216,468**	**$ 71,101**
Indirect Expenses	**$ 1,134,543**	**$ 1,134,543**	**$ -**	**$ 1,135,364**	**$ 821**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 3,279,911**	**$ 3,429,911**	**$ 150,000**	**$ 3,351,833**	**$ 71,922**
Change in Assets	**$ (39,190)**	**$ (189,190)**	**$ (150,000)**	**$ (19,329)**	**$ 19,861**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(39,190)	(39,190)	-	(19,329)	19,861
Inc(Dec) in Fixed Assets (C)	**(39,190)**	**(39,190)**	**-**	**(19,329)**	**19,861**
TOTAL BUDGET (=B+C)	3,240,721	3,390,721	150,000	3,332,503	91,783
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ 0**	**$ (150,000)**	**$ (150,000)**	**$ 0**	**$ (0)**

Training, Education, and Operator Certification Program

Training, Education, and Operator Certification Program Resources (in whole dollars)	2018 Budget	2019 Budget	Increase (Decrease)
Total FTEs	0.10	0.10	0.00
Direct Expenses	$230,263	$233,297	$3,034
Indirect Expenses	$19,460	$19,475	$14
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($672)	($332)	$341
Total Funding Requirement	$249,051	$252,440	$3,389

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 operator from PJM have been regular participants at past seminars. Examples of specific topics addressed at recent seminar 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;
- training techniques and methods;
- evaluation of new techniques and 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" and "Acquire, engage, develop, and retain highly qualified talent with requisite technical expertise to execute the ERO Enterprise's statutory functions."

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 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 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; and,
- 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 the system operator's awareness and knowledge of the standards, criteria and procedures they apply in real time operation.
- Provide more sharing of new training approaches, exchange of information on internal methods of system operator selection, training material and training sessions;
- Enhance efficiency and cost savings in the training programs in the NPCC 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. The sharing of approaches used by some NPCC Areas to address any changes needed to existing system operator training programs due to PER-005-2 requirements is valuable to CO-2 Working Group members.
- NPCC will conduct two Standards and Compliance workshops in 2018, 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).

2019 Key Assumptions

NPCC regularly conducts seminars as well as Spring and Fall Standards and Compliance workshops specifically designed, primarily through the conduct of targeted breakout classroom sessions and presentations on current industry related activities, to provide for the most efficient exchange of information between the NPCC Compliance and Standards staff and the NPCC Stakeholders. Presentations in the past have been conducted by FERC, NERC and Stakeholder representatives in addition to NPCC staff members. To supplement these workshops, NPCC develops webinars that will focus on specific topics pertinent to developments related to compliance program implementation, standards development or technical issues.

NPCC regularly conducts Spring and Fall System Operator Seminars. These seminars involve system operators from the NPCC RC/BA Areas and PJM, and are held in early May and early November.

Training, Education and Operator Certification 2019 Goals and Deliverables

- Prepare and conduct the 2019 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 Standard PER-005, "*System Personnel Training.*"
- Develop on-line operational training webinars that focus on specific topics pertinent to compliance program implementation, standards development or technical issues.

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

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2019.

Training, Education, and Operator Certification Program

Funding sources and related expenses for the training, education, and operator certification 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
2018 Budget & Projection, and 2019 Budget
Training, Education, and Operator Certification

	2018 Budget	2018 Projection	Variance 2018 Projection v 2018 Budget Over(Under)	2019 Budget	Variance 2019 Budget v 2018 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 184,791	$ 184,791	$ -	$ 184,940	$ 149
Penalty Sanctions	260	260	-	-	(260)
Total ERO Funding	**$ 185,051**	**$ 185,051**	**$ -**	**$ 184,940**	**$ (111)**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	64,000	64,000	-	67,500	3,500
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 249,051**	**$ 249,051**	**$ -**	**$ 252,440**	**$ 3,389**
Expenses					
Personnel Expenses					
Salaries	$ 18,399	$ 18,399	$ -	$ 18,600	$ 201
Payroll Taxes	1,350	1,350	-	1,513	163
Benefits	4,893	4,893	-	6,805	1,912
Retirement Costs	2,320	2,320	-	2,379	58
Total Personnel Expenses	**$ 26,963**	**$ 26,963**	**$ -**	**$ 29,297**	**$ 2,334**
Meeting Expenses					
Meetings	$ 188,300	$ 188,300	$ -	$ 189,000	$ 700
Travel	15,000	15,000	-	15,000	-
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 203,300**	**$ 203,300**	**$ -**	**$ 204,000**	**$ 700**
Operating Expenses					
Consultants & Contracts	$ -	$ -	$ -	$ -	$ -
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Direct Expenses	**$ 230,263**	**$ 230,263**	**$ -**	**$ 233,297**	**$ 3,034**
Indirect Expenses	**$ 19,460**	**$ 19,460**	**$ -**	**$ 19,475**	**$ 14**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 249,723**	**$ 249,723**	**$ -**	**$ 252,772**	**$ 3,048**
Change in Assets	**$ (672)**	**$ (672)**	**$ -**	**$ (332)**	**$ 341**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(672)	(672)	-	(332)	341
Inc(Dec) in Fixed Assets (C)	**(672)**	**(672)**	**-**	**(332)**	**341**
TOTAL BUDGET (=B+C)	249,051	249,051	-	252,440	3,389
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)	2018 Budget	2019 Budget	Increase (Decrease)
Total FTEs	5.00	5.00	0.00
Direct Expenses	$1,373,791	$1,409,379	$35,589
Indirect Expenses	$973,021	$973,726	$705
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($33,611)	($16,577)	$17,033
Total Funding Requirement	$2,313,202	$2,366,528	$53,326

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*." Related contributing activities to this Goal 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."

Event Analysis Program Description

NERC and the industry analyzes events, identifies the lessons to be learned, and conducts 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-004-3, "Event Reporting," (EOP-004-4, Effective April 1, 2019) 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 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 detailed and in-depth analysis; only concise and succinct reviews are desired for more minor events. It also 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 the lesser events on the system and learning from these events, larger events can be avoided or 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 analysis, lessons learned which may benefit the industry and the Standards sufficiency review and cause coding 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.

2019 Key Assumptions

- The monitoring of Lessons Learned will continue to be a major focus of NERC in 2019, including an added aspect of reporting in the voluntary Event Analysis Program to collect detailed information on station equipment failure, and response to a recommendation of

the AC Substation Equipment Task Force, to solicit and collect this data , for applicable qualifying events 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, and utilization and added aspects 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 improved information collection related to such events and associated analysis.

- Critical infrastructure protection will fully integrate the requirements of version 5 of the Cyber Standards in 2019.
- NERC will post updates to the Critical Infrastructure Protection Standards to address the three FERC Directives and the four industry concerns that were not satisfactorily responded to by the version 5 Transition Advisory Group.
- Resource allocation to this program area will support: expanded Events Analysis activities; coordination with NERC's evolving E-ISAC capabilities; and cybersecurity outreach efforts.

Situation Awareness 2019 Goals and Deliverables

- NPCC will provide the Regional perspective and support through NPCC Event Analysis staff participation on selective NERC Planning and Operating Committees and key related NERC Subcommittees, Task Forces and Working Groups, including the Event Analysis Subcommittee, the ERO – Event Analysis/Situational Awareness Group; and the Event Analysis Management System.
- 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 established 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 IV wide-area exercise.
- Utilize the NPCC's "what if" methodology to examine select events, with potential for greater impact under a different set of system conditions, to evaluate whether the event's proximity to becoming a more significant event would suggest that an appropriate level of analysis, with due weight to risk and impact, be conducted.
- 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 initiative, a near real-time operating display for the United States portion of the Reliability Coordinators footprints of North America. Transmission voltage levels of 230 kV and above are displayed, and the tool provides the ability to "drill down" to detailed bus information, including generation outputs and bus voltages.

Critical Infrastructure Objectives

NPCC's critical infrastructure 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 2019 critical infrastructure goals and objectives, supporting 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 "In collaboration with the Critical Infrastructure Protection Committee and industry stakeholders, develop a risk process to address the potential impact of cyber and physical security threats and vulnerabilities."

Critical Infrastructure 2019 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.
- 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. The Task Force will conduct a thorough review, provide comments as necessary and act on posted materials as directed.
- Support the NERC CIPC Grid Exercise Working Group in GridEx V planning and simulation. Participate in the development of lessons learned from GridEx IV.
- 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 2019 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 16% of its resources on this activity.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in the Situation Awareness and Infrastructure Security program area in 2019.

Situation Awareness and Infrastructure Security Program

Funding sources and related expenses for the situation awareness and infrastructure security 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
2018 Budget & Projection, and 2019 Budget
Situation Awareness and Infrastructure Security

	2018 Budget	2018 Projection	Variance 2018 Projection v 2018 Budget Over(Under)	2019 Budget	Variance 2019 Budget v 2018 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 2,300,208	$ 2,300,208	$ -	$ 2,366,528	$ 66,320
Penalty Sanctions	12,994	12,994	-	-	(12,994)
Total ERO Funding	**$ 2,313,202**	**$ 2,313,202**	**$ -**	**$ 2,366,528**	**$ 53,326**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 2,313,202**	**$ 2,313,202**	**$ -**	**$ 2,366,528**	**$ 53,326**
Expenses					
Personnel Expenses					
Salaries	$ 825,560	$ 825,560	$ -	$ 832,408	$ 6,848
Payroll Taxes	53,677	53,677	-	57,432	3,755
Benefits	189,417	189,417	-	201,196	11,780
Retirement Costs	87,637	87,637	-	89,043	1,406
Total Personnel Expenses	**$ 1,156,291**	**$ 1,156,291**	**$ -**	**$ 1,180,079**	**$ 23,789**
Meeting Expenses					
Meetings	$ 10,000	$ 10,000	$ -	$ 10,000	$ -
Travel	87,500	87,500	-	89,300	1,800
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 97,500**	**$ 97,500**	**$ -**	**$ 99,300**	**$ 1,800**
Operating Expenses					
Consultants & Contracts	$ 120,000	$ 120,000	$ -	$ 130,000	$ 10,000
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 120,000**	**$ 120,000**	**$ -**	**$ 130,000**	**$ 10,000**
Total Direct Expenses	**$ 1,373,791**	**$ 1,373,791**	**$ -**	**$ 1,409,379**	**$ 35,589**
Indirect Expenses	**$ 973,021**	**$ 973,021**	**$ -**	**$ 973,726**	**$ 705**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 2,346,812**	**$ 2,346,812**	**$ -**	**$ 2,383,105**	**$ 36,293**
Change in Assets	**$ (33,611)**	**$ (33,611)**	**$ -**	**$ (16,577)**	**$ 17,033**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(33,611)	(33,611)	-	(16,577)	17,033
Inc(Dec) in Fixed Assets (C)	**(33,611)**	**(33,611)**	**-**	**(16,577)**	**17,033**
TOTAL BUDGET (=B+C)	2,313,202	2,313,202	-	2,366,528	53,326
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ 0**	**$ 0**	**$ -**	**$ (0)**	**$ (0)**

Administrative Services

Administrative Services Program Resources (in whole dollars)	Direct Expenses and Fixed Assets			FTEs		
	2018 Budget	2019 Budget	Increase (Decrease)	2018 Budget	2019 Budget	Increase (Decrease)
Technical Committees and Members Forum	$70,680	$74,483	$3,803	0.50	0.50	0.00
General and Administrative	$3,338,132	$3,391,903	$53,771	2.50	2.50	0.00
Legal and Regulatory	$592,049	$612,934	$20,886	1.00	1.00	0.00
Information Technology	$1,119,490	$1,253,781	$134,291	2.00	2.00	0.00
Human Resources	$181,145	$156,946	($24,199)	1.00	1.00	0.00
Finance and Accounting	$537,236	$642,798	$105,562	1.00	2.00	1.00
Total Administrative Services[1]	$5,838,732	$6,132,845	$294,113	8.00	9.00	1.00

[1] NPCC's 2019 Administrative Services budget (expenses plus fixed asset activity) is $6,132,845, of which $416,755 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 2019 statutory budget are $5,815,090 which is an increase of $198,812 from the 2018 budget of $5,616,279.

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 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
2018 Budget & Projection, and 2019 Budget
ADMINISTRATIVE SERVICES

		2018 Budget	2018 Projection	Variance 2018 Projection v 2018 Budget Over(Under)	2019 Budget	Variance 2019 Budget v 2018 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ (66,581)	$ (66,581)	$ -	$ (100,061)	$ (33,480)
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ (66,581)**	**$ (66,581)**	**$ -**	**$ (100,061)**	**$ (33,480)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ (66,581)**	**$ (66,581)**	**$ -**	**$ (100,061)**	**$ (33,480)**
Expenses						
Personnel Expenses						
	Salaries	$ 2,063,139	$ 2,043,839	$ (19,300)	$ 2,147,254	$ 84,115
	Payroll Taxes	97,378	95,378	(2,000)	107,437	10,059
	Benefits	438,408	437,408	(1,000)	493,115	54,707
	Retirement Costs	295,596	288,996	(6,600)	296,142	546
Total Personnel Expenses		**$ 2,894,522**	**$ 2,865,622**	**$ (28,900)**	**$ 3,043,948**	**$ 149,426**
Meeting Expenses						
	Meetings	$ 116,750	$ 116,750	$ -	$ 126,750	$ 10,000
	Travel	138,000	138,000	-	135,100	(2,900)
	Conference Calls	37,000	37,000	-	36,000	(1,000)
Total Meeting Expenses		**$ 291,750**	**$ 291,750**	**$ -**	**$ 297,850**	**$ 6,100**
Operating Expenses						
	Consultants & Contracts	$ 92,000	$ 92,000	$ -	$ 95,000	$ 3,000
	Office Rent	810,700	810,700	-	820,700	10,000
	Office Costs	664,760	664,760	-	676,347	11,587
	Professional Services	960,000	960,000	-	978,000	18,000
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	50,000	50,000	-	51,000	1,000
	Depreciation	269,000	269,000	-	269,000	-
Total Operating Expenses		**$ 2,846,460**	**$ 2,846,460**	**$ -**	**$ 2,890,047**	**$ 43,587**
	Total Direct Expenses	**$ 6,032,732**	**$ 6,003,832**	**$ (28,900)**	**$ 6,231,845**	**$ 199,113**
Indirect Expenses		**$ (6,032,732)**	**$ (6,032,732)**	**$ -**	**$ (6,231,845)**	**$ (199,113)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 0**	**$ (28,900)**	**$ (28,900)**	**$ -**	**$ (0)**
Change in Assets		**$ (66,581)**	**$ (37,681)**	**$ 28,900**	**$ (100,061)**	**$ (33,480)**
Fixed Assets						
	Depreciation	(269,000)	(269,000)	$ -	(269,000)	$ -
	Computer & Software CapEx	75,000	75,000	-	170,000	95,000
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	194,000	194,000	-	99,000	(95,000)
Inc(Dec) in Fixed Assets (C)		**-**	**-**	**-**	**-**	**-**
TOTAL BUDGET (=B+C)		0	(28,900)	(28,900)	-	(0)
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (66,581)**	**$ (37,681)**	**$ 28,900**	**$ (100,061)**	**$ (33,480)**

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.

2019 Key Assumptions

- NPCC's standing committee and subgroup structure for effective stakeholder involvement will continue in 2019.
- 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 2019.
- 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 2019 Goals and Deliverables

- The 2019 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 2019 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

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2019.

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

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2019.

Office Rent

- Projected increase in real estate taxes.

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 anticipates no need to hire additional personnel in this program area in 2019.

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 2019 Business Plan and Budget assumes agreed-upon ERO Enterprise applications will be available and includes only NPCC costs for Region specific support needs.

2019 Key Assumptions

- Continue to maintain the compliance portal through collaboration with other Regional Entities and NERC (CUG).
- 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.

2019 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:

- Expand the utilization of the document management system throughout the company.
- Create an information security program and environment aimed at reducing breach of security risks.
- Determine longer-term software and systems needs and hardware acquisitions.
- Develop and implement information security standards and procedures.

- Ensure all information systems are functional and secure, and that all applications running on those systems meet business requirements for performance, availability, and security.
- Plan and implement organization-wide information systems, services, and network facilities, including local area networks, wide-area networks, and peripheral systems.
- Provide outreach and education to NPCC members in IT best practices.
- Continually improve Disaster Recovery and Business Continuity policies and practices to ensure continuity and reliability of IT and business related services.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2019.

Fixed Assets

- Capital expenditures planned for 2019 include the continuing implementation and enhancement of the document management system.

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

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2019.

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.

2019 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

Personnel

- One additional FTE will replace a continuous series of interns retained over several years in order to meet the ongoing resource needs in this program area and enable long-term sustained knowledge transfer.

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 BAAs within NPCC as the designees for the load-serving-entities 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 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 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 BAAs total average percentage of enforcement activities. The portion allocated to the U.S. BAAs in NPCC is calculated using the enforcement activity based methodology, and this amount is then re-allocated between the New York and New England BAAs based on their relative NEL.

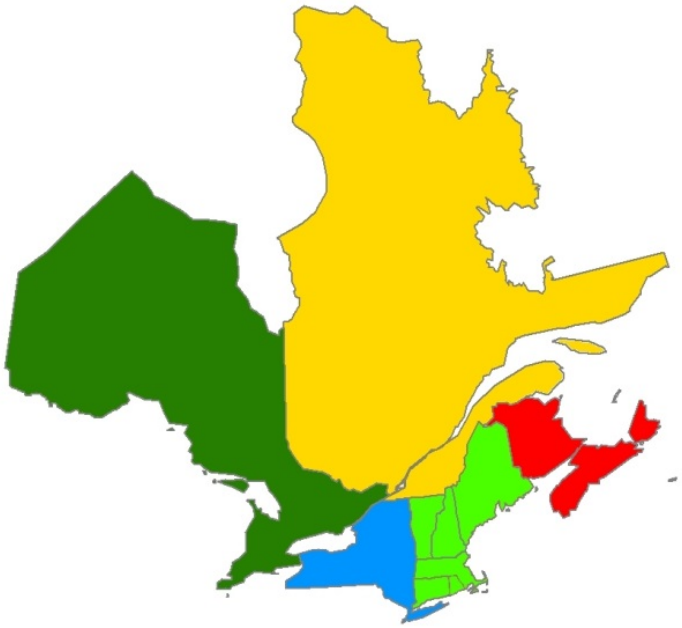
Any penalty monies received from NPCC registered entities within the U.S. by June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs, and then added to the total compliance 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
2019 Business Plan and Budget



Section B – Supplemental Financial Information

Reserve Balance

Table B-1 Reserve Balance

Working Capital and Operating Reserve Analysis 2018-2019 REGIONAL ENTITY DIVISION	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Total Reserve, December 31, 2017	5,017,751	2,818,887	1,258,864	940,000
Plus: 2018 ERO Funding (from LSEs or designees)	14,341,787	14,341,787		
Plus: 2018 Other funding sources	139,000	139,000		
Less: 2018 Projected expenses & capital expenditures	(15,044,967)	(15,044,967)		
Projected Total Reserve, December 31, 2018	**4,453,571**	**2,254,707**	**1,258,864**	**940,000**
Desired Total Reserve, December 31, 2019	**3,720,638**	1,463,777 [1]	1,316,860 [2]	940,000
Less: Projected Total Reserve, December 31, 2018	(4,453,571)	(2,254,707)	(1,258,864)	(940,000)
Increase(decrease) in assessments to achieve desired Total Reserve	**(732,933)**	(790,930)	57,997	0

2019 Expenses and Capital Expenditures	15,802,955
Less: Penalty Sanctions [4]	0
Less: Other Funding Sources	(67,500)
Less: Release of Business Continuity Reserve Funds [3]	0
Adjustment to Working Capital to achieve desired Total Reserve balance [2]	57,997
Adjustment to Operating Reserve to achieve desired Total Reserve balance [1]	(790,930)
2019 Assessment	**15,002,522**

[1] Operating Reserve within a range from 8.33% to 25.00% of Budget. $1,463,777 represents 9.26% of the 2019 budget of $15,802,955
[2] Working Capital equal to 8.33% of Budget. $1,316,860 represents 8.33% of the 2019 budget of $15,802,955
[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, 2017 to June 30, 2018.

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 identified as restricted cash and drawn upon as subsequently brought before the Board of Directors in association with President & CEO succession related activities associated with a planned or 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 2019 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, 2018 are to be used to offset assessments in the 2019 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 will be used to offset U.S. load serving entity designee assessments in the 2019 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, 2018	Date Received	Amount Received
		$ -
Total Penalties Received		**$ -**

Table B-3 Supplemental Funding

Outside Funding Breakdown By Program (excluding ERO Assessments & Penalty Sanctions)	Budget 2018	Projection 2018	Budget 2019	Variance 2019 Budget v 2018 Budget
Reliability Standards				
Total	$ -	$ -	$ -	$ -
Compliance Monitoring, Enforcement & Org. Registration				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Reliability Assessment and Performance Analysis				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Training and Education				
Workshops	$ 64,000	$ 64,000	$ 67,500	$ 3,500
Total	$ 64,000	$ 64,000	$ 67,500	$ 3,500
Situation Awareness and Infrastructure Security				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Technical Committees and Member Forums				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Administrative Services Programs				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Total Outside Funding	$ 64,000	$ 64,000	$ 67,500	$ 3,500

Explanation of Significant Variances –2019 Budget versus 2018 Budget

- NPCC assumed no interest income because of continuing low market interest rates.

Table B-4 Personnel Expenses

Personnel Expenses	Budget 2018	Projection 2018	Budget 2019	Variance 2019 Budget v 2018 Budget	Variance %
Salaries					
Salary	$ 7,057,483	$ 7,057,483	$ 7,298,280	$ 240,797	3.4%
Employment Agency Fees	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Temporary Office Services	$ 40,116	$ 40,116	$ 24,000	$ (16,116)	-40.2%
Total Salaries	$ 7,107,599	$ 7,107,599	$ 7,332,280	$ 224,681	3.2%
Total Payroll Taxes	$ 411,440	$ 411,440	$ 449,994	$ 38,553	9.4%
Benefits					
Education Reimbursement	$ 30,000	$ 30,000	$ 32,000	$ 2,000	6.7%
Training and Seminars	$ 44,232	$ 44,232	$ 58,290	$ 14,058	31.8%
Medical Insurance	$ 811,369	$ 811,369	$ 901,783	$ 90,414	11.1%
Life-LTD-STD Insurance	$ 90,465	$ 90,465	$ 94,804	$ 4,339	4.8%
Worker's Compensation	$ 15,000	$ 15,000	$ 20,000	$ 5,000	33.3%
Vacation	$ 485,312	$ 485,312	$ 506,201	$ 20,889	4.3%
Relocation	$ -	$ -	$ -	$ -	-
Total Benefits	$ 1,476,378	$ 1,476,378	$ 1,613,078	$ 136,700	9.3%
Retirement					
Pension Contribution	$ 38,000	$ 38,000	$ -	$ (38,000)	-100.0%
Employee Savings Plan	$ 714,353	$ 714,353	$ 741,511	$ 27,157	3.8%
Savings Admin	$ 35,000	$ 35,000	$ 36,000	$ 1,000	2.9%
Deferred Compensation	$ 38,000	$ 38,000	$ 76,000	$ 38,000	100.0%
Total Retirement	$ 825,353	$ 825,353	$ 853,511	$ 28,157	3.4%
Total Personnel Costs	**$ 9,820,770**	**$ 9,820,770**	**$ 10,248,862**	**$ 428,092**	**4.4%**
FTEs	36.86	36.86	38.86	2.00	5.4%
Cost per FTE					
Salaries	$ 192,827	$ 192,827	$ 188,685	$ (4,142)	-2.1%
Payroll Taxes	$ 11,162	$ 11,162	$ 11,580	$ 418	3.7%
Benefits	$ 40,054	$ 40,054	$ 41,510	$ 1,456	3.6%
Retirement	$ 22,392	$ 22,392	$ 21,964	$ (428)	-1.9%
Total Cost per FTE	**$ 266,434**	**$ 266,434**	**$ 263,738**	**$ (2,696)**	**-1.0%**

Explanation of Significant Variances –2019 Budget versus 2018 Budget

- Temporary office services were decreased as the result of one additional FTE in Accounting and Finance.
- Education reimbursement cost is based on employees expressing interest in or actively pursuing advanced degrees.
- Pension Contribution decrease is offset by Deferred Compensation increase of the same amount due to the reclassification of 457(b) expenses.
- Decrease in cost per FTE is related to the retirement of a number of seasoned professionals resulting in vacancies which were filled through a combination of in-house promotions, resource re-allocations and the retention of less seasoned successors.

Table B-5 Meeting Expense

Meeting Expenses	Budget 2018	Projection 2018	Budget 2019	Variance 2019 Budget v 2018 Budget	Variance %
Meetings	$ 353,050	$ 353,050	$ 370,750	$ 17,700	5.0%
Travel	$ 834,500	$ 834,500	$ 845,900	$ 11,400	1.4%
Conference Calls	$ 37,000	$ 37,000	$ 36,000	$ (1,000)	-2.7%
Total Meeting Expenses	**$ 1,224,550**	**$ 1,224,550**	**$ 1,252,650**	**$ 28,100**	**2.3%**

Explanation of Significant Variances –2019 Budget versus 2018 Budget

- Continued efforts to limit the number of attendees to offsite meetings and hold more meetings on-site and via webinar.
- Spring and Fall Standards and Compliance Workshops compressed from three days to two days.

Table B-6 Consultants and Contracts

Consultants	Budget 2018	Projection 2018	Budget 2019	Variance 2019 Budget v 2018 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	$ -	$ -	$ -	$ -	-
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ -	$ -	$ -	$ -	-
Consultants Total	**$ -**	**$ -**	**$ -**	**$ -**	**-**

Contracts	Budget 2018	Projection 2018	Budget 2019	Variance 2019 Budget v 2018 Budget	Variance %
Reliability Standards	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Compliance Enforcement and Organization Registration and Certification	$ 1,254,000	$ 1,254,000	$ 1,357,150	$ 103,150	8.2%
Reliability Assessment and Performance Analysis	$ 401,640	$ 401,640	$ 430,000	$ 28,360	7.1%
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ 120,000	$ 120,000	$ 130,000	$ 10,000	8.3%
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ 85,000	$ 85,000	$ 88,000	$ 3,000	3.5%
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ 7,000	$ 7,000	$ 7,000	$ -	0.0%
Contracts Total	**$ 1,877,640**	**$ 1,877,640**	**$ 2,022,150**	**$ 144,510**	**7.7%**
Total Consultants and Contracts	**$ 1,877,640**	**$ 1,877,640**	**$ 2,022,150**	**$ 144,510**	**7.7%**

Explanation of Significant Variances –2019 Budget versus 2018 Budget

- 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 2018	Projection 2018	Budget 2019	Variance 2019 Budget v 2018 Budget	Variance %
Office Rent	$ 650,000	$ 650,000	$ 650,000	$ -	0.0%
Utilities	$ 43,000	$ 43,000	$ 45,000	$ 2,000	4.7%
Maintenance	$ 35,000	$ 35,000	$ 37,000	$ 2,000	5.7%
Security	$ 2,700	$ 2,700	$ 2,700	$ -	0.0%
Real Estate Taxes	$ 80,000	$ 80,000	$ 86,000	$ 6,000	7.5%
Total Office Rent	**$ 810,700**	**$ 810,700**	**$ 820,700**	**$ 10,000**	**1.2%**

Explanation of Significant Variances –2019 Budget versus 2018 Budget

- Projected increase in real estate taxes.

Table B-8 Office Costs

Office Costs	Budget 2018	Projection 2018	Budget 2019	Variance 2019 Budget v 2018 Budget	Variance %
Telephone	$ 111,660	$ 111,660	$ 88,720	$ (22,940)	-20.5%
Internet Expense	$ 95,000	$ 95,000	$ 82,740	$ (12,260)	-12.9%
Office Supplies	$ 33,000	$ 33,000	$ 33,000	$ -	0.0%
Computer Supplies and Maintenance	$ 350,600	$ 350,600	$ 397,387	$ 46,787	13.3%
Subscriptions & Publications	$ 13,500	$ 13,500	$ 13,500	$ -	0.0%
Dues	$ 3,400	$ 3,400	$ 3,400	$ -	0.0%
Postage	$ 1,200	$ 1,200	$ 1,200	$ -	0.0%
Express Shipping	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Copying	$ 26,400	$ 26,400	$ 26,400	$ -	0.0%
Reports	$ 8,000	$ 8,000	$ 8,000	$ -	0.0%
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	**$ 664,760**	**$ 664,760**	**$ 676,347**	**$ 11,587**	**1.7%**

Explanation of Significant Variances –2019 Budget versus 2018 Budget

- Total Office costs are expected to remain relatively flat.

Table B-9 Professional Services

Professional Services	Budget 2018	Projection 2018	Budget 2019	Variance 2019 Budget v 2018 Budget	Variance %
BOT Fee	$ 340,000	$ 340,000	$ 346,000	$ 6,000	1.8%
BOT Search Fee	$ -	$ -	$ -	$ -	-
Legal - Reorganization	$ -	$ -	$ -	$ -	-
Accounting & Auditing Fees	$ 300,000	$ 300,000	$ 300,000	$ -	0.0%
Legal Fees - Other	$ 250,000	$ 250,000	$ 262,000	$ 12,000	4.8%
Insurance - Commercial	$ 70,000	$ 70,000	$ 70,000	$ -	0.0%
Total Services	**$ 960,000**	**$ 960,000**	**$ 978,000**	**$ 18,000**	**1.9%**

Table B-10 Miscellaneous

Miscellaneous Expense	Budget 2018	Projection 2018	Budget 2019	Variance 2019 Budget v 2018 Budget	Variance %
Miscellaneous Expense	$ 50,000	$ 50,000	$ 51,000	$ 1,000	2.0%
Total Miscellaneous Expense	**$ 50,000**	**$ 50,000**	**$ 51,000**	**$ 1,000**	**2.0%**

Table B-11 Other Non-Operating Expenses

Other Non-Operating Expenses	Budget 2018	Projection 2018	Budget 2019	Variance 2019 Budget v 2018 Budget	Variance %
Interest Expense	$ -	$ -	$ -	$ -	-
Office Relocation	$ -	$ -	$ -	$ -	-
Total Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**-**

Table B-12 Fixed Assets

Fixed Assets	Budget 2018	Projection 2018	Budget 2019	Variance 2019 Budget v 2018 Budget	Variance %
Depreciation	$ (269,000)	$ (269,000)	$ (269,000)	$ -	0.0%
Equipment CapEx	$ -	$ -	$ -	$ -	-
Computer & Software CapEx	$ 115,000	$ 115,000	$ 170,000	$ 55,000	47.8%
Furniture & Fixtures CapEx	$ -	$ -	$ -	$ -	-
Leasehold Improvements	$ -	$ -	$ -	$ -	-
Allocation of Fixed Assets	$ -	$ -	$ -	$ -	-
Total Increase (Decrease) in Fixed Assets	**$ (154,000)**	**$ (154,000)**	**$ (99,000)**	**$ 55,000**	**-35.7%**

Explanation of Significant Variances –2019 Budget versus 2018 Budget

- Capital expenditures planned for 2019 include the continuing implementation of the document management system.

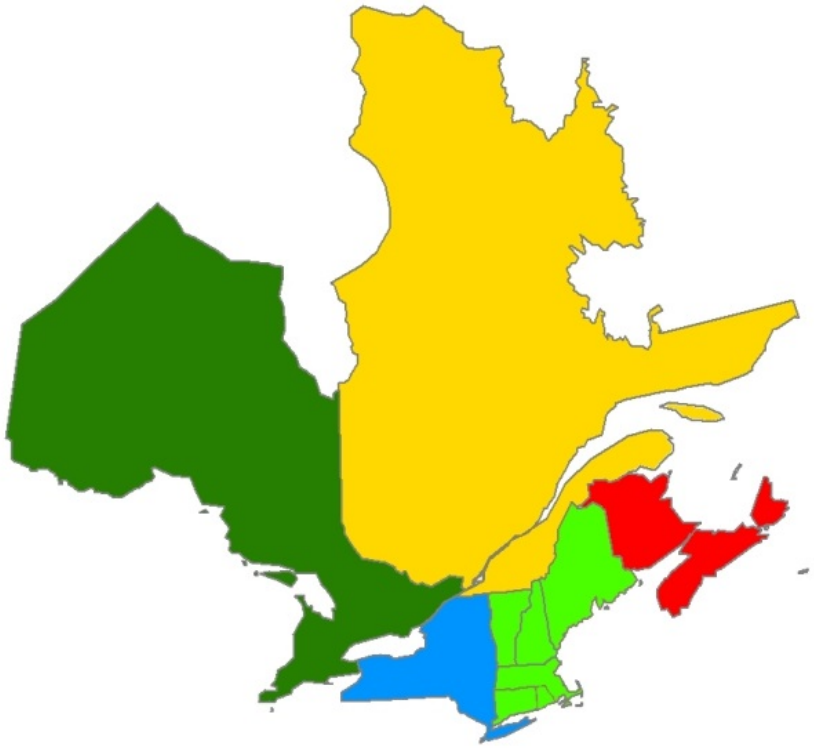
Table B-13 2020 and 2021 Projections

Table to be Inserted

Assumptions

Section C — Criteria Services Division Activities

2019 Business Plan and Budget



Section C – Criteria Services Division Activities

Criteria Services Division (in whole dollars)	2018 Budget	2019 Budget	Increase (Decrease)
Total FTEs	2.14	2.14	0.00
Total Direct Expenses	$666,530	$678,756	$12,226
Total Indirect Expenses	$416,453	$416,755	$302
Other Non-Operating Expenses	$0	$0	$0
Working Capital and Operating Reserves Requirement	($47,843)	($49,749)	($1,907)
Inc(Dec) in Fixed Assets	($16,000)	$14,000	$30,000
Funding Requirement	$1,019,141	$1,059,761	$40,620

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 2019 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 2019 Assumptions and Cost Impacts

The Criteria Services division activities are expected to remain stable or slightly increase throughout 2019 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.

2019 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.
- 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.
    - *A-10 - Classification of Bulk Power System Elements* - the TFCP will conclude its review of the A-10 methodology in 2019.
    - 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 2019, 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.

NPCC Operations and Planning Directories

The following Directories are envisioned to remain active for 2019.

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 in 2015, 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 2018.

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 with Regionally specific, more stringent NPCC Criteria. The criteria are unique to the NPCC BPS and are not duplicative of the NERC Reliability Standards. The criteria evolved over many years and were determined to be technically necessary, to maintain the reliability of the NPCC BPS and prevent cascading outages. In addition, the physical characteristics and topology of the transmission system within the Region require that these specific, more stringent criteria be developed and that compliance be monitored for these criteria.

NPCC Membership, in conjunction with the Criteria Services Division of the NPCC Staff, developed the CCEP. The NPCC Compliance Committee administers the CCEP. The NPCC Compliance Committee is a stakeholder body consisting of NPCC Members, structured with seven sectors. They are Transmission Owners; Reliability Coordinators; Transmission Dependent Utilities, Distribution Providers and Load-Serving Entities; Generator Owners; Marketers, Brokers and Aggregators; Regulators; Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities.

Non-compliance to NPCC Criteria are not subject to monetary sanctions, whereas violations of NERC Reliability Standards are subject to monetary sanctions. Currently non- compliance of NPCC Criteria result in escalating notification to appropriate entities based on the severity of the non-compliance.

The following two guiding documents describe the implementation of the CCEP:

- The CCEP program is described in document CCEP-1, *NPCC Criteria Compliance and Enforcement Program (CCEP) Process Document*

- The implementation plan is described in document CCEP-2, *Implementation Plan for 2011 NPCC Criteria Compliance and Enforcement Program*

The NPCC Compliance Committee reviews these documents on a regular basis. Should the NPCC Compliance Committee revise the CCEP-1 document, it will prepare an approved final version that is distributed to the NPCC Membership for vote. As the CCEP is only applicable to the NPCC Criteria, which is the responsibility of the Full Members of NPCC, the Full Members of NPCC must vote on revisions to the document

The CCEP-1 document also:

1) Provides a comprehensive CCEP Process Diagram showing the process of evaluating and approving Criteria Certification submittals, and additional processes and responsibilities in the event that non-compliances, disputes and sanctions arise;

2) Describes the roles and responsibilities of Reporting Members, the NPCC Compliance Committee, the NPCC Reliability Coordinating Committee and the Enforcement Panel in the compliance review and enforcement process;

3) Describes Levels of Non-Compliance, associated non-monetary Sanctions, Lateness Policy and the Arbitration/Dispute Resolution process;

4) Addresses Mitigation Plans for any violations under the enforcement process; and

5) Lists the Certification Forms to be submitted for review.

Annually, the CCEP Working Group, under the NPCC Compliance Committee, develops the CCEP implementation plan and also reviews the compliance submittals and prepares a report for the entire NPCC Compliance Committee. The NPCC Compliance Committee has final approval of compliance assessments related to CCEP. Once the Compliance Committee approves the final report, it is presented to the NPCC Reliability Coordinating Committee for its 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 – 2019 Budget versus 2018 Budget

- None.

2018 Budget and Projection and 2019 Budget Comparisons

Statement of Activities and Capital Expenditures
2018 Budget & Projection, and 2019 Budget
CRITERIA SERVICES DIVISION

		2018 Budget	2018 Projection	Variance 2018 Projection v 2018 Budget Over(Under)	2019 Budget	Variance 2019 Budget v 2018 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ -	$ -	$ -	$ -	$ -
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Membership Dues	1,019,141	1,019,141	-	1,059,761	40,620
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 1,019,141**	**$ 1,019,141**	**$ -**	**$ 1,059,761**	**$ 40,620**
Expenses						
Personnel Expenses						
	Salaries	$ 404,848	$ 404,848	$ -	$ 371,938	$ (32,909)
	Payroll Taxes	23,413	23,413	-	23,696	283
	Benefits	74,991	74,991	-	102,779	27,788
	Retirement Costs	43,272	43,272	-	43,182	(90)
Total Personnel Expenses		**$ 546,523**	**$ 546,523**	**$ -**	**$ 541,596**	**$ (4,927)**
Meeting Expenses						
	Meetings	$ 5,000	$ 5,000	$ -	$ 5,000	$ -
	Travel	55,647	55,647	-	56,800	1,153
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 60,647**	**$ 60,647**	**$ -**	**$ 61,800**	**$ 1,153**
Operating Expenses						
	Consultants & Contracts	$ 40,360	$ 40,360	$ -	$ 55,360	$ 15,000
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	3,000	3,000	-	4,000	1,000
	Depreciation	16,000	16,000	-	16,000	-
Total Operating Expenses		**$ 59,360**	**$ 59,360**	**$ -**	**$ 75,360**	**$ 16,000**
	Total Direct Expenses	**$ 666,530**	**$ 666,530**	**$ -**	**$ 678,756**	**$ 12,226**
Indirect Expenses		**$ 416,453**	**$ 416,453**	**$ -**	**$ 416,755**	**$ 302**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,082,983**	**$ 1,082,983**	**$ -**	**$ 1,095,510**	**$ 12,527**
Change in Assets		**$ (63,843)**	**$ (63,843)**	**$ -**	**$ (35,749)**	**$ 28,093**
Fixed Assets						
	Depreciation	$ (16,000)	(16,000)	$ -	$ (16,000)	$ -
	Computer & Software CapEx	-	-	-	30,000	30,000
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	-	-	-	-	-
Inc(Dec) in Fixed Assets (C)		**(16,000)**	**(16,000)**	**-**	**14,000**	**30,000**
TOTAL BUDGET (=B+C)		1,066,983	1,066,983	-	1,109,510	42,527
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (47,843)**	**$ (47,843)**	**$ -**	**$ (49,749)**	**$ (1,907)**

Personnel Analysis

Total FTE's by Program Area	Budget 2018	Projection 2018	Direct FTEs 2019 Budget	Shared FTEs1 2019 Budget	Total FTEs 2019 Budget	Change from 2018 Budget
CRITERIA SERVICES DIVISION						
Operational Programs						
Reliability Standards	1.07	1.07	1.00	0.07	1.07	0.00
Compliance Enforcement and Organization Registration and Certification	0.00	0.00	0.00	0.00	0.00	0.00
Training and Education	0.00	0.00	0.00	0.00	0.00	0.00
Reliability Assessment and Performance Analysis	1.07	1.07	1.00	0.07	1.07	0.00
Situation Awareness and Infrastructure Security	0.00	0.00	0.00	0.00	0.00	0.00
Total FTEs Operational Programs	**2.14**	**2.14**	**2.00**	**0.14**	**2.14**	**0.00**
Administrative Programs						
Member Forums	0.00	0.00	0.00	0.00	0.00	0.00
General and Administrative	0.00	0.00	0.00	0.00	0.00	0.00
Information Technology	0.00	0.00	0.00	0.00	0.00	0.00
Legal and Regulatory	0.00	0.00	0.00	0.00	0.00	0.00
Human Resources	0.00	0.00	0.00	0.00	0.00	0.00
Accounting and Finance	0.00	0.00	0.00	0.00	0.00	0.00
Total FTEs Administrative Programs	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Total FTEs	**2.14**	**2.14**	**2.00**	**0.14**	**2.14**	**0.00**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

Reserve Analysis 2018 - 2019

Working Capital and Operating Reserve Analysis 2018-2019
CRITERIA SERVICES DIVISION

	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Total Reserve, December 31, 2017	534,786	386,031	88,755	60,000
2018 Non-Statutory Funding (from members)	1,019,141	1,019,141	0	
2018 Other funding sources	0	0	0	
Less: 2018 Projected expenses & fixed asset additions	(1,106,983)	(1,106,983)	0	
Projected Total Reserve, December 31, 2018	**446,943**	**298,188**	**88,755**	**60,000**
Desired Total Reserve, December 31, 2019	**397,194**	244,739 [1]	92,455 [2]	60,000
Less: Projected Total Reserve, December 31, 2018	(446,943)	(298,188)	(88,755)	(60,000)
Increase(decrease) in assessments to achieve desired Total Reserve	(49,749)	(53,450)	3,700	0

2019 Funding requirement for expenses and fixed asset additions	1,109,510
Less: Release of Business Continuity Reserve Funds [3]	0
Adjustment to Working Capital to achieve desired Total Reserve balance [2]	3,700
Adjustment to Operating Reserve to achieve desired Total Reserve balance [1]	(53,450)
2019 Funding and reserve requirement	1,059,761

[1] Total NPCC Operating Reserve must be within a range from 8.33% to 25.00% of Budget. $244,739 represents 22.06% of the 2019 CS budget of $1,109,510.

[2] Total NPCC Working Capital must equal 8.33% of Budget. $92,455 represents 8.33% of the 2019 CS budget of $1,109,510.

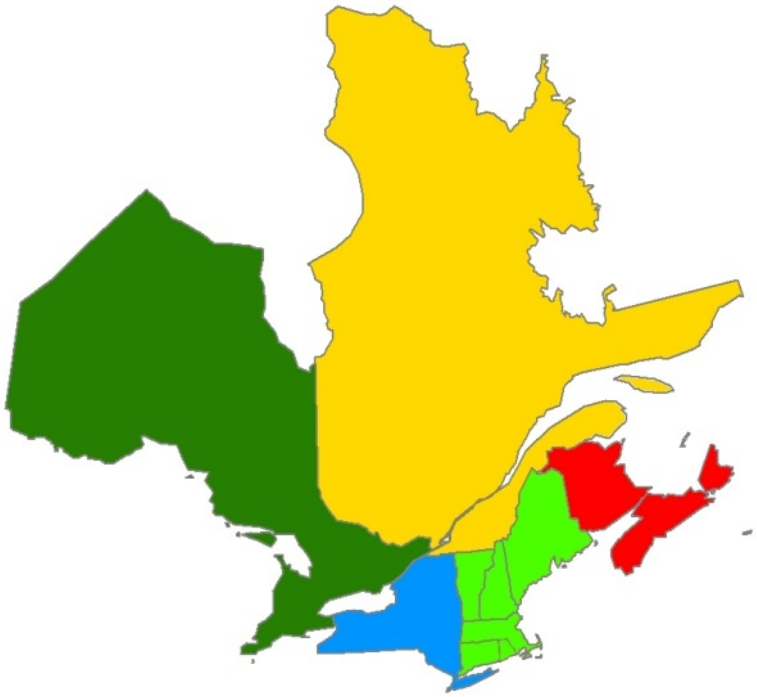
[3] Business Continuity Reserve (BCR) established in 2017 as approved by the NPCC Board of Directors to fund Succession Planning related expenses.

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 identified as restricted cash and drawn upon as subsequently brought before the Board of Directors in association with President & CEO succession related activities associated with a planned or 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

2019 Business Plan and Budget



Section D — Additional Financial Statements

Statement of Financial Position

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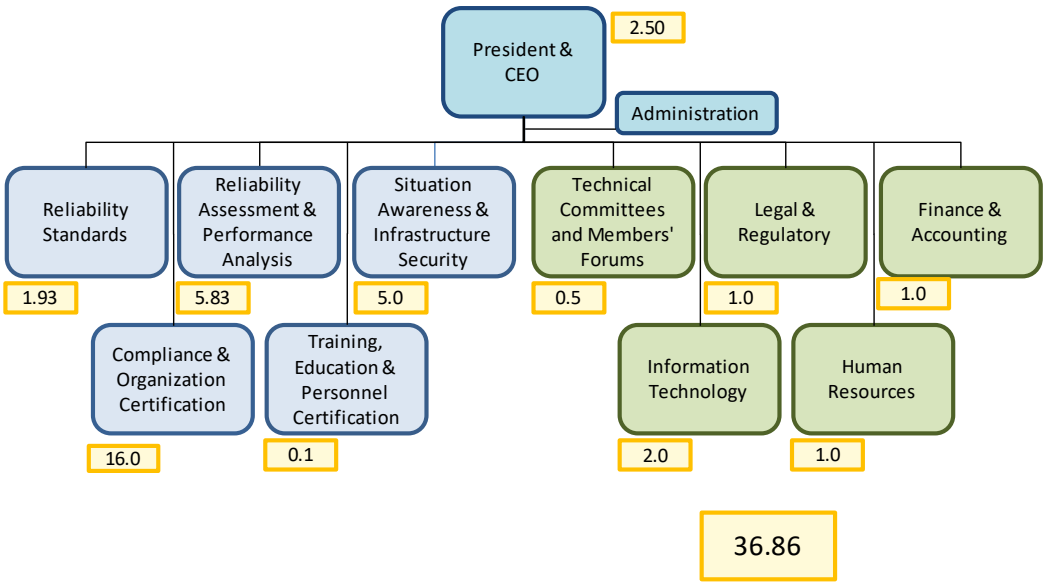
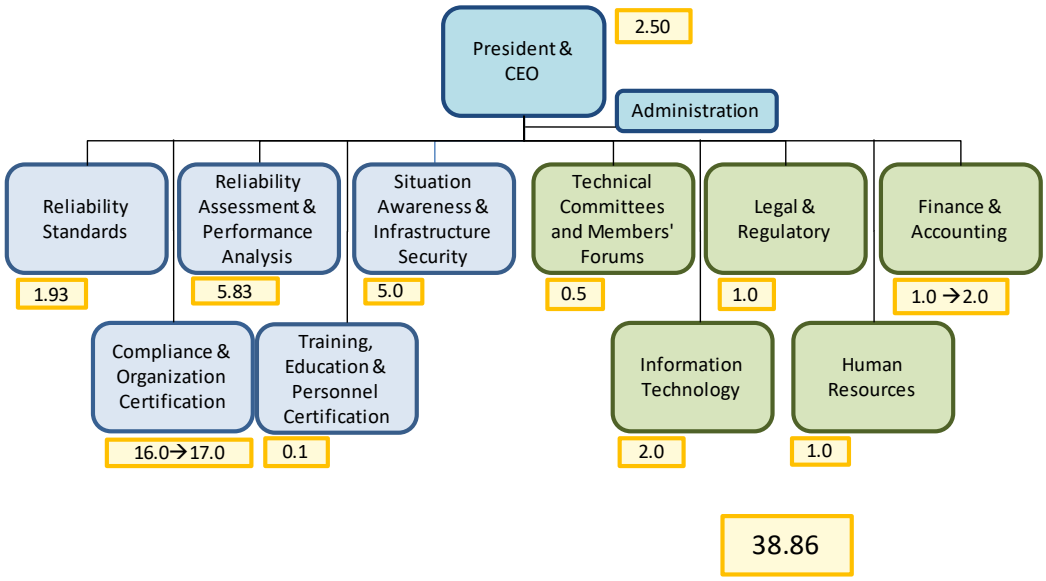
Appendix A Staff Allocations

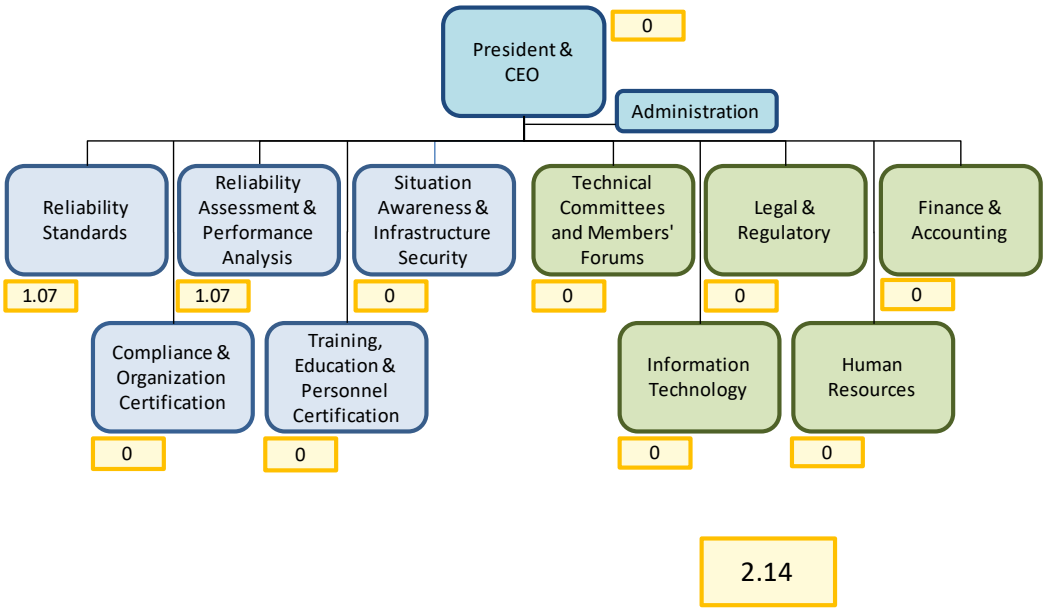
2018 Budget Staff Allocations - RE Division



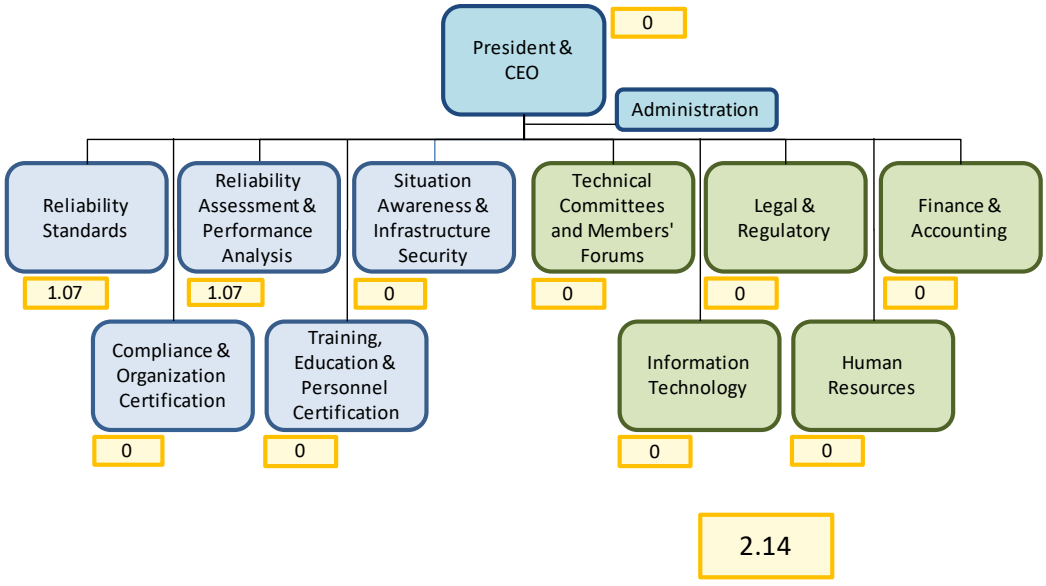
2019 Budget Staff Allocations - RE Division



2018 Budget Staff Allocations - CS Division



2019 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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