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

NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #17-3
August 23, 2017 10:00 a.m. – 5:00 p.m. EST
August 24, 2017 8:00 a.m. – 12:00 p.m. EST
Hydro One North Tower
483 Bay Street
Toronto, Canada
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada) **Guest Code: 28840965**

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

Introductions and Chair's Remarks

NPCC Antitrust Compliance Guidelines

Agenda Items:

1.0 Review of Agenda

2.0 RSC Meeting Minutes

3.0 Drafting Team Members and Executive Tracking Summary

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

4.0 Open Action Items

4.1 Open Action Items List

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin
5.2 CC Implementation Guidance Process
5.3 Standards Oversight and Technology Committee – Standards Efficiency Review
5.4 Reliability Guideline: ACE Diversity Interchange

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	8/23/17 Call-In
Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	8/11/17 (F)	8/11/17 (I)	Scott Barfield-McGinnis	1:00PM
Project 2016-04 Modifications to PRC-025-1	9/7/17 (F)	9/7/17 (I)	Scott Barfield-McGinnis	1:15PM
Project 2015-10 Single Points of Failure TPL-001	5/24/17 (I)		Latrice Harkness	1:30PM
Revisions to the NERC Standard Processes Manual	5/3/17 (F)	5/3/17 (I)	Chris Larson	1:45PM
Project 2017-01 Modifications to BAL-003-1.1	7/18/17 (F)		Darrel Richardson	2:00PM
Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards	7/24/17 (I)		Darrel Richardson	2:15PM
Project 2017-06 Modifications to BAL-002-2	7/20/17 (I)		Darrel Richardson	2:30PM
Project 2015-09 Establish and Communicate System Operating Limits	8/12/16 (I)		Darrel Richardson	2:45PM
Project 2017-05 NUC-001-3 Periodic Review			Mat Bunch	3:00PM
Project 2016-02 Modifications to CIP Standards CIP-012-1	9/11/17 (F)	9/11/17 (I)	Katherine Street Mat Bunch	3:15PM
2018-2020 Reliability Standards Development Plan	7/25/17 (F)		Sean Cavote	3:30PM
Project 2017-03 FAC-008-3 Periodic Review			Al McMeekin	3:45PM
2017 Periodic Review Standing Review Team - Standards Grading	8/2/17 (I)		Laura Anderson	4:00PM
Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards			Laura Anderson	4:15PM
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 RSC approval required for the posting of Automatic Underfrequency Load Shedding PRC-006-NPCC-02 draft redline

8.1.1..1 Provide target dates/schedule to RSC

8.1.1..2 Officially appoint Brian Robinson as the liaison between the RSC and PRC-006-NPCC-02 drafting team

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

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

9.1 Directories:

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

9.1.2 Directory#9 and #10 *Real and Reactive Capability Verification*

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

RAS Implementation/Transition

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

9.1.5 A-01 *Criteria for Review and Approval of Documents* – (RSC to consider incorporating document A-01 into the Directory review and Revision Manual).

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

9.1.7 Directory#4 System Protection Criteria – (status of Eversource 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 18th - Call	March 15th - Meeting	April 19th - Call
June 14th - Meeting	July 19th - Call	September 7th Meeting
October 18th - Call	December 6th - Meeting	

SC 2018 Schedule:

January 17th - Call	March 14th - Meeting	April 18th - Call
June 13th - Meeting	July 25th - Call	September 12th Meeting
October 17th - Call	December 5th - 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 21st - Call	March 14th – Meeting
March 29th – Call	May 22nd - Call	June 13th – Meeting
June 28th – Call	August 18th – Call	September 6th – Meeting
September 28th – Call	November 14th – Call	December 5th - Meeting

SCPS 2018 Schedule:

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

January 26th - Call	March 15th - Meeting	April 27th - Call
June 14th - Meeting	July 27th - Call	September 7th Meeting
October 12th - Call	December 6th - Meeting	

PMOS 2018 Schedule:

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 8-9 - Meeting	May 10-11 - Meeting	August 9-10 - Meeting
November 7-8 - Meeting		

BOT 2018 Schedule:

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 two new Lesson Learned issued since the last RSC meeting.

13.2 Alerts

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

There have been three new NERC Alerts released since the last RSC meeting.

13.3 Final NERC 2018 Business Plan and Budget

13.4 Proposed Additional Resolutions for Cyber Security – Supply Chain Risk Management

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

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

14.2 NPCC Board of Directors Meeting (BOD) 2017

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

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

14.3 NPCC Business Plan and Budget 2018

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2017 Meeting Dates

March 8th-9th, FRCC, Tampa FL
June 7th-8th, Saratoga NY
August 23rd-24th, Toronto
October 11th-12th, Lewiston NY
December 7th, Boston MA

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

January 20	February 3	February 17
March 24	April 7	April 21
May 5	May 19	June 16
June 30	July 14	July 28
August 11	September 8	September 22
September 29	October 27	November 10
November 24	December 22	

15.3 Tentative RSC 2018 Meeting Dates

February/March, NextEra/FRCC, Juno Beach/Tampa FL
June, Saratoga NY
August, Toronto
October, Lewiston NY
December, Toronto ON

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 #17-2
June 7, 2017 10:00 a.m. – 5:00 p.m. EST
June 8, 2017 8:00 a.m. – 12:00 p.m. EST
Hampton Inn & Suites Saratoga Springs Downtown Hotel
25 Lake Avenue
Saratoga Springs, New York
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada) **Guest Code: 28840965**

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated April 4, 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	Via Phone
5.	Mike Jones	National Grid	3	1 & 2	
6.	Quintin Lee	Eversource Energy	1	1 & 2	
7	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	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	
11.	David Ramkalawan	Ontario Power Generation, Inc.	4	1	Via Phone
12.	Chantel Mazza	Hydro-Québec TransÉnergie	2	1 & 2	
13.	Greg Campoli	New York Independent System Operator	2	1 & 2	

14.	Mark Capano	New York Independent System Operator	Guest	1	
15.	Payam Farahbakhsh	Hydro One Networks	1	1 & 2	
16.	Ben Wu	Orange & Rockland Utilities, Inc.	3	1 & 2	
17.	Salvatore Spagnolo	NYPA	4	1 & 2	
18.	Brian Robinson	Utility Services, Inc.	5	1 & 2	
19.	Sean Bodkin	Dominion Resources Services	4	1 & 2	Via Phone
20.	Glen Smith	Entergy Services, Inc	4	1 & 2	
21.	Michele Tondalo	The United Illuminating Company	1	1 & 2	Via Phone
22.	Jerry Ancona	New York State Department of Public Service	6	1	2nd Day Via Phone
23.	David Kiguel	Independent	Guest	1	Via Phone
24.	Kathleen Goodman	ISO-NE	2	1 & 2	
25.	Josh Eason	ISO-NE	2	1 & 2	
26.	John Helme	Utility Services, Inc.	Guest	1	Via Phone
27.	Mark Olson	NERC	Guest	1	Via Phone
28.	Sean Cavote	NERC	Guest	1	Via Phone
29.	Mat Bunch	NERC	Guest	1	Via Phone
30.	Latrice Harkness	NERC	Guest	1	Via Phone
31.	Chris Larson	NERC	Guest	1	Via Phone
32.	Darrel Richardson	NERC	Guest	1	Via Phone
33.	Scott Barfield-McGinnis	NERC	Guest	1	Via Phone

Introductions and Chair's Remarks

Guy Zito provided a brief introduction and gave a summary on the current NERC activities such as cost effectiveness and reduced funding to the US Geological Service' Magnetism Program which could potentially impact the industry and the requirements in TPL-007-1. Potential new SARs coming out for MOD-32.

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

Agenda Items:

1.0 Review of Agenda

Guy Zito proposed adding Agenda Item 6.4 TPL-007-02 Proposal to cut USGS Magnetism Program, Agenda Item 5.3 approval of new Vice-Chair of the RSC and Agenda Item 11.6 FERC Technical Conference on June 22nd. Guy Zito proposed the removal of Agenda Item 9.2 RAS Implementation/Transition because it is a duplicate.

2.0 RSC Meeting Minutes

Approval of Minutes—no additional revisions were made to the draft RSC meeting minutes of 3-8-17.
Herb Schrayshuen made a motion for approval.
Michael Jones seconded the motion.
Chantel Mazza, Dan Grinkevich and Greg Campoli abstained from the motion.
The meeting minutes were approved as read.

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams

The RSC members reviewed the roster and made modifications to list Project 2017-17.4 as inactive and revise the contact list for Project 2016-02.

3.2 Executive Tracking Summary

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

3.3 NERC Project Tracking Spreadsheet

The RSC members reviewed the Project Tracking Spreadsheet as a group.

4.0 Open Action Items

4.1 Open Action Items List

The RSC Members agreed to remove action item number 4.1 in regards to the feedback loop assigned to Guy Zito.
The members of RSC agreed to remove action item number 4.2 in regards to additional information on the status of GMD in Hydro Quebec which was assigned to Si Truc Phan.
Item 4.3 is completed.

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin

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

Ruida Shu provided a quick review on where to locate the NERC Weekly Standards Bulletin on NERC website.

5.2 RSC Approval for the Enhanced Periodic Review to NERC's Template

Approval of Review to Enhanced Periodic Review Template—no additional revisions were made to the Enhanced Periodic Review Template.

Glen Smith made a motion for approval.

Dan Grinkevich seconded the motion.

Kathleen Goodman abstained.

The review of Enhanced Periodic Review Template was approved as read.

Herb Schrayshuen suggested to also review the Guidelines along with the RSAW on all the yellow and red standards.

5.3 Approval of new Vice-Chair

NPCC Staff received two nominations for the position of Vice-Chair of the RSC, Quintin Lee of Eversource and Dan Grinkevich of Con Edison. Mr. Zito provided the RSC with background on the roles and responsibilities of the RSC Vice Chair.

Each nominee provided the RSC with a brief summary of their experience and qualifications.

Quintin Lee and Daniel Grinkevich left the room and RSC Members conducted a ballot.

Quintin Lee was elected vice Chair of the RSC.

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	6/7/17 Call-In
Project 2013-03 Geomagnetic Disturbance Mitigation	3/17/17 (I)		Mark Olson	1:00PM
Project 2016-03 Cyber Security Supply Chain Management	6/15/17 (F)	6/15/17 (I)	Mark Olson	1:15PM
Project 2016-02 Modifications to CIP Standards	4/11/17 (I)	2/8/17 (F)	Sean Cavote Mat Bunch	1:30PM
Project 2015-10 Single Points of Failure TPL-001	5/24/17 (I)		Latrice Harkness	1:45PM
Revisions to the NERC Standard Processes Manual	5/3/17 (F)	5/3/17 (I)	Chris Larson	2:00PM
Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	2/23/17 (F)		Darrel Richardson	2:15PM
Project 2015-09 Establish and Communicate System Operating Limits	8/12/16 (I)		Darrel Richardson	2:30PM
Project 2016-04 Modifications to PRC-025-1	4/3/17 (I)		Scott Barfield-McGinnis	2:45PM
Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards	4/13/17 (F)		Scott Barfield-McGinnis	3:00PM
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final				

Project 2013-03 Geomagnetic Disturbance Mitigation:

Mark Olson called into the meeting at 1:02PM.
The goal of the Standard Drafting Team (SDT)is to post an initial draft in the next few weeks.
The SDT is addressing three FERC directives issued when TPL-007-1 was approved.
FERC had specific concerns on spatial averaging, elements of the corrective action plan and ~~the Planning Coordinators acquisition of data a~~ the acquisition of geomagnetically-induced current (GIC) data.

Project 2016-03 Cyber Security Supply Chain Management:
John Helme Chair of TFIST called into the meeting at 1:18PM.
Mark Olson provided a summary on the proposed changes to the Implementation Guidance documents.
The SDT is focused on developing an Implementation Guidance document instead of a policy document.
~~If CIP-005 and CIP-006 pass an additional ballot will not be necessary.~~

Project 2016-02 Modifications to CIP Standards:
Mat Bunch called into the meeting at 1:30PM.
The SDT is working on the Implementation Guidance document for Project 2016-02.
The SDT is nearing completion on developing CIP-012.
The virtualization sub-team is preparing an informal comment period to collect additional information from the industry.
There are some concerns on the functional obligation of Transmission Operators Control Center.
TOCC sub-team is revising CIP-002 and is not planning to add any new security control requirements for low impact control centers.

Project 2015-10 Single Points of Failure TPL-001:
Latrice Harkness called into the meeting at 1:40PM.
The project is to address FERC Order 783.
The SDT is currently meeting this week to review all the comments from initial posting.

Revisions to the NERC Standard Processes Manual:
Chris Larson called into the meeting at 1:59PM.
The SPM failed a ballot with 64 percent approval.
~~There were concerns on section 7 of SPM~~There were concerns on section 7 involving the process for developing an interpretation.
Also, there were concerns on section 6 regarding the need for additional clarity on responsibilities during field testing.
Lauren Perotti and Latrice Harkness are looking to get a small team to review and respond to the comments and potentially submit for an additional ballot.

Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards:
Darrel Richardson called into the meeting at 2:10PM.
The SDT reviewed all the comments submitted during the informal comment period.
The SDT has drafted a SAR to address proposed revisions in PER-003.

The recommendation is to retire PER-004 and a SAR will be submitted to the SC for approval next week.

Project 2015-09 Establish and Communicate System Operating Limits:
The SDT removed one requirement from FAC-010 and will suggested to retiring FAC-010.
The SDT is recommending a new standard FAC-015.
The PC will have to use the same responsibilities/requirement as RC.
The SDT is proposing additional clarity by creating a new definition of SOL exceedance.
The goal is to post an initial draft document in September 2017.

Project 2016-04 Modifications to PRC-025-1:
Scott Barfield-McGinnis called into the meeting at 2:29PM.
The goal is to post an initial draft of the standard by July 19, 2017
Two primary concerns:

1. Hydro Quebec and entities out in West Coast have the issue of long transmission lines connected to generation at the end of the line.
2. Loadability issues with Distributed Generation Resources (DGR).

The SDT will also consider four other issues for improving clarity in the relay table.
The SDT will begin a two-week quality review starting next week.
The SDT will meet during the third week of September 2017 to respond to comments.

Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards:
The SDT has decided to reaffirm the standard and will not propose any changes.
All of the supporting information will be posted onto the Project page.

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.

6.4 TPL-007-2 and Proposal to cut USGS Magnetism Program
Guy Zito presented the redline of TPL-007-02 redline with his comments.
There is a concern regarding proposed budget cuts to the USGS Magnetism Program which supports the field magnetometers used to obtain the data required in TPL-007-1.

7.0 NERC Drafting Team Nominations

7.1 Currently Posted Drafting Team Vacancies
7.1.1 None at this time

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)
7.2.1 None at this time

7.3 Solicitation for Informal Development Teams
7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

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

8.1 Current Activities:

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

Ruida Shu gave a presentation on the status of PRC-006-NPCC-02 Automatic UFLS.

The SDT agreed on submitting all comments on the redline of PRC-006-NPCC-02 to Ruida Shu by July 7, 2017.

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

Guy Zito provided a status update to the PRC-006-3 Automatic UFLS Quebec Variance. The proposed variance has been approved by the NPCC BOD and is currently posted by NERC to receive comments on process adherence. Subsequent to the NERC posting the revised variance will be presented to the NERC BOT for approval.

9.0 NPCC Non-Standards

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

9.1 Directories:

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

Directory#8 has been reformatted consistent with NERC style requirements. Additionally, the battery testing intervals have been revised to ensure consistency with PRC -005-2 and three NPCC Glossary terms (Basic Minimum Power System. Key Facilities and Critical Components) have been revised. D#8 has been posted to the Open Process for three postings and the TFCO has responded to all comments. Presently the TFCO is preparing the revised document for presentation to the RCC in September.

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

The TFCO has proposed retiring Directories #9 and #10 concurrent with the full enforcement date of MOD-025-2 in July 2019. The RCC approved the TFCO retirement recommendation on May 31st, 2017 and the proposal is currently pending ballot approval by the NPCC Full Member Committee.

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

TFSP review of Directory#7 pending FERC approval of PRC-012-2. TFSS considering reliability implications of removing those existing SPS's that do not conform to the definition of a RAS (including one Type I SPS).

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

The CP-11 Working Group is conducting a review of the A-10 criteria in order to consider existing and alternative methodologies to identify critical facilities for applicability of the NPCC criteria.

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

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

  Action Item:

  Michael Jones, Herb Schrayshuen and Quintin Lee volunteered to assist Gerry Dunbar on incorporating the content of the A-01 document into the Directory Manual in order to retire the A-01.

  Status Report by next RSC meeting August 23, 2017.

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

TFCO Working Groups CO-1 and CO-8 currently reformatting criteria in both Directories into NERC style requirements and reviewing content to ensure criteria remains consistent with recent NERC standard revisions.

10.0 RSC Member Items of Interest

10.1 RSC Roster

The members of RSC reviewed the roster and removed Si-Truc Phan as Co-Vice Chair, updated information on Sector 4 NYPA and Dominion.

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

11.6 FERC Technical Conference on June 22, 2017

12.0 NERC Meetings

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

January 18th - Call	March 15th - Meeting	April 19th - Call
June 14th - Meeting	July 19th - Call	September 7th Meeting
October 18th - Call	December 6th - Meeting	

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

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

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

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

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

13.0 NERC Items of Interest (Since last RSC Meeting)

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

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

13.2 Alerts

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

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

13.3 Standard Committee 2017 Meeting Schedule

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

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

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

14.2 NPCC Board of Directors Meeting (BOD) 2017

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

14.3 NPCC Business Plan and Budget 2018

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2017 Meeting Dates

March 8th-9th, FRCC, Tampa FL
June 7th-8th, Saratoga NY
August 23rd-24th, Toronto
October 11th-12th, Lewiston NY
December 7th, Boston MA

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

January 20	February 3	February 17
March 24	April 7	April 21
May 5	May 19	June 16
June 30	July 14	July 28
August 11	September 8	September 22
September 29	October 27	November 10
November 24	December 22	

The meeting is adjourned at 11:05AM on June 8, 2017.

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
2010-05.2	Remedial Action Schemes (Phase 3 of Protection Systems)	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2013-03	Geomagnetic Disturbance Mitigation	Standard	Per-Anders Lof Rui Sun	National Grid Dominion	781-907-5581	per-anders.lof@nationalgrid.com
2014-01	Standards Applicability for Dispersed Generation Resources	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com
2015-03	Periodic Review of System Operating Limit Standards	Standard	Dean Laforest Sam Jager	ISO-NE IESO		
2015-09	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 Philippe Labrosse	Dominion Resource Services, Inc. Hydro-Quebec TransEnergie		
2016-03	Cyber Security Supply Chain Management	Standard	Norm Dang David Bryan Gayle	IESO Dominion Resource Services, Inc.		
2016-04	Modifications to PRC-025-1	Standard	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				

Source = NERC Standard Drafting Team Rosters - September 2016

NPCC Representatives on NERC Standards Drafting Teams						
Project No.	**Project Title**	**DT Type**	**NPCC Representatives**	**Company**	**Telephone**	**E-mail Address**
2007-06	Phase 1: System Protection Coordination	Standard	None			
2007-06.2	Phase 2: System Protection Coordination	Standard	Ruida Shu Po Bun Ear	NPCC Hydro-Quebec TransEnergie	917-934-7976	rshu@npcc.org ear.po-bun@hydro.qc.c
2007-11	Disturbance Monitoring	Standard	Lee Pedowicz	NPCC	212-840-1070	lpedowicz@npcc.org
2007-17.4	PRC-005 FERC Order No. 803 Directive	Standard				
2008-02	Undervoltage Load Shedding	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2009-02	Real-time Monitoring and Analysis Capabilities	Standard	T.J. (Tim) Kucey	PSEG Fossil, LLC		Timothy.Kucey@pseg.com
2009-03	Emergency Operations	Standard	Connie Lowe	Dominion Resource Services, Inc.	804-819-2917	connie.lowe@dom.com
2010-03	Modeling Data (MOD B)	Standard				
2010-05.1	Protection Systems: Phase 1 (Misoperations)	Standard	Paul Difilippo	Hydro One Networks	647-328-7068	paul.difilippo@hydroone.com
2010-05.2	Remedial Action Schemes (Phase 3 of Protection Systems)	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2010-13.3	Phase 3 of Relay Loadability: Stable Power Swings	Standard				
2010-14.1	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard				
2010-14.2	Balancing Authority Reliability-Based Control, Phase 2	Standard			-	
2010-14.2.2	Periodic Review of BAL Standards - BAL-004	Standard				
2012-09	IRO Five-Year Review	Standard	John Mulhern	Con Edison	212-580 6791	mulhernj@coned.com
2013-03	Geomagnetic Disturbance Mitigation	Standard	Emanuel Bernabeu	Dominion	804-432-8780	emanuel.e.bernabeu@dom.com
			Kenneth Fleischer	NextEra Energy	561-691-2456	kenneth.fleischer@fpl.com
			Luis Marti	Hydro One Networks	416-345-5317	luis.marti@hydroone.com
2013-04	Voltage and Reactive Control (VAR)	Standard	Sharma Kolluri	Entergy	504-576-4045	vkollur@entergy.com
2014-01	Standards Applicability for Dispersed Generation Resources	Standard	Brian Evans-Mongeon	Utility Services	802-241-1400	brian.evans-mongeon@utilitysvcs.com
2014-02	Critical Infrastructure Protection Standards Version 5 Revisions	Standard	Greg Goodrich	NYISO	518-356-7591	ggoodrich@nyiso.com
2014-03	Revisions to TOP/IRO Reliability Standards	Standard				
2014-04	Physical Security	Standard	Kathy Judge	National Grid	508-860-6040	kathleen.judge@nationalgrid.com
2015-02	Emergency Operations Periodic Review	Standard	Connie Lowe	Dominion	804-819-2917	connie.lowe@dom.com
2015-03	Periodic Review of System Operating Limit Standards	Standard	Dean Laforest	ISO-NE		
2015-04	Alignment of NERC Glossary of Terms and Definitions Used in the	Standard	Jill Loewer	Utility Services	802-241-1400	jill.loewer@utilitysvcs.com
2015-06	Interconnection Reliability Operations and Coordination - IRO-006-I	Standard				
2015-07	Internal Communications Capabilities - COM-001	Standard				
2015-08	Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008	Standard	Connie Lowe Karen Backman	Dominion IESO	804-819-2917	Connie.lowe@dom.com
Source = NERC Standard Drafting Team Rosters - June 2015						
Projects Added:						
1. Project 2015-06 Interconnection Reliability Operations and Coordination - IRO-006-East and IRO-009						
2. Project 2015-07 Internal Communications Capabilities - COM-001						
3. Project 2015-08 Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008						

NPCC Document Open Process Executive Tracking Summary

Revised: **7/5/2017** Further details regarding the individual documents may be found at: https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

Line No.	Type	Document	Description	Latest Revision	Comments	Status
1	Criteria	A-01	Criteria for Review and Approval of Documents	Apr-17		NPCC Full Members approved a revised version of A-01 on April 21st, 2017.
2	Criteria	A-10	Classification of BPS Elements	Dec-09	CP-11 Review underway.	TFCP approved the A-10 Review Scope of Work. CP-11 review currently underway in accordance with the Scope of Work.
3	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System	Feb-13	TFSP Updated in January 2017	TFSP reviewing Open Process Comments.
4	Procedure	C-01	NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures	Jun-16	Revised.	TFCO Completed Update June 2016.
5	Procedure	C-15	Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems	Jun-16	Revised.	TFCO Completed Update June 2016.
6	Procedure	C-25	Procedure to Collect Power System Event Data	Sep-07		TFSS to Review and Update for Inclusion in D#11 as Appendix or Recommend Retirement.
7	Procedure	C-33	Procedure for Analysis and Classification of Dynamic Control Systems	Apr-06		Pending TFSS review.
8	Procedure	C-43	NPCC Operational Review for the Integration of New facilities	Aug-08	Pending TFCO review.	TFCP to review Open Process Comments.
9	Procedure	C-45	Procedure for Analysis and Reporting of Protection System Misoperations	Jul-16	Revised.	TFSP revised C-45 July, 2016.

NPCC Directory Executive Tracking Summary

Revised: 7/5/2017 Further details regarding the individual documents may be found at:

	Document	Developed From	Title of Directory	Responsible Task Force	Latest Version	Comments	Status
1	Directory #1	Criteria A-2	Design and Operation of the Bulk Power System	TFCP	Oct-15		
2	Directory #2	Criteria A-3	Emergency Operations	TFCO	Jun-09		TFCO Working Group CO-8 reviewing reformatted draft of Directory#2.
3	Directory #3	Criteria A-4	Maintenance Criteria for Bulk Power System Protection	TFSP	Jun-09	Directory#3 retired effective April 1st, 2015 coinciding with the enforcement date of PRC -005-2.	
4	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	TFSP	Oct-15		
5	Directory #5	Criteria A-6	Reserve	TFCO	Oct-12		TFCO Working Group CO-1 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		Pending approval of PRC-012-2 TFSP to consider review of Directory#7 criteria and NPCC Glossary definition of SPS.
8	Directory #8	Criteria A-12	System Restoration	TFCO	Oct-10		Subsequent to PRC-005-2 approval TFCO has revised battery testing criteria. Pending RCC approval.
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	TFCO	Dec-11		TFCO posted recommendation to retire D#9 and D#10 pending full enforcement of MOD-25-2. (July 2019). Pending Full Member approval ballot.
10	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	TFCO	Dec-11		See D#9.
11	Directory#11	Criteria A-15	Disturbance Monitoring	TFSP	Oct-16	D#11 Approved October 2016.	
12	Directory#12		UFLS	TFSS	Oct-12		

NPCC Directory Criteria Clarifications

Revised: **7/5/2017** Further details regarding the individual documents may be found at: https://www.npcc.org/Standards/Directory%20Interpretations/Forms/Public%20List.aspx

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

7/5/2017

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

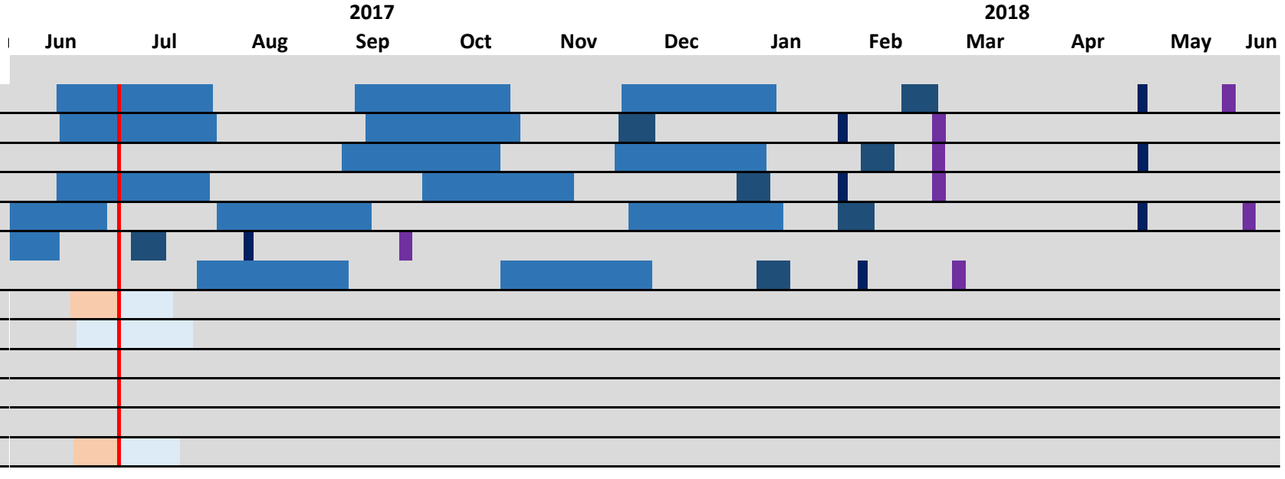
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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

Updated: 7/3/2017

Nom-SAR/D | QR | Posting-SAR or PR | Posting-Comment Only | Posting Comment & Ball | Final Ballot | Present to BO | Filing / Post Approval Train

HOME	DO NOT SORT (Filtering Ok)	Early/(Late)	Baseline/ Current
Project (Filter)	Deliverables (Filter)	Days (Filter)	(Filter)
2013-03 - Geomagnetic Disturbance Mitigatior	TPL-007-2		Current
2015-09 - Establish and Communicate System	FAC-010-3, FAC-011-3, and FA	(330)	Current
2015-10 - Single Points of Failure TPL-001	TPL-001	(31)	Current
2016-02 - Modifications to CIP Standards	Directives, Control Center Com	(77)	Current
2016-02 - Modifications to CIP Standards	V5TAG issues: Cyber Asset and	(107)	Current
2016-03 - Cyber Security Supply Chain Manage	New and revised Standard(s)	(16)	Current
2016-04 - Modifications to PRC-025-1	PRC-025-2		Proposed
2017-01 - Modifications to BAL-003-1	BAL-003-2		Proposed
2017-02 - Modifications to Personnel Performa	PER-003-2, retire PER-004-2		Proposed
2017-03 - Periodic Review of FAC-008-3 Standa	Periodic Review Recommenda		Proposed
2017-04 - Periodic Review of Interchange Sche	Periodic Review Recommenda		Proposed
2017-05 - Project 2017-05 NUC-001-3 Periodic	Periodic Review of NUC-001-3		Proposed
2017-06 - Project 2017-06 Modifications to BA	BAL-002-3		Proposed



Project Name	Status	Comments	Deliverable	Deadline	Priority in RSDP, click to see applicable Footnote	P81 Req (2013)	Number of Directives	No. of Guidances (see Note 2)	Directionally consistent with IERP findings (See Note 5)	Developer	PMOS Liaison	Affected Standards	Last Updated
(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
Geomagnetic Disturbance Mitigation	Working to Initial Ballot	FERC issued Order No. 830 on September 22, 2016 approving TPL-007-1 and directing modifications. The SDT will develop revised or new requirements to enhance the benchmark GMD event used in GMD assessments, require collection of GMD data, and establish deadlines for GMD Corrective Action Plans and mitigation measures. Revisions must be filed by May 29, 2018. The SAR was accepted by the Standards Committee on March 15, 2017. The team anticipates posting the week of June 26, 2017 once they know what white papers and other documents need to accompany development.	TPL-007-2	5/29/2018	High	N/A	4	N/A	N/A	Mark Olson	Jennifer Sterling	TPL-007-1	6/27/2017
Establish and Communicate System Operating Limits	Working to Initial Ballot	The drafting team met in Denver, CO February 15-17, 2017 and in Atlanta, GA April 4 – 6, 2017. The team is meeting in Folsom, CA on June 13 – 15, 2017. The team continues to work on a baseline schedule.	FAC-010-3, FAC-011-3, and FAC-014-2	N/A	Medium	N/A	N/A	N/A	N/A	Darrel Richardson & Al McMeekin	Ken Lanehome	FAC-010-3, FAC-011-3, and FAC-014-2	6/27/2017
Single Points of Failure TPL-001	Responding to Comment	The 30-day informal comment period end on May 24, 2017. The goal is to seek approval to post at the July 2017 SC meeting for a 45-day formal comment and initial ballot period.	TPL-001	N/A	High	N/A	2 directives at P40 & P89 (Click this link for FERC Order)	N/A	N/A	Latrice Harkness	Mark Pratt	TPL-001	6/13/2017
Modifications to CIP Standards	Responding to Comment	The SDT is considering comments from the March 2017 informal posting.	Directives, Control Center Comm Nets (CIP-006)	N/A	High	N/A	2	N/A	N/A	Mat Bunch & Katherine Street	Ken Lanehome and Ash Mayfield		6/27/2017
Modifications to CIP Standards	Responding to Comment	Two concurrent 29-day informal comment periods ended April 11, 2017, for stakeholders to provide feedback on the Standard Drafting Team's (SDT's) approaches to addressing two issues from the Version 5 Transition Advisory Group (V5TAG): (1) the applicability of the CIP Reliability Standards to BES Cyber Systems for a Transmission Owner Control Center performing the functional obligations of a Transmission Operator; and, (2) the use of virtualization in the CIP environment.	V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), TO Control Centers Performing Transmission Operator (TOP) Obligations	N/A	High	N/A	N/A	N/A	N/A	Mat Bunch & Katherine Street	Ken Lanehome and Ash Mayfield	CIP Stds. - Unknown	6/27/2017
Cyber Security Supply Chain Management	Responding to Comment	The project will address directives from Federal Energy Regulatory Commission (FERC) Order No. 829 to develop a new or modified standard to address "supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations." See Order No. 829, at P1. All three standards passed overwhelmingly. The team met on June 21 & 22, 2017 are considering next steps	New and revised Standard(s)	9/27/2017	N/A	N/A	1	N/A	N/A	Mark Olson	Brenda Hampton and Angela Kimmey	CIP-005-6, CIP-010-3, and CIP-013-1	6/27/2017
Modifications to PRC-025-1	Working to Initial Ballot	The Standards Committee (SC) accepted the SAR on April 19, 2017 and appointed the SAR drafting team as the standard drafting team (SDT). The SDT had its first meeting in-person at NERC in Atlanta, GA from May 15-18. The SDT is currently socializing the revisions and anticipates delivering the revised PRC-025-2 standard to the SC on July 19, 2017.	New and revised Standard(s)	None, enhancemens to 025 affects entities currently implementing version 1 under the five and seven year implementation period. The first period ends October 1, 2019 and the second on October 1, 2021. Project must consider the time for development and subsequent regulatory approvals.	Has not been prioritized.	N/A	N/A	N/A	Yes	Scott Barfield-McGinnis	Charles Yeung	PRC-025-1	6/27/2017

Project	**2013-03**	**Home**
Project Name	Geomagnetic Disturbance Mitigation	
Status	Working to Initial Ballot	
Comments	FERC issued Order No. 830 on September 22, 2016 approving TPL-007-1 and directing modifications. The SDT will develop revised or new requirements to enhance the benchmark GMD event used in GMD assessments, require collection of GMD data, and establish deadlines for GMD Corrective Action Plans and mitigation measures. Revisions must be filed by May 29, 2018. The SAR was accepted by the Standards Committee on March 15, 2017. The team anticipates posting the week of June 26, 2017 once they know what white papers and other documents need to accompany development.	
Deliverable	TPL-007-2	
Deadline	**Tuesday, May 29, 2018**	
Priority in RSDP, click to see applicable Footnote	High	
P81 Req (2013)	N/A	
Number of Directives	4	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mark Olson	
PMOS Liaison	Jennifer Sterling	
Affected Standards	TPL-007-1	
Last Updated	6/27/2017	

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	10/20/2016	11/9/2016	10/20/2016	11/9/2016			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	12/16/2016	1/20/2017	12/20/2016	1/19/2017	4		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	*6/15/2017*	*7/30/2017*	*6/15/2017*	*7/30/2017*			
CAB - Com/Add Ballot 2	9/11/2017	10/26/2017	9/11/2017	10/26/2017			
CAB - Com/Add Ballot 3	11/29/2017	1/13/2018	11/29/2017	1/13/2018			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	2/20/2018	3/2/2018	2/20/2018	3/2/2018			
PTB - Present to BOT	5/1/2018	5/3/2018	5/1/2018	5/3/2018			
Filing - Filing with Regulators	5/26/2018	5/29/2018	5/26/2018	**5/29/2018**			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
No dates provided	6/1/2016	Project finished prior to 2015.
Accept Baseline Schedule	6/14/2017	Accepted by unamious consent.

Project	**2015-09**
Project Name	Establish and Communicate System Operating Limits
Status	Working to Initial Ballot
Comments	The drafting team met in Denver, CO February 15-17, 2017 and in Atlanta, GA April 4 – 6, 2017. The team is meeting in Folsom, CA on June 13 – 15, 2017. The team continues to work on a baseline schedule.
Deliverable	FAC-010-3, FAC-011-3, and FAC-014-2
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	Darrel Richardson & Al McMeekin
PMOS Liaison	Ken Lanehome
Affected Standards	FAC-010-3, FAC-011-3, and FAC-014-2
Last Updated	6/27/2017

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review			4/4/2016	4/14/2016		Not needed	
SP1 - SAR/PR/WP Posting 1	8/20/2015	9/21/2015	8/20/2015	9/21/2015			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	7/14/2016	8/12/2016	7/8/2016	8/7/2016	(6)		
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	***6/16/2017***	***7/31/2017***	4/18/2016	6/2/2016	(424)		
CAB - Com/Add Ballot 2	9/14/2017	10/29/2017	7/18/2016	9/1/2016	(423)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	11/28/2017	12/8/2017	1/2/2017	1/12/2017	(330)		
PTB - Present to BOT	2/1/2018	2/3/2018	2/1/2017	2/3/2017	(365)		
Filing - Filing with Regulators	3/1/2018	3/4/2018	3/1/2017	3/4/2017	(365)		
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	**2015-10**
Project Name	Single Points of Failure TPL-001
Status	Responding to Comment
Comments	The 30-day informal comment period end on May 24, 2017. The goal is to seek approval to post at the July 2017 SC meeting for a 45-day formal comment and initial ballot period.
Deliverable	TPL-001
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	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
Last Updated	6/13/2017

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	11/12/2015	12/1/2015	1/18/2016	2/1/2016	67		
Nominations - DT	7/22/2016	8/5/2016	7/25/2016	8/8/2016	3		
QR - Quality Review			5/30/2016	6/9/2016			
SP1 - SAR/PR/WP Posting 1	11/12/2015	12/17/2015	11/12/2015	12/17/2015			
SP2 - SAR/PR/WP Posting 2	5/26/2016	6/24/2016	6/15/2016	7/15/2016	20	Expanded Scope	
CP1 - Comment Period 1	4/25/2017	5/24/2017	4/25/2017	5/24/2017		Other	Team added informal comment period
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/7/2017	10/23/2017	7/5/2017	8/18/2017	(64)		
CAB - Com/Add Ballot 2	11/27/2017	1/10/2018	10/18/2017	12/1/2017	(40)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	2/8/2018	2/17/2018	***1/8/2018***	***1/17/2018***	(31)		
PTB - Present to BOT	5/1/2018	5/3/2018	2/1/2018	2/3/2018	(89)		
Filing - Filing with Regulators	3/1/2018	3/4/2018	3/1/2018	3/4/2018			
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
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.

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Responding to Comment
Comments	The SDT is considering comments from the March 2017 informal posting.
Deliverable	Directives, Control Center Comm Nets (CIP-006)
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	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 & Katherine Street
PMOS Liaison	Ken Lanehome and Ash Mayfield
Affected Standards	
Last Updated	6/27/2017

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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							
CIB - Com/Ballot 1 (Initial)	***6/15/2017***	***7/29/2017***	12/2/2016	1/16/2017	(195)		
CAB - Com/Add Ballot 2	10/1/2017	11/14/2017	3/31/2017	5/15/2017	(184)		
CAB - Com/Add Ballot 3			8/15/2017	9/29/2017			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/2/2018	1/11/2018	10/17/2017	10/27/2017	(77)		78.55%
PTB - Present to BOT	2/1/2018	2/3/2018	11/7/2017	11/9/2017	(86)		
Filing - Filing with Regulators	3/1/2018	3/4/2018	12/28/2017	12/31/2017	(63)		
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.

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Responding to Comment
Comments	Two concurrent 29-day informal comment periods ended April 11, 2017, for stakeholders to provide feedback on the Standard Drafting Team's (SDT's) approaches to addressing two issues from the Version 5 Transition Advisory Group (V5TAG): (1) the applicability of the CIP Reliability Standards to BES Cyber Systems for a Transmission Owner Control Center performing the functional obligations of a Transmission Operator; and, (2) the use of virtualization in the CIP environment.
Deliverable	V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), TO Control Centers Performing Transmission Operator (TOP)
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	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 & Katherine Street
PMOS	Ken Lanehome and Ash Mayfield
Affected Standards	CIP Stds. - Unknown
Affected Standards	6/27/2017

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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)	5/15/2017	6/29/2017	12/2/2016	1/16/2017	(164)		
CAB - Com/Add Ballot 2	8/1/2017	9/15/2017	3/31/2017	5/15/2017	(123)		
CAB - Com/Add Ballot 3	12/1/2017	1/15/2018	8/15/2017	9/29/2017	(108)		
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	2/1/2018	2/11/2018	10/17/2017	10/27/2017	(107)		
PTB - Present to BOT	5/1/2018	5/3/2018	11/7/2017	11/9/2017	(175)		
Filing - Filing with Regulators	6/1/2018	6/4/2018	12/28/2017	12/31/2017	(155)		
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.

Project **2016-03** [Home]

Project Name	Cyber Security Supply Chain Management
Status	Responding to Comment
Comments	The project will address directives from Federal Energy Regulatory Commission (FERC) Order No. 829 to develop a new or modified standard to address "supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations." See Order No. 829, at P1. All three standards passed overwhelmingly. The team met on June 21 & 22, 2017 are considering next steps.
Deliverable	New and revised Standard(s)
Deadline	**Wednesday, September 27, 2017**
Priority in RSDP, click to see applicable Footnote	N/A
P81 Req (2013)	N/A
Number of Directives	1
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mark Olson
PMOS Liaison	Brenda Hampton and Angela Kimmey
Affected Standards	CIP-005-6, CIP-010-3, and CIP-013-1
Last Updated	6/27/2017

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	7/29/2016	8/18/2016	7/29/2016	8/18/2016			
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	10/20/2016	11/18/2016	10/20/2016	11/21/2016			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	1/19/2017	3/6/2017	1/19/2017	3/6/2017			
CAB - Com/Add Ballot 2	5/2/2017	6/15/2017	4/12/2017	5/26/2017	(20)		CIP-005-6 89.84% CIP-010-3 82.92% CIP-013-1 88.64%
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	7/7/2017	7/16/2017	6/21/2017	6/30/2017	(16)		
PTB - Present to BOT	8/9/2017	8/11/2017	8/9/2017	8/11/2017			
Filing - Filing with Regulators	9/24/2017	9/27/2017	9/24/2017	**9/27/2017**			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Create project record	8/1/2016	Added project to PTS.
Periodic Update	8/21/2016	Added FERC deadline.
Baseline Schedule	11/30/2016	SDT determined the schedule.
Present Schedule to SC	3/15/2017	Accepted the SDT project schedule.
Removed Liaison	4/14/2017	Removed R. Kinard due to resigning from PMOS.

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Project	2016-04
Project Name	Modifications to PRC-025-1
Status	Working to Initial Ballot
Comments	The Standards Committee (SC) accepted the SAR on April 19, 2017 and appointed the SAR drafting team as the standard drafting team (SDT). The SDT had its first meeting in-person at NERC in Atlanta, GA from May 15-18. The SDT is currently socializing the revisions and anticipates delivering the revised PRC-025-2 standard to the SC on July 19, 2017.
Deliverable	PRC-025-2
Deadline	None, enhancemens to 025 affects entities currently implementing version 1 under the five and seven year implementation period. The first period ends October 1, 2019 and the second on October 1, 2021. Project must consider the time for development and subsequent regulatory
Priority in RSDP, click to see applicable Footnote	Has not been prioritized.
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	Yes
Developer	Scott Barfield-McGinnis
PMOS Liaison	Charles Yeung
Affected Standards	PRC-025-1
Last Updated	6/27/2017

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	9/16/2016	9/28/2016	9/16/2016	9/28/2016			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	9/16/2016	10/18/2016	9/16/2016	10/18/2016			
SP2 - SAR/PR/WP Posting 2	3/20/2017	4/3/2017	3/2/2017	4/1/2017	(18)		
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	7/26/2017	9/8/2017	7/26/2017	9/8/2017			
CAB - Com/Add Ballot 2	10/24/2017	12/7/2017	10/24/2017	12/7/2017			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/8/2018	1/17/2018	1/8/2018	1/17/2018			
PTB - Present to BOT	2/7/2018	2/9/2018	2/7/2018	2/9/2018			
Filing - Filing with Regulators	3/7/2018	3/10/2018	3/7/2018	3/10/2018			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
SC Authorized Posting	9/14/2016	SAR and SAR SDT nominations.
Accept Baseline Schedule	7/27/2017	TBD

Project	**2017-01**
Project Name	Modifications to BAL-003-1
Status	Other
Comments	Waiting for project to be stood up.
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	
Affected Standards	BAL-003-1
Last Updated	7/3/2017

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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	6/19/2017	7/3/2017	6/19/2017	7/3/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/19/2017	7/18/2017	6/19/2017	7/18/2017			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	

Home

Project	**2017-02**
Project Name	Modifications to Personnel Performance, Training, and Qualifications Standards
Status	Other
Comments	Waiting for project to be activated by the Standards Committee, which is anticipated on June 14, 2017.
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	
Affected Standards	PER-003-1 & PER-004-2
Last Updated	7/3/2017

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							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)							
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	

Project	**2017-03**	**Home**
Project Name	Periodic Review of FAC-008-3 Standard	
Status	Nominations	
Comments	Nominations are being sought for periodic review team members through 8 p.m. Eastern, Tuesday, May 23, 2017. The Standards Committee is expected to appoint team members July 2017.	
Deliverable	Periodic Review Recommendations	
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	Al McMeekin	
PMOS Liaison		
Affected Standards	FAC-008-3	
Last Updated	7/3/2017	

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
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	

Project	2017-04	Home
Project Name	Periodic Review of Interchange Scheduling and Coordination Standards	
Status	Nominations	
Comments	Nominations are being sought for periodic review team members through 8 p.m. Eastern, Monday, May 15, 2017. The Standards Committee is expected to appoint team members July 2017.	
Deliverable	Periodic Review Recommendations	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Laura Anderson	
PMOS Liaison		
Affected Standards	INT-004, INT-006, INT-009, and INT-010	
Last Updated	7/3/2017	

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
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	

Project	2017-05	Home
Project Name	Project 2017-05 NUC-001-3 Periodic Review	
Status	Other	
Comments	Nominations are being sought for periodic review team members through 8 p.m. Eastern, Tuesday, May 23, 2017. The Standards Committee is expected to appoint team members July 2017.	
Deliverable	Periodic Review of NUC-001-3 Standard	
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	Mat Bunch	
PMOS Liaison		
Affected Standards	NUC-001-3	
Last Updated	7/3/2017	

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
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	

Project	**2017-06**
Project Name	Project 2017-06 Modifications to BAL-002-2
Status	Posted
Comments	SAR is posted for a 30 day informal comment period.

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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	
Affected Standards	BAL-002-2
Last Updated	7/3/2017

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	6/20/2017	7/3/2017	6/20/2017	7/3/2017	0		
Nominations - DT					0		
QR - Quality Review					0		
SP1 - SAR/PR/WP Posting 1	*6/20/2017*	*7/20/2017*	*6/20/2017*	*7/20/2017*	0		
SP2 - SAR/PR/WP Posting 2					0		
CP1 - Comment Period 1					0		
CP2 - Comment Period 2					0		
CIB - Com/Ballot 1 (Initial)					0		
CAB - Com/Add Ballot 2					0		
CAB - Com/Add Ballot 3					0		
CAB - Com/Add Ballot 4					0		
CAB - Com/Add Ballot 5					0		
FB - Final Ballot					0		
PTB - Present to BOT					0		
Filing - Filing with Regulators					0		
PT - Post Approval Training					0		

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/30/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	

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.
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 (Placeholder)
Note 10	

RSC Meeting #17-3, 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 draft A-01 Criteria document. Status Report by next RSC meeting.	Gerry Dunbar	8/23/17	Ongoing
4.2				

DRAFT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Weekly Standards & Compliance Bulletin

August 14–20, 2017

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2016-04 – Modifications to PRC-025-1	Initial Ballot and Non-binding Poll	08/29/17	09/07/17
Project 2016-02 – Modifications to CIP Standards | CIP-012-1	Initial Ballot and Non-binding Poll	09/01/17	09/11/17
Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2016-04 – Modifications to PRC-025-1	Join Ballot Pools	07/25/17	08/23/17
Project 2016-02 – Modifications to CIP Standards | CIP-012-1	Join Ballot Pools	07/27/17	08/25/17
Posted for Comment (comment periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
A draft RSAW for Project 2013-03 – Geomagnetic Disturbance Mitigation is posted through August 25, 2017.	Submit comments to RSAWfeedback@nerc.net.	06/28/17	08/25/17
Project 2017-07 – Standards Alignment with Registration | Standards Authorization Request	Comment Period	08/01/17	08/30/17
Project 2017-07 – Standards Alignment with Registration | Standards Authorization Request for MOD-032-1	Comment Period	08/01/17	08/30/17
Project 2016-04 – Modifications to PRC-025-1 A draft RSAW is posted through September 7, 2017. Submit comments to RSAWfeedback@nerc.net.	Comment Period	07/25/17	09/07/17
Project 2016-02 – Modifications to CIP Standards | CIP-012-1	Comment Period	07/27/17	09/11/17

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
Comment Period Open for Integrating Inverter-based Resources into Weak Power Systems Draft Reliability Guideline: The Integrating Inverter-based Resources into Weak Power Systems Draft Reliability Guideline provides the electric utility industry with background and useful reference information pertaining to the topics of identifying weak grid conditions and potential issues that may arise from weak grids when connecting or operating inverter-based resources. The goal is to proactively provide the industry with information for their consideration as they face this emerging issue and increasing penetrations of inverter-based resources. The NERC Planning Committee reviewed this draft guideline at the June 2017 meeting and approved it for a 45-day industry comment period.	Submit comments to reliabilityguidelinecomments@nerc.net using the comment matrix.	07/11/17	08/25/17
Comment Period Open for Area Control Error Diversity Interchange Process V2 Draft Reliability Guideline: The NERC Operating Committee's Resources Subcommittee developed the draft Reliability Guideline: Area Control Error Diversity Interchange (ADI) Process V2. This Reliability Guideline is intended to provide recommended practices related to the usage of ADI. ADI processes depend on the timely exchange of relevant data and consistent implementation of ADI 91 adjustments in the same time frame of EMS scan rates (e.g., six seconds, or less). While the information 92 exchange processes used for ADI have very high availability, BAs	Submit comments via email using the comment form.	07/19/17	08/31/17

participating in ADI have backup plans to 93 address failures in data exchange communications. The NERC Operating Committee reviewed the initial draft of the guideline at its June 2017 meeting and approved it for a 45-day industry comment period. A redlined version of the guideline is available here.			
Comment Period Open for Operating Reserve Management Draft Reliability Guideline: The Operating Reserve Management Draft Reliability Guideline is intended to provide recommended practices for the management of an appropriate mix of Operating Reserve, as well as readiness to respond to loss of load events. It also provides guidance with respect to the management of Operating Reserve required to meet the NERC Reliability Standards. A redlined version of the draft is available here.	Submit comments via email using the comment form.	08/02/17	09/18/17
Comment Period Open for Inadvertent Interchange Draft Reliability Guideline: The Inadvertent Interchange Draft Reliability Guideline is intended to provide recommended practices for the management of Inadvertent Interchange (also referred to herein as inadvertent) accounting. With the goal of ensuring that, over the long term, BA Areas do not excessively depend on another BA Area in the Interconnection for meeting their demand or Interchange obligations. A redlined version of the draft is available here.	Submit comments via email using the comment form.	08/02/17	09/18/17

STANDARDS NEWS

Nomination Period Open for Project 2017-07 – Standards Alignment with Registration

Nominations are being sought for Project 2017-07 – Standards Alignment with Registration Standards Authorization Request drafting team members through **August 14, 2017**.

QUICK LINKS
Register in the SBS
Projected Standards Posting Schedule
Project Tracking Spreadsheet
Standards Related Questions – Single Portal
2017–2019 Reliability Standards Development Plan

Use the electronic form to submit a nomination. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the nomination form is posted on the 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.

The time commitment for this project is expected to be two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the team sets forth. Team members may also have side projects, either individually or by sub-group, to present for discussion and review. Lastly, an important component of the team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful ballot.

Previous drafting or periodic review team experience is beneficial, but not required. See the project page and unofficial nomination form for additional information. The Standards Committee is expected to appoint members to the team in September 2017. Nominees will be notified shortly after they have been selected.

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

NEW NERC Launches ERO Enterprise Program Alignment Process

During 2017, NERC and the Compliance and Certification Committee (CCC) focused numerous activities and discussions on how to improve consistency. To this end, NERC created the Consistency Framework, which the Board of Trustees Compliance Committee (BOTCC) discussed with NERC and the Regional Entities (REs). NERC staff presented the Consistency Framework at the NERC Trustees and RE Board Officers meeting in May and the CCC established the Consistency Working Group. As a result, NERC developed and implemented the ERO Enterprise Program Alignment Process, which replaces the Regional Consistency Reporting Process and Tool.

QUICK LINKS

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

NERC staff, who are responsible for managing the Program Alignment process, capture and track all issues report through the Consistency Reporting Tool in a central repository. The Consistency Reporting Tool, which is hosted by EthicsPoint by NAVEX Global, offers the option of anonymity to users. NERC and the REs will determine materiality and priority of issues and will also develop and implement recommendations. The Issues and Recommendations Tracking document is posted on the ERO Enterprise Program Alignment Process page in order to provide transparency for the industry.

The Program Alignment page, located under the Compliance and Enforcement program area on NERC.com, provides a link to the Consistency Reporting Tool along with other Program Alignment and Regional Program Information Resources. The NERC Rules of Procedure allows some flexibility for REs when designing and implementing certain procedures. The Regional Program Information Matrix captures where these differences exist and seeks to increase overall transparency.

A webinar on the Program Alignment Process will be conducted in late September or early October and will be announced in the Weekly Standards and Compliance Bulletin.

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)
October 1, 2017	COM-001-3 – Communications
	IRO-002-5 – Reliability Coordination – Monitoring and Analysis
January 1, 2018	BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
	PRC-026-1 – Relay Performance During Stable Power Swings (Requirement 1);
April 1, 2018	IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities
	TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities
July 1, 2018	CIP-009-6 – Cyber Security — Recovery Plans for BES Cyber Systems (Requirement 2.3); CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirements 3.2, 3.2.1, 3.2.2);
	MOD-026-1 – Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions (Requirements 2, 2.1–2.1.6); MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions (Requirements 2, 2.1–2.1.5);
	TOP-001-4 – Transmission Operations
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 2)
September 1, 2018	CIP-003-6 – Cyber Security – Security Management Controls (Requirement 2, Att. 1, Sec. 2 and 3);
January 1, 2019	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 5)
January 1, 2020	PRC-026-1 – Relay Performance During Stable Power Swings (Requirements 2–4)
July 1, 2020	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (50% compliance for Requirements 2–4, 6–11)
January 1, 2021	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements 6, 6.1–6.4)
January 1, 2022	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements 3,4,7)

July 1, 2022	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (100% compliance for Requirements 2–4, 6–11)
	VAR-501-WECC-3 – Power System Stabilizer (Requirement 3 has an effective date of July 1, 2022 for units placed in service prior to final regulatory approval.)

BOARD OF TRUSTEES AND FERC ACTION

NEW NERC Board Focuses on Cross-Border Collaboration; Approves Budget; Adopts Standards, Including Supply Chain

NERC held its quarterly Board of Trustees meeting in Ottawa on August 10. The Honorable James Gordon Carr, minister of Natural Resources Canada, welcomed participants to Canada during the country's 150th anniversary and lauded the cross-border partnerships in a videotaped greeting.

The Board approved the 2018 Business Plan and Budget, which includes funding that supports the long-term strategy for the Electricity Information Sharing and Analysis Center. The Board also adopted one new standard and modifications to four existing standards and two Regional standards. The Board also affirmed the review of two existing standards:

- CIP-013-1 Cyber Security – Supply Chain Risk Management requires entities to assess the security risks of vendor products and services when planning and procuring.
- CIP-005-6 Cyber Security – Electronic Security Perimeter modified to address vendor-initiated remote access.
- CIP-010-3 – Cyber Security – Configuration Change Management and Vulnerability Assessments modified to address software integrity and authenticity.
- PRC-006-3 – Automatic Underfrequency Load Shedding, NPCC Regional Variance for Quebec Interconnection, which defines a more accurate generation deficiency scenario applicable to the Québec Interconnection and serves to prevent unnecessary load shed.
- Modifications to BAL-002-2(i) Violation Risk Factors in response to FERC Order No. 835, which changes R1 and R2 VRFs from "medium" to "high."
- Regional standards: BAL-502-RF-03 – Planning Resource Adequacy Analysis, Assessment and Documentation and PRC-006-SERC-02 – Automatic Underfrequency Load Shedding Requirements.
- Project 2016 EPR-02 - Enhanced Periodic Review of Voltage and Reactive Standards, VAR-001-4.1 and VAR-00204, which made errata changes only.

In conjunction with the adoption of the supply chain standard, the Board directed that NERC and industry continue working on supply chain issues to include implementation guidance as appropriate, further study of supply chain risks and continued information sharing, among other activities.

For more information on Board action and the Board meeting, please view the announcement and presentations.

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

- Fifth Annual Monitoring and Situational Awareness Technical Conference – October 3–4, 2017, Atlanta | Register | Hotel and Travel Information | Presentations from Previous Conferences
- GridSecCon – October 17–20, 2017, St. Paul, MN | Conference Details | **Registration Information Coming Soon**

Webinars

- **NEW** Project 2016-04 – Modifications to PRC-025-1 Webinar – 3:00–4:30 p.m. Eastern, August 16, 2017 | Register
- **NEW** Project 2016-02 – Modifications to CIP Standards: Communication Networks and Transmission Owner Control Center (TOCC) Issues Webinar – 1:00–2:30 p.m. Eastern, August 23, 2017 | Register

Standing Committee Meetings and Conference Calls

- Standards Committee Meeting – 10:00 a.m.–3:00 p.m. Central, September 7, 2017 | Register
- Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee Meetings – September 12–13, 2017, Quebec City, Quebec | Register for OC | Register for PC | Register for CIPC | Hotel Registration

Standard Drafting Team Meetings

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

- Project 2016-02 – Modifications to CIP Standards Conference Call – 11:00 a.m.–1:00 p.m. Eastern, August 18, 2017 | Register
- Project 2016-02 – Modifications to CIP Standards Meeting – August 22–24, 2017, Vancouver, WA | Register

- Enhanced Periodic Review/Standing Review Team - Standards Grading Public Meeting – 9:00 a.m. –Noon Eastern, August 22, 2017, Atlanta, GA | In-person Registration | **Webinar Registration Coming Soon**
- Project 2017-04 – Periodic Review of Interchange Scheduling and Coordination Standards Team Meeting – August 23–24, 2017, Atlanta, GA | Register
- Project 2017-03 – FAC-008-3 Periodic Team Meeting – August 23–24, 2017, Atlanta, GA | Register
- Project 2013-03 – Geomagnetic Disturbance Mitigation Meeting – August 29–31, 2017, Audubon, PA | Register
- Project 2017-02 – Modifications to PER Meeting – August 29–30, 2017, Houston, TX | Register
- **NEW** Project 2017-05 – Periodic Review of NUC-001-3 Meeting – September 12–13, 2017, Washington, D.C.| Register
- **NEW** Project 2016-04 – Modifications to PRC-025-1 Meeting – September 26–28, 2017, Atlanta, GA| Register

ABOUT THE WEEKLY STANDARDS & COMPLIANCE BULLETIN

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

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Guidance Policy

November 5, 2015

RELIABILITY | ACCOUNTABILITY

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Executive Summary

A key factor in the success of compliance monitoring and enforcement of mandatory standards rests on a common understanding between industry and Regional Entities and NERC (ERO Enterprise) Compliance Monitoring and Enforcement Program (CMEP) staff on how compliance can be achieved and demonstrated. For many of NERC's Reliability Standards (standards), this is straightforward. For others, it remains a concern.

In May 2015, a Compliance Guidance Team (Team) was formed by the Member Representatives Committee (MRC), with support from the NERC Board of Trustees (Board), to consider approaches useful in providing guidance for implementing standards, and develop a policy proposal for the purpose, development, use, and maintenance of this guidance.

The Team identified two purposes for guidance: (1) to assist registered entities with the implementation of standards and (2) for the ERO Enterprise to provide direction to ERO Enterprise CMEP staff. The Team also established a set of principles for the development of guidance and is recommending the development of the following:

- Implementation Guidance
- CMEP Practice Guides

Implementation Guidance provides a means for registered entities to develop examples or approaches to illustrate how registered entities could comply with a standard[1] that are vetted by industry and endorsed by the ERO Enterprise. The examples provided in the Implementation Guidance are not exclusive, as there are likely other methods for implementing a standard. The ERO Enterprise's endorsement of an example means the ERO Enterprise CMEP staff will give these examples deference when conducting compliance monitoring activities. Registered entities can rely upon the example and be reasonably assured that compliance requirements will be met with the understanding that compliance determinations depend on facts, circumstances, and system configurations.

CMEP Practice Guides differ from Implementation Guidance in that they address how ERO Enterprise CMEP staff executes compliance monitoring and enforcement activities, rather than examples of how to implement the standard. They are developed and maintained by the ERO Enterprise, although in some cases, the ERO will hold policy discussions with industry stakeholders. CMEP Practice Guides will be posted on the NERC website for transparency.

In order to ensure that all Implementation Guidance and other information related to a standard are easily accessible, the Team is proposing a "one-stop shop" on the NERC website where all guidance and information on a particular standard would be located.

The Team believes the proposed policy will bring multiple benefits to industry, including the development of Implementation Guidance by registered entities, a simple process for sharing endorsed implementation methods, collaboration with other registered entities and the ERO Enterprise, and transparency of Implementation Guidance and CMEP Practice Guides.

[1] Although the term standard is used, Implementation Guidance could also apply to a specific requirement or requirements within the standard.

Introduction

Purpose

A key factor in the success of compliance monitoring and enforcement of mandatory standards rests on a common understanding between industry and ERO Enterprise CMEP staff on how compliance can be achieved and demonstrated. For many standards, this is straightforward. For others, it remains a concern. Moreover, some standards are written deliberately to enable a variety of approaches to compliance as the nature of the desired end-state does not lend itself to singular or clear cut solutions given the range of system configurations and potential responses to achieving the reliability goal.

Since the inception of NERC's CMEP, the ERO Enterprise and registered entities have strived to bring clarity and certainty to all parties through a variety of means, some more successful than others. The starting point for understanding the standard is the plain language of the standard and all of the supporting materials developed in the process leading to the approval of the standard (i.e., technical papers, webinars with drafting team members, FAQs, and Reliability Standard Audit Worksheets (RSAWs)). To the extent that the accompanying documentation answered all participants' questions, nothing further was needed. However, disputes have arisen about the meaning of the words in some standards, leading to requests for clarification or revisions to the standard. To help fill the gap, the ERO has issued a number of supplementary documents over time, including Compliance Application Notices (CANs) and Compliance Application Reports (CARs). However, at times, these documents were perceived by some in industry to change the scope of the standard or provide interpretations to audit staff in areas of ambiguity.

More recently, with the addition of more results-based standards, which inherently allow for greater flexibility by entities in responding to standards and requirements, industry has stepped up with informal best practice guides and other work products to address compliance uncertainty. These range from "good ideas" from one or a few entities, to full-blown collaborative development of guides based on the work of committees of experts under the sponsorship of an organized group, e.g., the North American Transmission Forum (NATF). The role and status of these efforts have been unclear in relation to meeting compliance with standards and CMEP practices.

Also, with the controversy surrounding guidance memorandums issued in relation to CIP Version 5, which were later withdrawn, the ERO proposed developing a policy on compliance guidance to bring order and clarity to these disparate elements. Under the sponsorship of the MRC with support from the Board, the Team was formed and charged with bringing a policy paper to the Board of Trustees by its November 2015 meeting regarding the purpose, development, use, and maintenance of compliance guidance. The mandate for the Team, including its members, is included in **Appendix A**.

Given the above, the Team focused on how to reduce controversial approaches and provide the industry and the ERO Enterprise with additional clarity on implementing standards.

Principles for Compliance Guidance

As a starting point, the Team considered and built upon the principles provided in the April 2, 2015 MRC Informational Session agenda package[2], and established the following principles:

- Guidance documents cannot change the scope or purpose of the requirements of a standard.
- The contents of guidance are not the only way to comply with a standard.

[2] http://www.nerc.com/gov/bot/MRC/Agenda%20Highlights%20nad%20Minutes%202013/MRC_Info_Session_Agenda_Pkg_042015.pdf (*see* Agenda Item 4d)

- Compliance expectations should be made as clear as possible through the standards development process which should minimize the need for guidance after final ballot approval of a standard.
- Forms of guidance should not conflict.
- Guidance should be developed collaboratively and posted on the NERC website for transparency.

Furthermore, the Team agreed upon the following:

- There should be a finite and limited set of guidance tools that are well understood and are organized to facilitate the use and implementation of the guidance.
- All forms of guidance related to the same standard should be coordinated and collected in one location.
- To the extent that guidance does not address all of the issues that arise, consideration should be given to revising the standard in question.
- NERC and the Regional Entities will exercise professional judgement[3] in an objective manner when evaluating all methods or approaches to comply with a standard and maintain processes to ensure its independence with regards to the development of guidance by registered entities.
- As guidance cannot expand the scope or purpose of a standard, there are other methods outside the CMEP process (i.e., feedback loops to the Standards Committee and NERC standards department, discussions with the entity) for addressing risks that are not subject to the standard.

Based on the above principles, the Team identified two purposes for guidance: (1) to assist registered entities with the implementation of standards and (2) for the ERO Enterprise to provide direction to its CMEP staff, and is recommending the development of the following:

- Implementation Guidance
- CMEP Practice Guides

Implementation Guidance provides examples for implementing a standard, while CMEP Practice Guides provide direction to ERO Enterprise CMEP staff on executing compliance and enforcement activities.

[3] For example, ERO Enterprise CMEP staff playing a role in determining whether there was any non-compliance with a standard may have prior experience with the subject matter and specific ways in which compliance was achieved. The ERO Enterprise should have practices which prevent bias, preserve objectivity, in final determinations of scope or compliance within its CMEP activities.

Implementation Guidance

Purpose

Implementation Guidance provides a means for registered entities to develop examples or approaches for ERO Enterprise endorsement to illustrate how registered entities could comply with a standard.

Description

Implementation Guidance is defined as "providing examples or approaches within the range of compliance solutions developed in a transparent and collaborative manner for registered entities to comply with standard requirements. Additionally, documents considered to be Implementation Guidance have gone through a vetting process and are endorsed by the ERO Enterprise."[4]

Implementation Guidance does not prescribe the only approach, but is intended to highlight one or more approaches that would be effective ways to be compliant with the standard. As Implementation Guidance is only meant to provide examples, entities may choose alternative approaches that better fit their situation.

The ERO Enterprise's endorsement means that the ERO Enterprise recognizes the guidance as appropriate for deference during CMEP activities. Deference means that registered entities can rely on the guidance and be reasonably assured that compliance requirements will be met with the understanding that compliance determinations depend on facts, circumstances and system configurations which vary across the interconnections. The ERO Enterprise must respectfully consider applicable guidance in compliance determinations. In the instance that a registered entity, in good faith, relied on guidance, but was found non-compliant with the applicable requirements, the reliance on the guidance will be considered as a significant mitigating factor in any enforcement action by the ERO Enterprise.[5] ERO Enterprise CMEP staff will be informed of Implementation Guidance and ERO Enterprise will direct CMEP staff to consider such guidance as a method to achieve compliance in any applicable compliance determinations. As a registered entity may use other approaches to comply with a standard, ERO Enterprise CMEP staff will be objective when assessing other compliance solutions.

This policy is not intended to apply to operating and reliability guidelines developed by the NERC technical committees (Operating Committee (OC)/Planning Committee (PC)/Critical Infrastructure Protection Committee (CIPC)) outside of Section 11 of the Standard Processes Manual (SPM), unless the operating or reliability guidelines provide examples of how to comply with a standard, in which case the examples must be submitted for endorsement if the technical committee would like them to receive deference.

Development

Implementation Guidance can be initiated and vetted in two different ways:

1. During standards development,[6] the drafting team may identify example(s) of how to comply with a standard[7]
    a. Example(s) posted for industry comment for vetting

[4] Implementation Guidance does not conflict with the interpretation process, as the interpretation process is not intended to address compliance approaches. The Standard Processes Manual states that interpretation requests may be rejected where they request approval of a particular compliance approach.

[5] In the event a registered entity believes that an ERO Enterprise CMEP staff did not appropriately consider Implementation Guidance and thus the registered entity should contact its Regional Entity for further discussion.

[6] The standards development process includes coordination with the ERO Enterprise.

[7] The drafting team can and should reach out to industry for assistance, as needed.

b. Project Management and Oversight Subcommittee (PMOS)[8] liaison and NERC standards developer determine whether to elevate to Implementation Guidance and request ERO Enterprise endorsement

2. After a standard is approved in a final ballot, registered entities may develop examples or approaches and vet them through a pre-qualified organization. Pre-qualified organizations are included in **Appendix B**.

After an example has been vetted[9] through the standards development process or a pre-qualified organization the following general steps are envisioned:

1. Example(s) are submitted via email to NERC[10] with acknowledgement of receipt to submitter
2. Example(s) and contact information for the submitter are posted on the NERC website as submitted within seven days of receipt for transparency
3. Example(s) are submitted to the ERO Enterprise for an endorsement within 45-90 days, unless a reason is provided otherwise. Endorsement is subject to technical soundness and compatibility with the standard language, and the ERO Enterprise leadership will ensure consensus among the Regional Entities. The ERO Enterprise will collaborate with submitter to resolve any questions.
4. Endorsed example(s) are moved from initial posting location to the one-stop shop on the NERC website; example(s) will be removed from the initial posting location on the NERC website if not endorsed
5. Once posted on the NERC website as an endorsed example, leadership at each of the Regional Entities will ensure that the example is given deference during CMEP activities.

When a new version of a standard is drafted, the standard drafting team will review existing Implementation Guidance for the previous version and contact the submitter to verify applicability to the new version.

Recommendations for Existing Documents

The compliance guidance policy is not intended to automatically modify the status of any existing document. The Team recommends a series of actions to reconcile Implementation Guidance with existing documents.

Transition of Existing Documents

Upon Board acceptance of the Compliance Guidance Policy, the Team recommends that the following documents be submitted for ERO Enterprise endorsement:

- Lessons Learned and FAQs developed through the CIP Version 5 transition advisory group
- *NATF CIP-014-1 Requirement R1 Guideline*
- *Determination and Application of Practical Relaying Loadability Ratings, Version 1.0, June 2008* for PRC-023

After Board acceptance of the Compliance Guidance Policy, the Team recommends that the Compliance and Certification Committee (CCC) as the lead, with support from the Standards Committee (SC), jointly review other existing documents to recommend which should transition and be submitted for ERO Enterprise-endorsement for Implementation Guidance. The CCC should submit its initial recommendations to NERC by the end of the first quarter of 2016.

[8] The PMOS is a subcommittee of the Standards Committee that advises and supports standard drafting teams to achieve standard goals specified in the Reliability Standards Development Plan.

[9] Example(s) must be vetted with registered entities that would be affected by the approach.

[10] NERC will establish an email address for the submittal of vetted Implementation Guidance.

Section 11 of the Standard Processes Manual

The high-level processes proposed in this document were developed in the context of the Standard Processes Manual and do not overlap or supersede any of the processes therein, including the development of supporting documents under Section 11. Section 11 documents do not include or require the ERO Enterprise endorsement as described herein, and, therefore, do not carry the deference provided to Implementation Guidance. However, Section 11 remains a viable vehicle for posting supporting documents that do not require ERO endorsement for industry comment.

Under Section 11, the SC verifies that a supporting document was reviewed by stakeholders to verify the accuracy of the technical content, but it is not a technical committee. Therefore, the SC is not included on the pre-qualified list of organizations that may develop examples and submit them to the ERO Enterprise for endorsement. However, the Team believes that Section 11, with slight modification to the language, could serve as a vetting vehicle for Implementation Guidance, in addition to the vetting vehicles described herein, prior to submittal to the ERO for endorsement. Thus, the team recommends that the SC consider whether to modify Section 11 and any associated procedures so it can serve as an additional vetting option for submitting Implementation Guidance, and report to the Board on the SC's decision no later than the May 2016 Board and MRC meetings.

RSAWs and Measures

The Team suggests the CCC and SC, with ERO Enterprise CMEP staff, jointly review measures and RSAWs, specifically whether both are needed or could be condensed into a single document or location.

CMEP Practice Guides

Purpose

CMEP Practice Guides address how CMEP staff executes compliance monitoring and enforcement activities and are not compliance approaches to comply with standards.

Description

CMEP Practice Guides will provide:

- direction to ERO Enterprise CMEP staff on approaches to carry out compliance and enforcement activities, including discretion to be applied, auditing practices, risk assessment techniques, policies to be implemented, particular areas of focus for CMEP activities, and to foster consistency in compliance and enforcement;
- a uniform approach used by ERO Enterprise CMEP staff; and
- transparency to registered entities by being publicly posted.

In the event a CMEP Practice Guide will be used to inform ERO Enterprise staff on how to conduct compliance monitoring and enforcement activities as an interim solution until a standard could be revised, the ERO will hold policy discussions with industry prior to developing the CMEP Practice Guide.

Development

CMEP Practice Guides are developed solely by the ERO Enterprise to reflect the independent, objective professional judgment of ERO Enterprise CMEP staff, and, at times, may be initiated following policy discussions with industry stakeholders. Following development, they are posted for transparency on the NERC website.

The Team recommends that the ERO Enterprise develops a CMEP Practice Guide on providing deference to endorsed Implementation Guidance.

One-Stop Shop for All Standards Related Information

The Team recognized the importance of having all information related to a standard, including Implementation Guidance and CMEP Practice Guides, readily available to industry stakeholders and ERO Enterprise staff. Therefore, the Team is recommending housing all information related to a standard in one location on the NERC website. The Team recommends investigating the current 'Related Information' webpages as the location for this information. The Team suggests that NERC staff discuss the organization of these pages to ensure consistency and update the pages to include links to all related information. The pages should include relevant documents from the Compliance, Standards, Reliability Assessment and Performance Analysis, Critical Infrastructure, and Reliability Risk Management webpages. Further, NERC staff will regularly maintain these web pages to ensure that current documents are included in a reasonable timeframe.

Conclusion

The Team recommends the development of Implementation Guidance and CMEP Practice Guides, as described herein, to promote a common understanding amongst industry and ERO Enterprise CMEP staff of how compliance can be achieved and demonstrated. As designed, these tools fulfill the principles identified by the Team, and differentiate between guidance to industry and instruction to ERO Enterprise CMEP staff.

The Implementation Guidance will provide industry confidence in compliance approaches, as the examples are developed by registered entities and will receive deference during CMEP activities. Therefore, industry can rely upon these examples for compliance, provided they are appropriate for the entity's facts and circumstances and implemented in a quality manner.

The CMEP Practice Guides provide confidence by giving industry visibility into CMEP activities and building consistency across the ERO Enterprise in conducting CMEP activities. Additionally, where these are used to provide specific instruction on the use of discretion until a standard can be revised, the ERO Enterprise will consult with industry in policy discussions prior to their development.

Additionally, the Team recommends:

- The CCC will lead with SC support a joint review of existing documents to submit for ERO Enterprise endorsement;
- An SC review of Section 11 of the SPM to determine whether revisions should be considered;
- The CCC and SC, with ERO Enterprise CMEP staff, conduct a joint review of measures and RSAWs;
- Developing a CMEP Practice Guide on providing deference to endorsed Implementation Guidance; and
- Developing a "one-stop shop" on the NERC website.

The Team believes the proposed policy will bring multiple benefits to industry, including the development of Implementation Guidance driven by registered entities, a simple process for sharing endorsed implementation methods, collaboration with other registered entities and the ERO Enterprise, and transparency of Implementation Guidance and CMEP Practice Guides.

Appendix A - Members Representatives Committee Compliance Guidance Team Mandate, June 2015

Purpose

The purpose of this team is to present a proposal to the Members Representatives Committee (MRC) for the purpose, development, use, and maintenance of compliance guidance. When endorsed by the MRC, the proposal will be presented to the Board for approval and implementation.

Background

Since the inception of the ERO, compliance guidance has been a topic of many discussions. Transparency of guidance documents for compliance has gone from having little information released to industry to being transparent to ensure that compliance monitoring is "open-book." Currently guidance may come from several sources, including "Guidelines and Technical Basis" sections that are part of Reliability Standards, the use of Reliability Standards Audit Worksheets (RSAWs), Lessons Learned and FAQs that support implementation, and through other NERC or industry-led outreach or materials. Other communications have also been tested, such as Bulletins, Compliance Application Notices (CANs) and Compliance Analysis Reports (CARs).

To improve the purpose, development, use and maintenance of compliance guidance and align industry and the ERO Enterprise, the NERC Board of Trustees (Board) sought input regarding the use and format of guidance for implementing standards through the April Policy Input Letter and a discussion led by a panel of industry and ERO Enterprise representatives at the May 2015 MRC meeting. These inputs as well as additional outreach that will be conducted, will inform this proposal. Industry was asked to consider the following principles when responding to the Policy Input Letter and during the discussion at the May meeting. These principles will also be used as a starting point for the team to discuss and build upon as appropriate.

- Compliance expectations should be transparent to industry.
- Guidance documents cannot expand upon the requirements of the Reliability Standard.
- Guidance documents issued by the ERO for auditors must reflect the independent, professional judgment of ERO Compliance and Enforcement staff.
- NERC and the Regional Entities must have the flexibility to apply professional judgement in making compliance and enforcement determinations. In applying professional judgement, NERC and the Regional Entities use professional standards (such as professional auditing standards).

Team Composition

The team is comprised of the following representatives who will conduct outreach to other industry, trade, regional and committee representatives:

ERO Enterprise Executives and Board Members*:

1. Ken Peterson, NERC Board Member and SOTC Chair
2. Douglas Jaeger, NERC Board Vice Chair
3. Mark Lauby, Senior Vice President and Chief Reliability Officer, NERC
4. Dan Skaar, President and CEO, MRO

*Additional support from Janice Case, NERC Board Member and BOTCC Chair

Leadership:

1. Sylvain Clermont, MRC Chair
2. Valerie Agnew, Sr. Director of Reliability Assurance, NERC
3. Kristin Iwanechko, MRC Secretary, NERC

Team Members:

1. Nabil Hitti, MRC Vice Chair
2. Tony Montoya, COO, WAPA
3. Tom Bowe, Executive Director of Reliability and Compliance, PJM
4. Nelson Peeler, VP Transmission System Operations, Duke (Sector 1, IOU)
5. Carol Chinn, Regulatory Compliance Officer, FMPA (Sector 2, State/Municipal Utility)
6. Jason Marshall, Vice President of Corporate and Regulatory Affairs, ACES (Sector 7, Electricity Marketer)
7. Brian Murphy, Standards Committee (SC) Chair
8. Patti Metro, Compliance and Certification Committee (CCC) Chair
9. Steven Noess, Director of Compliance Assurance, NERC
10. Sonia Mendonca, Deputy General Counsel, Vice President of Enforcement, NERC

Deliverables

The team will provide a progress report to the MRC at its August 12, 2015 MRC meeting. The team will present a final proposal to the MRC at the November 4, 2015 meeting and, if endorsed, will present it to the NERC Board at its meeting on November 5, 2015. The final proposal will make recommendations on the purpose, development, use, and maintenance of compliance guidance in respect of the principles. Below is a draft timeline.

August

By August, the team will have developed the basis for the proposal. The team will present a status report at the August MRC meeting.

May 29	Establish team
June 1-June 10	Develop strawman for team meeting
June 12	First team meeting – discuss strawman and basis for proposal

June 15-30	Begin draft proposal
July 8-9	Team meeting to discuss and refine draft proposal
July 11-15	NERC staff finalizes documents for August MRC meeting
July 16	Policy Input Letter issued
August 12	August MRC meeting

November

By November, the team will have received industry comments and will present the final recommendations to the MRC and the NERC Board for endorsement.

August 17-19	Team meeting to consider MRC and Board input
August 20	Post for 21-day comment period (ends September 10) and conduct outreach
Week of September 14	Team meeting to consider comments and modify proposal
September 16-23	Conduct additional outreach as needed
September 23-25	Team finalizes proposal (no meeting; a call if necessary)
September 28- October 5	NERC staff finalizes documents for November MRC/Board meeting (no meeting; a call if necessary)
November 4	November MRC meeting
November 5	November Board meeting

Appendix B - Pre-Qualified Organizations for Submitting Implementation Guidance

Examples proposed for Implementation Guidance must be vetted through one of the following pre-qualified organizations[11] prior to being submitted to the ERO Enterprise for endorsement. In order to be pre-qualified to be added to this list as a potential submitter of Implementation Guidance, an organization must submit a request to the CCC. The list of pre-qualified organizations will be posted and maintained on the NERC website.

1. American Public Power Association (APPA)
2. Canadian Electricity Association (CEA)
3. Edison Electric Institute (EEI)
4. Electricity Consumers Resource Council (ELCON)
5. Electric Power Supply Association (EPSA)
6. ISO/RTO Council
7. Large Public Power Council (LPPC)
8. National Association of Regulatory Utility Commissioners (NARUC)
9. National Rural Electric Cooperative Association (NRECA)
10. North American Generator Forum (NAGF)
11. North American Transmission Forum (NATF)
12. Northwest Public Power Association (NWPPA)
13. Transmission Access Policy Study Group (TAPS)
14. Western Interconnection Compliance Forum (WICF)
15. NERC Planning Committee (PC)
16. NERC Operating Committee (OC)
17. NERC Critical Infrastructure Protection Committee (CIPC)
18. Regional Entity Stakeholder Committees

[11] The Team included organizations that are comprised of stakeholders, have methods to assure technical rigor in the development process, and the ability to vet content through its members.

From:	Guy V. Zito
To:	brian.robinson@utilitysvcs.com
Cc:	Ruida Shu
Subject:	RE: Implementation Guidance Question
Date:	Wednesday, July 19, 2017 4:12:04 PM

Brian,

Looks like you will have to develop another CMEP Imp. Guidance document. In spite of my argument to accept your SAR for a revision to CIP-014- the SC narrowly rejected it. There are a number of people that have been suggesting CMEP Imp. Guidance instead of accepting SARs or RFIs. Very concerning. Now, if the developed CMEP Imp. Guidance isn't accepted by the ERO, the issue the entity pointed out will continue to have the issue.

We don't have a set process but RSC or CC are the ones who would shepard it and post it. We can discuss at the August RSC meeting. That will give me some time to have some discussions internally.

Thanks,

Guy

From: Brian Robinson [mailto:Brian.Robinson@utilitysvcs.com]
Sent: Wednesday, July 19, 2017 10:30 AM
To: Guy V. Zito <gzito@npcc.org>
Cc: Ruida Shu <rshu@npcc.org>
Subject: Implementation Guidance Question

Guy,

I am considering filing an implementation guidance with NERC on MOD-026 and MOD-027 applicability, but once I have it drafted I will need a pre-authorized organization to offer support. Have we developed a process in NPCC to utilize NPCC as the pre-authorized organization? Is RSC involved in that process or is it the CC responsibility (I should probably know this).

Any information would be appreciated.

Thanks,

Brian Robinson
Manager of Technical Services
Utility Services

t: (802) 241-1400
c: (802) 793-7128
f: (866) 214-8632
brian.robinson@utilitysvcs.com

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NPCC, Inc.

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

NPCC Compliance Committee Process for Submitting Implementation Guidance to NERC

1. Overview

1.1. The NPCC Compliance Committee ("CC") is a Regional Entity Stakeholder Committee and is a pre-qualified organization that may vet and submit to NERC examples proposed for Implementation Guidance in accordance with the NERC Compliance Guidance Policy.

1.2. Implementation Guidance is defined in the NERC Compliance Guidance Policy.

1.3. The CC process to develop and vet examples proposed for Implementation Guidance is described in this document

1.4. A flowchart providing and overview of the CC process to develop and vet examples proposed for Implementation Guidance is provided in this document.

2. Submitting Draft Implementation Guidance to the CC

2.1. Any NPCC Registered Entity or other NPCC committee, working group, task force, NPCC Staff, or subcommittee may request that the CC vet an example proposed for Implementation Guidance.

2.2. To request the CC vet an example proposed for Implementation Guidance, the registered entity, NPCC committee, working group, task force, NPCC Staff, or subcommittee shall develop and submit Draft Implementation Guidance to the Chair and Vice-Chair of the CC.

2.3. Once the Draft Implementation Guidance is submitted, the Chair or the Vice-Chair of the CC shall provide the Draft Implementation Guidance to the Reliability Standards Committee (RSC) and CC email distribution lists for comment.

2.4. The Chair of the CC shall include the Draft Implementation Guidance as an agenda item during the next CC meeting.

3. Vetting of Implementation Guidance

3.1. All CC Members, RSC Members, and NPCC staff shall have 30 days to provide written comments on the Draft Implementation Guidance. Written comments shall be provided to the CC, the RSC, and the registered entity that submitted the Draft Implementation Guidance via email.

3.2. If there are no written comments during the 30 days or the written comments are supportive and do not include any substantive recommended changes, the CC shall vote on the Draft Implementation Guidance. The vote should normally occur during the next CC meeting.

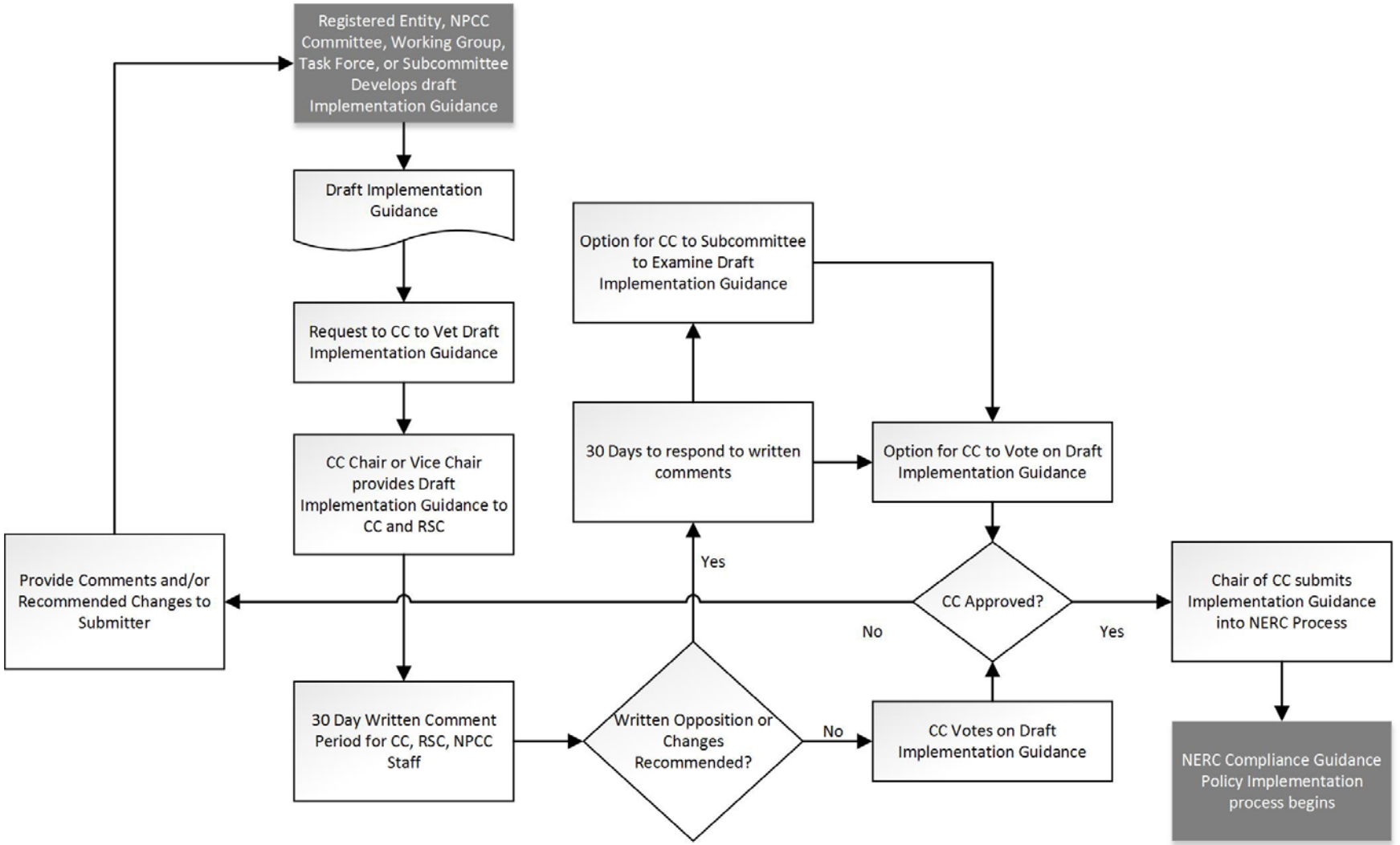
3.3. If there are written comments opposing or recommending substantive changes to the Draft Implementation Guidance, the registered entity, NPCC committee, working group, task force, NPCC Staff, or subcommittee submitting the Draft Implementation Guidance should respond to such comments via email to the CC within 30 days.

3.4. After the time has passed for the submitter to respond to the written comments opposing or recommending substantive changes to the Draft Implementation Guidance, the CC may vote on the Draft Implementation Guidance. The CC may also form a subcommittee to evaluate and report to the CC on the Draft Implementation Guidance.

3.5. If any CC Member company, RSC Member, or NPCC remains opposed to the Draft Implementation Guidance after it has been approved by the CC, such opposition may be documented and provided to the ERO by the party opposed.

3.6. Upon approval by the CC, the Chair of the CC or his designee shall submit the NERC Compliance Guidance Policy Implementation Guidance Submittal Form, the CC approved Implementation Guidance, and any documented opposition to the CC approved Implementation Guidance via email to ComplianceGuidance@nerc.net.

NPCC Compliance Committee Process for Submitting Implementation Guidance to NERC Flowchart Overview



4. References

4.1.1. NERC Compliance Guidance Policy, November 5, 2015

4.1.2. NERC Compliance Guidance Policy Implementation Guidance Submittal Form.

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Registered Entities and ERO Enterprise IT Applications Update

Stan Hoptroff, Vice President, Chief Technology Officer and Director of Information Technology

Standards Oversight and Technology Committee Meeting

August 3, 2017

RELIABILITY | ACCOUNTABILITY

Today's Topics

- Compliance Monitoring and Enforcement Program (CMEP) Technology Project – Program objectives and current activities
- Entity Registration: Coordinated Functional Registrations (CFRs)
- ERO Portal: Misoperations data management
- Public Facing Website
- Electricity Information Sharing and Analysis Center (E-ISAC) Portal Upgrade Update
- Priorities Looking Ahead

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CMEP Technology Project ERO Enterprise Goals and Constraints

- Supports ERO Enterprise Goals
  - Risk Informed CMEP (Goal 2)
  - Reduction of Known Risks to Reliability (Goal 3)
  - Efficiency and Effectiveness (Goal 6)
    - Consistency
    - Productivity
    - Security
- Financial Constraint – Flat, inflationary budgets in the future
- Tactical Constraint – Workload becoming more complex (Critical Infrastructure Protection)

CMEP Technology Project Preliminary Benefits

- Single, common portal for registered entities, enabling consistency of experience
- Real-time access to information, eliminating delays and manual communications
- Improved capability to support the Risk-Based Compliance Oversight Framework
- Enhanced quality assurance and oversight, enabling consistent application of the CMEP
- Improved analytics, including visibility into compliance and reliability risks

CMEP Technology Project Preliminary Benefits

- Increased capability to implement audit best practices and processes
- Standardization and implementation of common business processes and workflows, enabling increased productivity (estimated 15 percent gain for ERO Enterprise CMEP staff)
- Reduced application costs across the ERO Enterprise ($320k annual savings)
- Investment break-even within five years

CMEP Technology Project Options Considered

- Implement common ERO Enterprise solution – supports ERO strategic goals (recommended option)
- Maintain status quo – will not meet future business requirements
- Regions implement individual, new systems of their choosing – more costly than a common system, inconsistent with ERO Enterprise strategic direction

CMEP Technology Project Other Considerations

- Unanimous support from all Regional CEOs for Enterprise option
- Regions deferred investments in lieu of the Enterprise option
- Enterprise option meets strategic goals within constraints

CMEP Technology Program Key Activities in 2017

- Data gathering and development of Business Case
- Technology Leadership Team review
- Webinar completed
- Workshops and requirements validation – August 1-3
- Standards Oversight and Technology Committee (SOTC) Review - August 3

CMEP Technology Program Key Activities in 2017

- Finance and Audit Committee (FAC) 2018 Budget Review - August 9
- August/September/October – Compliance and Certification Committee (CCC), Member Representatives Committee, Business Plan and Budget Input Group Briefings, and other Stakeholder Outreach activities
- Final Business Case Briefings - SOTC, Board of Trustees Compliance Committee (BOTCC), FAC, and Board of Trustees (Board) meetings - October/Nov 2017
- Vendor RFP and selection process – September 3–January 22

Project Financials

- Estimated Capital Investment: $5.1M, completing in 2020
- Estimated Annual Operating Costs: $780k per year
- Estimated average productivity gains for approximately 200 ERO Enterprise staff: ~15 percent in 2022 and beyond
- Estimated point where benefits exceed costs: End of Year 2021

Risk Mitigation and Project Management

- Selected consultant with experience with both the ERO Enterprise and CMEP-type software solutions
- Monthly project financial reviews
- Tollgates at each phase to review status and issues: (Analyze, Design, Develop, Test, Deploy)
- Ongoing financial reporting (FAC quarterly financial reports)
- Periodic updates to other Board Committees (SOTC, BOTCC, CCC)

Entity Registration
Coordinated Functional Registrations

- Benefits
  - Consistent and consolidated processes and terminology
  - Workflow automation for common CFR tasks
  - Provide a common source of record for CFR information to Regions, registered entities, and NERC
  - Improve registered entity visibility of standards changes that impact CFR participants and require updates
  - Enhance Region and NERC CFR oversight capabilities through new reporting and analysis functions

Entity Registration
Coordinated Functional Registrations

- Status
  - Development underway (62 percent complete)
  - Go Live: November 2017

ERO Portal: Misoperations

- Benefits
  - Increase efficiency and improve data quality
  - Reduce corporate risk
  - Increase data visibility
  - Increase security

- Status
  - Development underway (55 percent complete)
  - Go Live: October 2017

NERC Public Website Search Feature Upgrade

- Benefits
  - Search optimization - more relevant results
  - Platform upgrade for stability and continued support from Microsoft
  - More efficient content publishing capability

- Status
  - Requirements and Design complete; environment upgrade underway (overall 27 percent complete)
  - Go Live: September 2017

E-ISAC Portal Upgrade

- Benefits
  - Extensible commercial off-the-shelf content management system
  - Significantly improved user interface and experience
  - Enhanced discoverability with robust search and group collaboration
  - Personalized experience with tagging and content feedback ratings
  - Support for STIX/TAXII data and third party application integrations

- Status
  - Members Executive Committee demo scheduled for late August
  - Go Live: planned for Q4

Priorities Looking Ahead

- CMEP Technology Project
- Entity Registration
- E-ISAC Portal Upgrade

Questions and Answers

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Supply Chain Risk Management

Howard Gugel, Senior Director of Standards and Education

Standards Oversight and Technology Committee Meeting

August 3, 2017

RELIABILITY | ACCOUNTABILITY

Cyber Security Supply Chain Standard

- Background
  - FERC issued Order No. 829 on July 21, 2016
  - Standard must be filed by September 2017
- Status
  - Final ballot ended July 20, 2017
    - CIP-013-1 – 84.2%
    - CIP-005-6 – 88.8%
    - CIP-010-3 – 81.4%
  - Present at August Board of Trustees meeting
  - FERC filing deadline of September 27, 2017

Focus

- High and medium impact BES Cyber Systems
- No requirements for low impact BES Cyber Systems
- NERC committed to addressing risks appropriately
  - Identify best practices
  - Develop guidance resources
  - Support common understanding of compliance obligations

Policy Input Questions

- How should NERC support effective implementation?
- How should NERC evaluate effectiveness of the standards going forward?
- Should NERC continue to review the risks from low impact cyber assets?
- Are there actions NERC should take to address additional potential supply chain risks?

Industry Implementation

- Industry education and outreach on supply chain standards
- Vendor outreach on supply chain standards
- Engage NERC technical committees
- E-ISAC data collection
- Effectiveness survey 18 to 24 months after implementation

Questions and Answers

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards Quarterly Status Report

Howard Gugel, Senior Director of Standards and Education

Standards Oversight and Technology Committee Meeting

August 3, 2017

RELIABILITY | ACCOUNTABILITY

Projects with FERC Directives

- 13 standards related directives in progress

Project 2013-03 Geomagnetic Disturbance Mitigation	4	6/4/2018
Project 2015-09 Establish and Communicate System Operating Limits	2	N/A
Project 2015-10 Single Points of Failure	2	N/A
Project 2016-02 Modifications to CIP Standards (Revisions unrelated to Definition of "Low Impact External Routable Connectivity")	2	N/A
Project 2016-03 Cyber Security Supply Chain Management	1	9/27/2017
Project 2017-06 Modifications to BAL-002	2	N/A

Standards Efficiency Review

- Evaluate the potential scope of the project – 2017 Q3
- Expert team assembled to compile candidate list - 2017 Q4
- Candidate list provided to industry for comment/ballot – 2018 Q1
- Proposed retirements to NERC Board of Trustees – 2018 Q2 or Q3
- Incorporate experience from both p81 and independent expert review panel projects
- Expert team provided information from grading and review projects

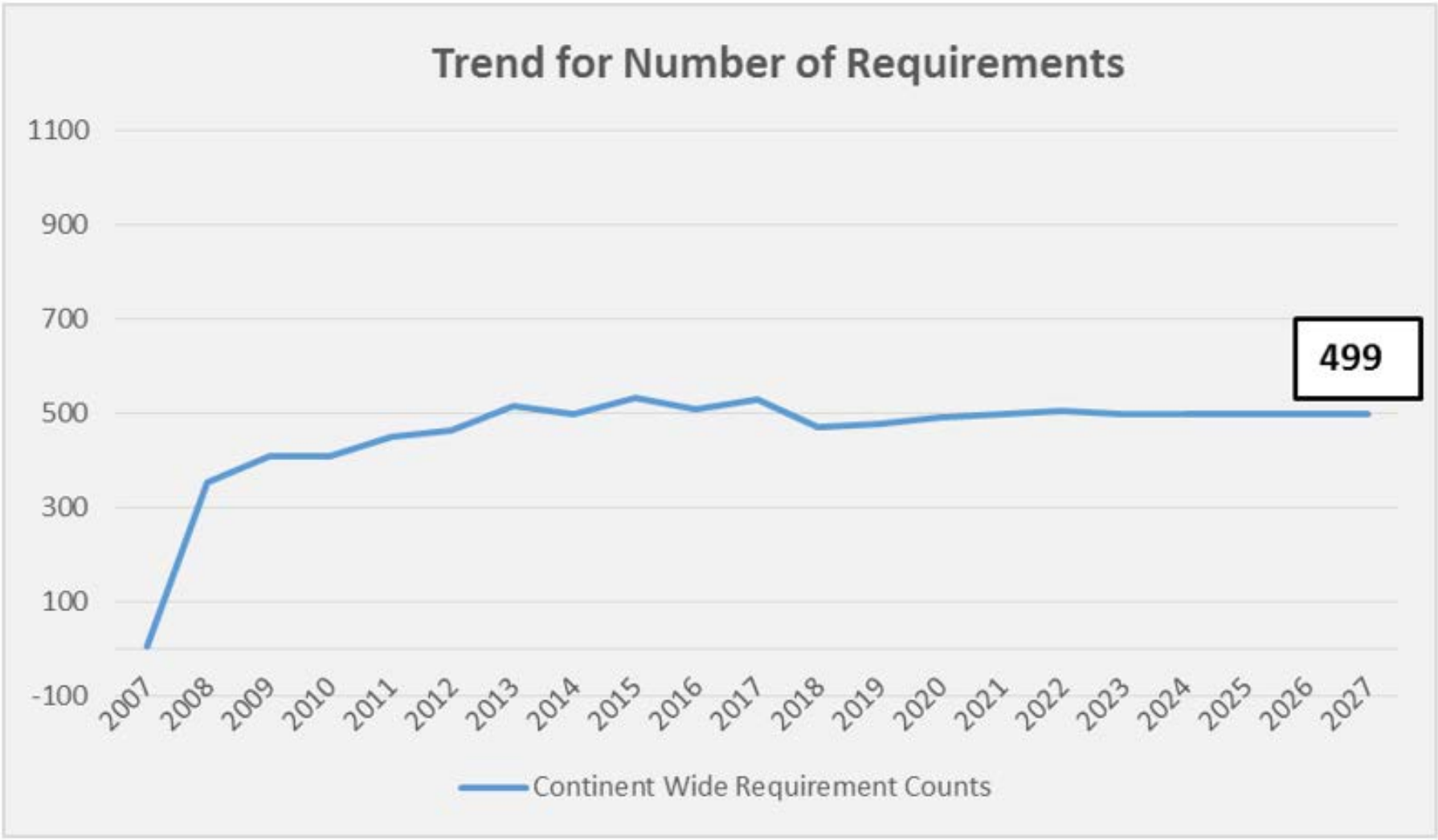
Standard Projections

- August 2017 (1 planned)
- November 2017 (0 planned)
- February 2018 (2 planned)
- May 2018 (3 planned)

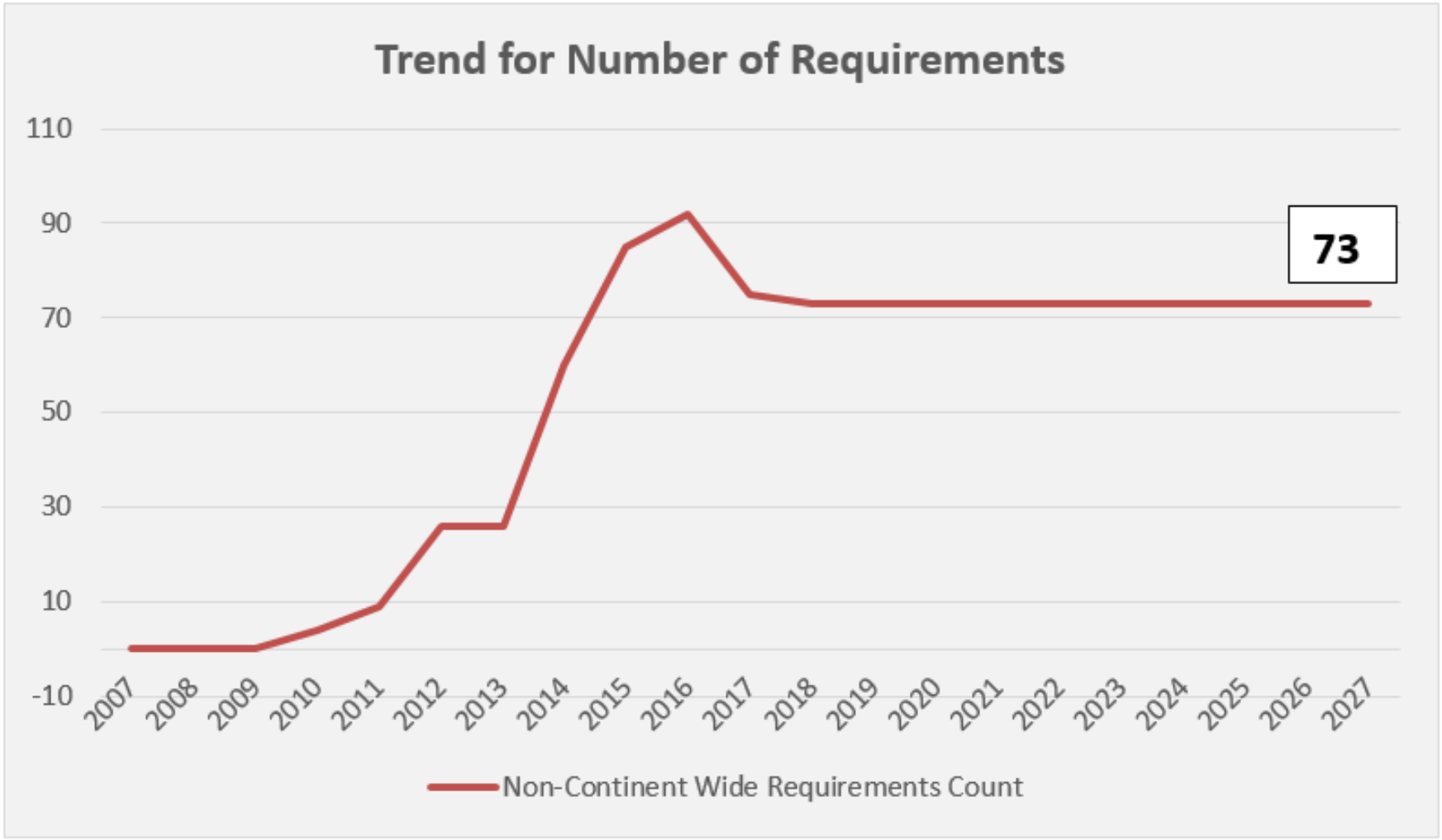
Standards Committee Report

- Reliability Standards Development Plan
  - Anticipated endorsement by Standards Committee: September 2017
  - Presented to Board of Trustees: November 2017
- Supply Chain Reliability Standard success
- Endorsed Standard technical rationale and guidance process
- Initiated three periodic reviews, informed by 2017 grading

Continent-wide Trend



Regional Trend



Questions and Answers

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Official Comment Form
Reliability Guideline: Area Control Error Diversity Interchange Process

Please use this form to submit comments on the proposed Reliability Guideline: Area Control Error Diversity Interchange Process.

Comments must be submitted by 5:00 p.m. ET on August 28, 2017.

You may submit the completed Microsoft Word form by e-mail to (reliabilityguidelinecomments@nerc.net) with the words "Reliability Guideline: Area Control Error Diversity Interchange Process" in the subject line. Only comments submitted in Microsoft Word format using this comment form will be accepted. Red-line document changes, PDF versions of this document, or email comments will *NOT* be accepted.

Comments may be submitted by individuals or groups.

If the comments are from an individual, please provide the contact information for the submitter in Information Table 1, and provide the requested affiliation information in Information Table 2.

If the comments are from a group, please provide the contact information for the leader of the group in Information Table 1, the requested affiliation information in Information Table 2, and a list of all group participants in Information Table 3.

Note: If you need to add a row to the table below please select Table from the above toolbar then Insert "Row Above" or "Row Below."

If you have any questions on the subject information, please contact Stephen.Crutchfield@nerc.net.

Information Table 1 Individual Commenter or Group Leader Contact Information
Name:
Entity Name:
Telephone:
E-mail:

Information Table 2		
Select each NERC Region that you represent:	**Select each Industry Segment that you represent:**	
☐ ERCOT ☐ FRCC ☐ MRO ☐ NPCC ☐ RFC ☐ SERC ☐ SPP ☐ WECC ☐ NA – Not Applicable	☐	1 — Transmission Owners
	☐	2 — RTOs, ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities
	☐	NA – Not Applicable

Information Table 3			
Group Comments (Complete this page if comments are from a group.) **Group Name:**			
Additional Member Name	**Additional Member Entity Name**	**Region(s)**	**Segment(s)**

Enter all comments in the tables below. Red-line changes will not be accepted. Submit this form in Microsoft Word format only.

There are two forms provided for your use to submit comments on this guideline.

The first form is used to provide general comments on the guideline. These general comments should not reference a specific section or page in the guideline, but rather, should be overall comments on the guideline or concepts in the guideline, and may include repeating comments that are applicable to a number of sections.

The second form is used to provide comments to specific sections of the guideline, such as spelling, punctuation or word usage comments, as well as to provide specific comments to concepts on the indicated page and line of the guideline. When performing the review, please use the "clean version (not any "redline" versions) of the document in order to ensure consistently in provided comments from multiple commenters.

Please provide sufficient information in your comments to allow the working group to understand the issue being commented upon, and provide suggested changes to the guideline that the working group may use to update the guideline.

Instructions for general comments:

- Provide a description (or explanation) of your comments in the Comment column.
- Provide a proposed wording (or other) change in the proposed change column. The text in the proposed change column will be used by the working group to update the document.

The last column will be used by the working group during the comment resolution process, and should not be filled out on this comment form.

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Comment	Proposed Change	Comment resolution adopted by the working/task group on each comment submitted

Instructions for specific comments on the text of the document:

- Provide a page number and line number reference for each comment (page and line numbers are provided in the review version of the document). When referencing page and line numbers, refer to the "clean" version of the posted document. Please DO NOT refer to page and line numbers in "redline" versions of documents.
- Identify each comment as either E (editorial), i.e., spelling, punctuation, formatting; or, T (technical) i.e., content changes.
- Provide a description (or explanation) of your comments in the Comment column.
- Provide a proposed wording (or other) change in the proposed change column. The text in the proposed change column will be used by the NERC Operating Committee to update the document.

The last column will be used by the working group during the comment resolution process, and should not be filled out on this comment form.

*Note: If you need to add a row to the table below please select Table from the above toolbar then Insert "Row Above" or "Row Below."

Page Number	Line Number	Type of Comment (Editorial / Technical)	Comment	Proposed Change	Comment resolution adopted by the working / task group on each comment submitted

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline~~:~~

~~Reliability Coordinator – Balancing Authorities – Transmission Operators Communication:~~ Area Control Error Diversity Interchange ~~(ADI) process~~Process

Applicability~~:~~

Balancing Authorities (BAs)
Transmission Operators (TOPs)
Reliability Coordinators (RCs)

Preamble

It is in the public interest for the North American Electric Reliability Corporation (NERC) to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The NERC technical committees–the Operating Committee (OC), the Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC)–are authorized per their charters by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security Guidelines (CIPC). These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry. The objective of this reliability guideline is to distribute key best practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines do not provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation and use of guideline practices is strictly voluntary, the review, revision, and development of a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

Background

Area Control Error Diversity Interchange (ADI) is a process in which participating ~~Balancing Authorities~~BAs exchange information related to their raw ~~Area Control Error~~area control error (ACE) values in order to develop ADI adjustment values to their ACE. ~~-~~When there is a diversity of algebraic ~~sign~~signs among ADI participants' raw ACE, ADI adjustments are applied equally to yield ADI-adjusted ACE values that are closer to zero~~, which~~. This can yield benefits to the participating ~~Balancing Authorities as described below.~~ BAs Fundamentally, ADI is simply exchanging a real-time portion of one BA's ACE for an equal but opposite portion of another BA's ACE, thereby reducing the ACE values of both BAs. ADI is considered by some to be a form of supplemental regulation, and there have been ~~five~~several implementations since its inception in the 1990s~~, of which two~~. Of these, a few have been retired due to ~~Balancing Authority~~BA consolidations. Eastern Interconnection ADI participants consider it to be supplemental regulation~~,~~ while Western Interconnection ADI participants consider it to be an ACE exchange. ~~Balancing Authorities~~BAs participating in ADI cite the following benefits as reasons for their participation:

- Low cost and ease of implementation~~.~~
- Fewer output adjustments that reduce heat rate degradation and "wear and tear" on generating facilities~~.~~
- ~~Improved compliance with NERC CPS2 criterion when using ADI-adjusted ACE.~~
- Reduced regulation requirements while having fewer generators operate out of economic merit order~~.~~

~~There is active debate within the industry as to whether ADI is compatible with current NERC standards. In response to a March 12, 2009 letter to the NERC Operating Committee (OC) from Duke Energy expressing concerns related to ACE Diversity Interchange, the NERC OC directed the NERC Resources Subcommittee (RS) to take the lead in forming an ADI Task Force to address these concerns. The ADI Task Force also includes representation from the Interchange Subcommittee (IS) and the Operating Reliability Subcommittee (ORS) as specified by the NERC OC.~~

~~Purpose~~

~~The purpose of this reliability guideline is to address industry concerns related to the usage of ADI. At a higher level, these have been divided into reliability, administrative, and equity concerns and are addressed below in those terms. ADI interactions with present applicable NERC standards are also addressed below. Emphasis will be placed on compliance with existing NERC standards and reliable operations. Recommendations to address these concerns are provided. Possible areas of improvement will be noted, and an overall assessment will be provided as to whether ADI can be implemented without conflicting with NERC standards or having an adverse impact on interconnection reliability.~~

Relevant Definitions from the NERC Glossary

Relevant definitions that exist presently in the NERC glossary are provided ~~below~~here for convenience. Note that a definition for ADI does not exist within the NERC glossary at this time, ~~and~~but a working definition ~~consistent with the three ADI implementations presently in existence will be~~is provided ~~below.~~in the Basic ADI Operating Concepts section.

- **Area Control Error** ~~– The~~is the instantaneous difference between a ~~Balancing Authority's~~BA's net actual and scheduled interchange~~, taking~~. ACE takes into account the effects of ~~Frequency Bias and~~ frequency bias, correction for meter error, and automatic time error correction (ATEC) if operating in the ATEC mode. ATEC is only applicable to BAs in the Western Interconnection.
- **Inadvertent Interchange Energy** ~~– The~~is the difference between the ~~Balancing Authority's Net Actual Interchange~~BA's net actual interchange (NI_A) and ~~Net Scheduled Interchange.~~net scheduled interchange (NI_S). *[Please note that this an after-the-hour calculation based on actual tie flows and schedules. It is not a real-time value.]*
- **Dynamic Transfer** ~~– The~~is the provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy

services associated with a generator or load out of one ~~Balancing Authority Area~~BA area into another.

- **Dynamic Schedule** ~~– A telemetered reading or value~~is a time-varying energy transfer that is updated in real-time and ~~used~~included in the NI_S term in the same manner as ~~a~~ an interchange schedule in the ~~AGC/~~affected BAs' control ACE ~~equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Dynamic Schedules are commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.~~equations (or alternate control processes).
- **Pseudo-Tie** ~~– A telemetered reading or value~~is a time-varying energy transfer between two BAs that is updated in real-time and ~~used~~included in the NI_A in the same manner as a ~~"virtual"~~ tie line ~~flow~~ in the ~~AGC/~~affected BAs' control ACE ~~equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes. [Pseudo tie relationships are commonly used to move load or jointly owned generation to or from another Balancing Authority Area.]~~equations or alternate control processes.

- **Regulating Reserve** ~~– An~~is an amount of reserve responsive to ~~Automatic Generation Control~~automatic generation control, which is sufficient to provide normal regulating margin.
- **Supplemental Regulation** ~~– A~~**Service** is a method of providing regulation service in which the ~~Balancing Authority~~BA providing the regulation service receives a signal representing all or a portion of the other ~~Balancing Authority's~~BA's ACE.

Basic ADI Operating Concepts

The following working definition was developed and reflects the present three implementations of ADI:

- **ACE Diversity Interchange** ~~– A~~is a frequency~~-~~neutral form of ACE exchange that uses real-time, sub-minute adjustments to the raw ACE values of participating ~~Balancing Authorities that~~ BAs. The adjustments always net to zero and are non-zero individually only when at least one participating ~~Balancing Authority's~~BA's raw ACE value differs in algebraic sign from at least one other participating ~~Balancing Authority's~~BA's raw ACE. ~~-~~Participating ~~Balancing Authorities~~BAs achieve reductions in their generation control and reporting ACE values ~~via Dynamic Transfers of~~by incorporating the ADI adjustments computed by an ACE Diversity Interchange algorithm. A participating BA's ADI adjustment term for each calculating cycle allows a flow that has already occurred on the participating BA's tie-lines to be maintained. It does not affect the tie line meters as an actual amount of energy transfer.

While ADI adjustment allocation methods may differ among the ADI implementations, two key features are that the computed ADI adjustments for all participating ~~Balancing Authorities~~BAs must always have a zero sum (see OP1 below) and the computed ADI adjustment for each participating ~~Balancing Authority~~BA will equal zero in the absence of diversity in algebraic sign of the participating ~~Balancing Authorities'~~BAs' raw ACE.~~-~~ These are distinguishing features of the ADI process.

ADI Implementation Mechanics

~~The ADI process as defined above utilizes dynamic transfers in order to achieve final ACE values of lesser magnitude within the ACE equations of the participating Balancing Authorities. While the three present ADI implementations all use Pseudo-Ties, a similar result can be obtained by using Dynamic Schedules instead of Pseudo-Ties.~~

ADI processes depend on the timely exchange of relevant data~~,~~ and consistent implementation of ADI adjustments in the ~~approximate timeframe~~same time frame of EMS scan rates (e.g., ~~4~~six seconds~~). ~~, or less). While the information exchange processes used for ADI have very high availability, ~~Balancing Authorities~~BAs participating in ADI have backup plans to address failures in data exchange communications.

The ADI processes that exist presently allow for individual ~~Balancing Authorities~~BAs to enable or disable their participation in real-time for local or interconnected reliability concerns~~,~~ and allow for a global enabling or disabling of ADI when appropriate for global reliability concerns.

~~Balancing Authorities~~

BAs participating in ADI communicate with their ~~Transmission Operators~~TOs and ~~Reliability Coordinators~~RCs, often with a consistent set of data being exchanged, to address congestion management problems that might be affected adversely by the continued use of ADI.

Present ADI implementations require that the participating ~~Balancing Authorities~~BAs are electrically contiguous (see OP6 ~~below~~in the Operating Principles Associated with ADI Applications section at the end of this document).

~~Balancing Authorities~~

BAs presently utilizing ADI do not use or acquire transmission ~~reservations~~service for ~~power flows that are allowed to persist at times during~~ the ADI process. ~~–~~The common premise is that ADI ~~will use only unallocated transmission after energy markets of higher priority~~is a net zero flow that would have ~~used their transmission allocations.~~ occurred absent ADI. However, ~~Balancing Authorities~~BAs must have transmission connectivity and have arrangements for transmission to participate in ADI.~~-~~ The ADI process will be disabled in the event that normal or contingent operations require the use of transmission being used for ADI-related power flows. ~~-~~Most often, the inadvertent power flows do not persist for extended periods and would net reasonably close to zero over longer intervals.

In theory, the ADI adjustment for each participating ~~Balancing Authority~~BA should net to zero in the longer term if ACE values are more or less random, normally distributed, and ~~having~~have a mean of zero. Deviations from this basic premise could adversely impact ADI accounting and disrupt inadvertent energy accumulations~~.~~ by creating an imbalance.

Present ADI implementations all track ADI accounting for participants involved with the ~~impact that the ADI process is having on~~. This assures that after the fact settlements made through the use of Interchange accounting does not impact hourly or month-end inadvertent ~~and its cumulative impact in the longer term (e.g., monthly).~~ . Differing methods are in use among the present ADI implementations to address various aspects of managing ~~inadvertent.~~ the ADI adjustments.

End-of-Hour Settlements

Since the summation of ADI adjustments within an ADI group sum to zero, participant accounts could be settled offline or added to the inadvertent interchange accounts of the participants. As a means to settle ADI adjustment accounts between participants, they could modify their NI_A values by treating their integrated hourly ADI adjustments as pseudo-ties, thereby affecting their end-of-hour inadvertent interchange. A similar result can be obtained by using dynamic schedules instead of pseudo-ties. Regardless of which method is used, all participants within an ADI group must use the same method.

Within Hour Assessments

The ADI process as defined above is a process that directly modifies ACE in order to achieve a final value of lesser magnitudes for each participating BA to use in the calculation of CPS1 or BAAL. Since frequency response is measured solely with net actual interchange (NI_A) and frequency, it is necessary to ignore or leave out the ADI adjustment from the NI_A value when evaluating the participant's frequency response. It is also necessary to ignore or leave out the ADI adjustment when calculating balancing area load. *To clarify, the ADI adjustment should not modify the real-time NI_A value for any other purpose other than end of hour Inadvertent Interchange accounting.*

ADI Implementation Mechanics and Controls Summary

- ~~Balancing Authorities~~BAs participating in ADI have backup plans to address failures in data exchange communications.
- Individual ~~Balancing Authorities~~BAs can enable or disable their participation in real-time for local or interconnected reliability concerns.
- Global enabling or disabling of ADI is activated when appropriate for global reliability concerns.
- The ADI process will be disabled in the event that normal or contingent operations require the use of transmission being used for ADI-related power flows.
- The present ADI implementations all have limits on the magnitude of ADI exchanges and are subject to oversight by the ADI program's stakeholders and industry subject matter experts.

~~Industry Concerns Expressed Related To ADI~~

Operating Principles Associated with ADI Applications

The following ~~reliability concerns have been expressed about present and future implementations of ADI:~~

~~R1 – Can system frequency~~operating principles (OP) must be ~~affected adversely~~observed by ~~ADI?~~

~~R2 – Does ADI create congestion management problems?~~

~~R3 – Does the presence of ADI create system modeling difficulties?~~

~~R4 – Does ADI detract from the effectiveness of CPS2, which includes adjustments for ADI, in limiting deviations from net scheduled flow of~~those participating ~~Balancing Authorities?~~in ADI applications:

~~R5 – Will ADI hamper the development of future transmission-based ACE limits?~~

- R6 – Are there sufficient controls in place such that Balancing Authorities, Reliability Coordinators, and Transmission Operators can observe any adverse impacts being caused by ADI?
- R7 – Will ADI obscure DCS measurements such that contingencies will in part be exported without proper attendant monitoring?
- R8 – Will inconsistencies in ADI implementations hamper the ability of Reliability Coordinators to manage their Interconnections?

The following administrative concerns have been expressed:

- A1 – Does ADI cause any inherent conflicts with the assignment of functions among entities described in the industry's reliability functional model?
- A2 – Does ADI complicate computations related to transfer capability?
- A3 – Are transmission service requirements addressed adequately in the presence of ADI?
- A4 – How should transmission reservations be addressed in the presence of ADI?
- A5 – Are inadvertent accounts being managed properly in the presence of ADI?

The following equity concerns have been expressed:

- E1 – Does ADI give unfair advantages to its participants related to CPS2?
- E2 – Does ADI interfere with energy or regulation markets?
- E3 – Are there equity concerns related to inadvertent?
- E4 – Are there inequities within the ADI allocation methodologies related to the size of participating Balancing Authorities?

Discussion of Reliability Concerns and Associated Recommendations

The NERC ADITF has reviewed the reliability concerns stated above, and discussions for each follow below. Operating principles to address these concerns are provided below as well. The operating principles stated below are written with a "needs to" sentence structure. This is to facilitate possible usage as a requirement in a future standard document by conversion of applicable "needs to" statements to "shall" statements.

Concerns related to system frequency (R1) were discussed extensively. The present ADI implementations assure that computed ADI adjustments sum to zero and all have backup plans to maintain a zero sum when communications failures arise, the goal of frequency neutrality for ADI processes is being achieved. Possible second order affects related to some ADI participants' AGC systems responding faster than others were considered as well. As the sign of frequency and raw ACE values are in a constant state of flux, it appears that the faster responding Balancing Authorities are equally likely to help or hurt frequency. Also, given that the ADI participants have incorporated ADI limits with the relatively small magnitudes of ADI adjustments in use (largest limit currently in use is 50 MW), it seems clear that instances of adverse impact on frequency would be negligible. The following operating principles will assist in assuring that system frequency is not affected.

OP1 – The algebraic sum of the ADI adjustments used in participating ~~Balancing Authorities'~~BAs' ACE equations need to be zero so that frequency is not affected~~,~~ with due consideration of ~~-~~different scan rates and data latency. ~~{R1, R8}~~

OP2 – Since ADI is dependent on the successful exchange of ACE-related data, ~~Balancing Authorities~~BAs that participate in ADI need to have an agreed upon backup plan that utilizes a consistent method of validating the integrity of its data exchange process~~,~~ in the event of the loss of communications or data quality. ~~{R1, R8}~~ (For example, the detection of an invalid data exchange due to the loss of communications or data quality will initiate the backup plan within 1 minute~~,~~ with automatic disabling of participation upon detection.)

OP3 – Implementations of ADI need to be reviewed and approved by the NERC Resources Subcommittee and the NERC Operating Reliability Subcommittee ~~prior to deployment~~ in order to verify that the intent of applicable ~~Balancing~~balancing and ~~Transmission~~transmission related ~~Standards~~standards are not compromised by the implementation. ~~{R1, R4, R8, E1}~~

~~The NERC ADI Task Force discussed the possibility of ADI processes affecting transmission systems adversely and causing congestion management problems (R2). In reality, actual power flows differ from scheduled power flows, exclusive of ADI processes. The potential for ADI to impact transmission power flows needs to be considered prior to and during actual operations. Present ADI implementations have developed their own methods to provide information that could be used to address congestion, and ADI is commonly disabled on an anticipatory basis before system conditions evolve in a direction that would impact congestion. The following operating principles will assist in assuring that ADI does not affect transmission and cause congestion management problems.~~

OP4 – ~~Balancing Authorities~~BAs participating in ADI need to continuously assure that their regulation control is not affecting the reliability of the transmission system. ~~{R2, R8}~~

OP5 – ~~Balancing Authorities~~BAs participating in ADI need to develop an appropriate methodology to continuously verify that their regulation control is not affecting the reliability of the transmission system. ~~{R2, R8}~~

OP6 – ~~Balancing Authorities~~BAs need to have transmission connectivity and arrangements for transmission to participate in ADI. ~~-~~ADI needs to be designed to avoid adverse impacts on intermediary ~~Balancing Authorities~~BAs and ~~Transmission Operators.~~ TOs. Additionally, there needs to be an established method by which affected ~~Balancing Authorities, Transmission Operators~~BAs, TOs, and ~~Reliability Coordinators~~RCs can be updated with the real-time ADI adjustments being exchanged so that they can monitor any potential reliability impacts. ~~{R2, R6, R8}~~

OP7 – The implementation of ADI needs to allow participating ~~Balancing Authorities~~BAs to change their participation status in real-time, and the ADI algorithm needs to respond immediately to apply the ADI adjustments in recognition of the status changes. ~~{R2, R6, R8}~~

OP8 – Real-time observability of participation and communication status, raw ACE, ADI adjustments, and ADI-adjusted ACE values need to be available to ~~Balancing Authorities, Transmission Operators~~BAs, TOs, and ~~Reliability Coordinators.~~ RCs. The ADI participants need to share the ADI results with the appropriate ~~Reliability Coordinators~~RCs who can also assess the impacts. ~~{R2, R6, R8}~~

~~With respect to OP5 above, there are some implications that are not obvious. Congestion management tools (such as the Interchange Distribution Calculator (IDC) in the Eastern Interconnection or Unscheduled Flow Mitigation Tool (webSAS) in the Western Interconnection) may be inadequate for modeling ADI, as its expected value in any longer term sense typically equals zero. Note that modeling the most positive and most negative values possible within an ADI process in congestion management applications may contaminate the data base congestion relief efforts (e.g., TLR), as it may falsely assume relief will occur when none is forthcoming if the current value of the ADI being provided is not at a boundary value. ADI assignments commonly vary at a sub-minute periodicity while congestion management tools are typically using an hourly resolution.~~

~~The existence of ADI can present some modeling challenges (R3). Custom studies can be performed in multiple passes using maximum positive and negative ADI adjustments to perform sensitivity analyses. However, the ADI operational experience base indicates that existing methods to address transmission issues and congestion management have been adequate, and the operating principles stated previously should minimize the need for extensive modeling.~~

~~To determine the impact of ADI on CPS2 compliance (R4), various participants in existing ADI applications have performed simulations that indicate they would still be CPS2 compliant if ADI was not in use. Also, as noted in OP3 above the NERC Resources Subcommittee and the Operating Reliability Subcommittee will review and approve the ADI deployment prior to its implementation.~~

~~R5 above questions whether the existence of ADI will cause a conflict in the development of transmission-based ACE limits. The effects of ADI, along with other factors, such as frequency support and inadvertent payback, will need to be considered in any transmission-based ACE limits standard development.~~

~~R6 above raises the question of whether Balancing Authorities, Transmission Operators, and Reliability Coordinators have sufficient real-time information available to assure that ADI does not have an adverse impact on reliability. Present ADI implementations provide a standard real-time data set via data links to Balancing Authorities, Transmission Operators, and Reliability Coordinators that can be used to perform this task. OP6 and OP8 adequately address this concern, and OP7 allows for rapid disabling of ADI should the need arise.~~

~~The potential for ADI adjustments obscuring DCS compliance (R7) was discussed. When all ADI participants are also participating in the same Reserve Sharing Group, ADI adjustments will net to zero and DCS compliance evaluations as a group will be correct. In instances where a Balancing Authority is participating in ADI with the contingent Balancing Authority but is not providing contingency reserve, it~~

may be appropriate to make after-the-fact adjustments to ACE for DCS reporting due to the presence of ADI. Two options can be used to address this concern.

(1) ADI can be turned off during a DCS event, as two ADI implementations do presently, or

(2) When reporting, simply subtract out all ADI adjustments, as if ADI was not delivered.

With the above potential solutions, the ADI impact can be managed successfully. The following operating principle should address DCS concerns related to ADI implementations.

OP9 – When a Balancing Authority is an ADI participant and it experiences a contingency that qualifies as a NERC DCS Reportable Event, and, the other Balancing Authorities participating in ADI do not jointly activate contingency reserve sharing for the resource loss, then ADI needs to be disabled by the contingent Balancing Authority when their contingency occurs, or after-the-fact corrections need to be made to remove the ADI adjustment from ACE to compute DCS recovery. {R7, R8}

R8 questions whether differences among the ADI implementations can hamper the ability to properly monitor interconnected operations. Present ADI implementations are consistent in that they are designed to be frequency neutral, have backup plans for communication failures, and continuously provide ADI information for assessing transmission impact and observability. Their differences are regionally specific and are found mainly in inadvertent accounting practices and in the ADI allocation strategies used. These differences do not affect reliability, and the functional consistency is in place to promote reliable operations. Operating principles 1 through 9 above sufficiently support the proper monitoring of interconnected operations.

Discussion of Administrative Concerns and Associated Recommendations

The NERC ADI Task Force has reviewed the administrative concerns stated above, and discussions for each follow below.

A1 above questions whether ADI processes in some way conflict with the reliability functional model. The ADI Task Force does not believe the ADI process conflicts with the NERC Reliability Functional Model.

The transfer limit calculations (A2) are unaffected by ADI, as the ADI power flows have lowest priority and will be suspended in favor of all other energy and reserve products. Also, transfer limit calculations are not typically sensitive to inadvertent power flows given the typical operational bandwidth in flows experienced when regulation is performed to meet control performance standards.

The need for transmission service and reservations were mentioned in A3 and A4 above. Balancing Authorities need to have transmission connectivity and arrangements for transmission to participate in ADI, as addressed in OP6.

The power flows attributed to ADI adjustments have an expected net value equal to zero over time, but are not predictable in real-time (though they are bounded by ADI limits).

A5 above addresses differences in inadvertent accounting practices. A root source of these differences could be traced to the definition of a pseudo-tie. Historically, pseudo-ties were first used to re-assign operating responsibility of the provision of energy for load and/or generation from one Balancing Authority to another. As load and/or generation being re-assigned occurs at an actual specific physical location with either metering to uniquely measure energy or computations to determine the energy by a rule set, those values inherently need to be included in the actual net interchange portion of inadvertent calculations. (See the second sentence of the pseudo-tie definition provided above.) However, when a pseudo-tie is used for the provision of ADI, there is no physical location and no separate meter. Referring to the definition for inadvertent interchange energy above, the meters for a Balancing Authority participating in ADI fully account for actual net interchange by excluding the supplemental regulation value, thus its inclusion would result in double accounting as part of the actual net interchange. This is the rationale for Northeast Power Coordinating Council ADI participants not adjusting their On-Peak and Off-Peak monthly inadvertent accumulations, as any additional flow related to ADI participation is blended in with the inadvertent caused by interchange deviation, frequency support, meter error, and unilateral inadvertent payback. WECC ADI participants choose to adjust their inadvertent accounts for ADI. So while there are implementation differences, the ADI Task Force in its assessment, did not discover any conflicts with NERC standards. In either instance, the inadvertent accounts of non-participants of ADI are unaffected.

Discussion of Equity Concerns and Associated Recommendations

The review of CPS2 compliance for existing ADI implementations did not point to any abusive practices (R4 and E1 discussion above).

ADI's interaction with energy and regulation markets (E2) was reviewed. Given the OP4 and OP5 practice of disabling ADI, if transmission constraints arise, ADI does not impact energy markets directly. Furthermore, ADI is a real-time tool that takes advantage of ACE diversity and has proven over time that less generation regulation movement may free up additional resources to more fully participate in energy markets (regulating limits for generators are commonly more restrictive than their operating limits).

Equitable treatment as it relates to inadvertent energy was discussed (E3). Inadvertent energy accounts of Balancing Authorities not participating in ADI are unaffected.

Inequities in the ADI allocation process were discussed in E4 above. ADI processes have voluntary participation, and a participant can negotiate assignment methodologies with other participants in the design of the ADI process, provided the above operating principles are respected. Balancing Authorities that are not participating in an ADI process are not affected by the details of ADI assignments.

Conclusions

- Based on operating experience, existing implementations of ADI do not have an adverse impact on the reliability of the Interconnections.
- Existing ADI implementations are consistent with NERC standards, especially BAL-001 and BAL-002, as well as BAL-005 R6, R9, and R10.

- ~~ADI implementation differences are acceptable provided that operating principles 1 through 9 are adhered to.~~
- ~~Operating principles 1 through 9 above would assure that future implementations of ADI will not have an adverse impact on the reliability of the Interconnections.~~
- ~~To assure the reliability of the Interconnections, the Reliability Coordinators need to have the ability to monitor ADI activity and, if necessary, direct suspension of ADI and, subsequently, authorize re-initiation of ADI.~~
- ~~With the exception of the requirement for the sign diversity of ACE values, all requirements and operating principles noted for ADI should apply equally to the provision of supplemental regulation. See Appendix 1.~~
- ~~ADI participants need to be Balancing Authorities having transmission connectivity and arrangements for transmission.~~

~~Recommendations – to be considered in the standard making process~~

- ~~ADI implementations should be allowed to continue.~~
- ~~Operating principles within this reliability guideline should be considered in the development of a relevant standard.~~

~~Appendix 1: Generalizing Operating Principles for Non-ADI Forms of Supplemental Regulation~~

~~Throughout its ADI review process, the ADITF considered whether the operating principles that it developed are unique to ADI, or apply equally to non-ADI forms of supplemental regulation. The ADITF concluded that the above operating principles apply equally to non-ADI forms of supplemental regulation, and the above operating principles are generalized below to reflect that conclusion.~~

~~OP1 – The algebraic sum of the supplemental regulation values used in participating Balancing Authorities' ACE equations need to be zero so that frequency is not affected, with due consideration of different scan rates and data latency,~~

~~OP2 – Since supplemental regulation is dependent on successful exchange of ACE-related data, Balancing Authorities that participate in ADI need to have an agreed upon backup plan that utilizes a consistent method of validating the integrity of its data exchange process, in the event of the loss of communications or data quality. (For example, the detection of an invalid data exchange due to the loss of communications or data quality will initiate the backup plan within 1 minute, with automatic disabling of participation upon detection.)~~

~~OP3 – Implementations of supplemental regulation need to be reviewed and approved by the NERC Resources Subcommittee and the NERC Operating Reliability Subcommittee prior to deployment in order to verify that the intent of applicable Balancing and Transmission related Standards are not compromised by the implementation.~~

~~OP4 – Balancing Authorities participating in supplemental regulation need to continuously assure that their regulation control is not affecting the reliability of the transmission system.~~

~~OP5 – Balancing Authorities participating in supplemental regulation need to develop an appropriate methodology to continuously verify that their regulation control is not affecting the reliability of the transmission system.~~

~~OP6 – Balancing Authorities need to have transmission connectivity and arrangements for transmission to participate in supplemental regulation. The supplemental regulation process needs to be designed to avoid adverse impacts on intermediary Balancing Authorities and Transmission Operators. Additionally, there needs to be an established method by which affected Balancing Authorities, Transmission Operators and Reliability Coordinators can be updated with the real-time supplemental regulation values being exchanged so that they can monitor any potential reliability impacts.~~

~~OP7 – The implementation of supplemental regulation needs to allow participating Balancing Authorities to change their participation status in real-time, and the supplemental regulation algorithm needs to respond immediately to apply the supplemental regulation values in recognition of the status changes.~~

~~OP8 – Real-time observability of participation and communication status, raw ACE, supplemental regulation values, and supplemental regulation adjusted ACE values need to be available to Balancing Authorities, Transmission Operators, and Reliability Coordinators. The participants in supplemental regulation need to share the supplemental regulation values results with the appropriate Reliability Coordinators who can also assess the impacts.~~

~~OP9 – When a Balancing Authority~~OP9 – When a BA participates in supplemental regulation and it experiences a contingency that qualifies as a NERC DCS ~~Reportable Event,~~reportable event and~~,~~ the other ~~Balancing Authorities~~BAs participating in supplemental regulation do not jointly activate contingency reserve sharing for the resource loss, then supplemental regulation needs to be disabled by the contingent ~~Balancing Authority~~BA when their contingency occurs~~, or~~. Alternatively, after-the-fact corrections need to be made to remove the supplemental regulation adjustment from ACE to compute DCS recovery.

OP10 – For purposes of BAL-003 or the calculation of load, the ADI adjustment term must be excluded as it will distort the true values.

OP11 – BAs participating in ADI need to determine a maximum value for capping real-time ADI adjustments and ADI accumulations.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Area Control Error Diversity Interchange Process

Applicability

Balancing Authorities (BAs)
Transmission Operators (TOPs)
Reliability Coordinators (RCs)

Preamble

It is in the public interest for the North American Electric Reliability Corporation (NERC) to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The NERC technical committees–the Operating Committee (OC), the Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC)–are authorized per their charters by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security Guidelines (CIPC). These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry. The objective of this reliability guideline is to distribute key best practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines do not provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation and use of guideline practices is strictly voluntary, the review, revision, and development of a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

Background

Area Control Error Diversity Interchange (ADI) is a process in which participating BAs exchange information related to their raw area control error (ACE) values in order to develop ADI adjustment values to their ACE. When there is a diversity of algebraic signs among ADI participants' raw ACE, ADI adjustments are applied equally to yield ADI-adjusted ACE values that are closer to zero. This can yield benefits to the participating BAs Fundamentally, ADI is simply exchanging a real-time portion of one BA's ACE for an equal but opposite portion of another BA's ACE, thereby reducing the ACE values of both BAs. ADI is considered by some to be a form of supplemental regulation, and there have been several implementations since its inception in the 1990s. Of these, a few have been retired due to BA consolidations. Eastern Interconnection ADI participants consider it to be supplemental regulation while Western Interconnection ADI participants consider it to be an ACE exchange. BAs participating in ADI cite the following benefits as reasons for their participation:

- Low cost and ease of implementation
- Fewer output adjustments that reduce heat rate degradation and "wear and tear" on generating facilities
- Reduced regulation requirements while having fewer generators operate out of economic merit order

Purpose

The purpose of this reliability guideline is to address industry practices related to the usage of ADI.

Relevant Definitions from the NERC Glossary

Relevant definitions that exist presently in the NERC glossary are provided here for convenience. Note that a definition for ADI does not exist within the NERC glossary at this time, but a working definition is provided in the Basic ADI Operating Concepts section.

- **Area Control Error** is the instantaneous difference between a BA's net actual and scheduled interchange. ACE takes into account the effects of frequency bias, correction for meter error, and automatic time error correction (ATEC) if operating in the ATEC mode. ATEC is only applicable to BAs in the Western Interconnection.
- **Inadvertent Interchange Energy** is the difference between the BA's net actual interchange (NI_A) and net scheduled interchange (NI_S). *[Please note that this an after-the-hour calculation based on actual tie flows and schedules. It is not a real-time value.]*
- **Dynamic Transfer** is the provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one BA area into another.
  - **Dynamic Schedule** is a time-varying energy transfer that is updated in real-time and included in the NI_S term in the same manner as an interchange schedule in the affected BAs' control ACE equations (or alternate control processes).
  - **Pseudo-Tie** is a time-varying energy transfer between two BAs that is updated in real-time and included in the NI_A in the same manner as a tie line in the affected BAs' control ACE equations or alternate control processes.
- **Regulating Reserve** is an amount of reserve responsive to automatic generation control, which is sufficient to provide normal regulating margin.
- **Supplemental Regulation Service** is a method of providing regulation service in which the BA providing the regulation service receives a signal representing all or a portion of the other BA's ACE.

Basic ADI Operating Concepts

The following working definition was developed and reflects the present three implementations of ADI:

- **ACE Diversity Interchange** is a frequency-neutral form of ACE exchange that uses real-time, sub-minute adjustments to the raw ACE values of participating BAs. The adjustments always net to zero and are non-zero individually only when at least one participating BA's raw ACE value differs in algebraic sign from at least one other participating BA's raw ACE. Participating BAs achieve reductions in their generation control and reporting ACE values by incorporating the ADI adjustments computed by an ACE Diversity Interchange algorithm. A participating BA's ADI

adjustment term for each calculating cycle allows a flow that has already occurred on the participating BA's tie-lines to be maintained. It does not affect the tie line meters as an actual amount of energy transfer.

While ADI adjustment allocation methods may differ among the ADI implementations, two key features are that the computed ADI adjustments for all participating BAs must always have a zero sum (see OP1 below) and the computed ADI adjustment for each participating BA will equal zero in the absence of diversity in algebraic sign of the participating BAs' raw ACE. These are distinguishing features of the ADI process.

ADI Implementation Mechanics

ADI processes depend on the timely exchange of relevant data and consistent implementation of ADI adjustments in the same time frame of EMS scan rates (e.g., six seconds, or less). While the information exchange processes used for ADI have very high availability, BAs participating in ADI have backup plans to address failures in data exchange communications.

The ADI processes that exist presently allow for individual BAs to enable or disable their participation in real-time for local or interconnected reliability concerns and allow for a global enabling or disabling of ADI when appropriate for global reliability concerns.

BAs participating in ADI communicate with their TOs and RCs, often with a consistent set of data being exchanged, to address congestion management problems that might be affected adversely by the continued use of ADI.

Present ADI implementations require that the participating BAs are electrically contiguous (see OP6 in the Operating Principles Associated with ADI Applications section at the end of this document).

BAs presently utilizing ADI do not use or acquire transmission service for the ADI process. The common premise is that ADI is a net zero flow that would have occurred absent ADI. However, BAs must have transmission connectivity and have arrangements for transmission to participate in ADI. The ADI process will be disabled in the event that normal or contingent operations require the use of transmission being used for ADI-related power flows. Most often, the inadvertent power flows do not persist for extended periods and would net reasonably close to zero over longer intervals.

In theory, the ADI adjustment for each participating BA should net to zero in the longer term if ACE values are more or less random, normally distributed, and have a mean of zero. Deviations from this basic premise could adversely impact ADI accounting and disrupt inadvertent energy accumulations by creating an imbalance.

Present ADI implementations all track ADI accounting for participants involved with the process. This assures that after the fact settlements made through the use of Interchange accounting does not impact hourly or month-end inadvertent. Differing methods are in use among the present ADI implementations to address various aspects of managing the ADI adjustments.

End-of-Hour Settlements

Since the summation of ADI adjustments within an ADI group sum to zero, participant accounts could be settled offline or added to the inadvertent interchange accounts of the participants. As a means to settle ADI adjustment accounts between participants, they could modify their NI_A values by treating their integrated hourly ADI adjustments as pseudo-ties, thereby affecting their end-of-hour inadvertent interchange. A similar result can be obtained by using dynamic schedules instead of pseudo-ties. Regardless of which method is used, all participants within an ADI group must use the same method.

Within Hour Assessments

The ADI process as defined above is a process that directly modifies ACE in order to achieve a final value of lesser magnitudes for each participating BA to use in the calculation of CPS1 or BAAL. Since frequency response is measured solely with net actual interchange (NI_A) and frequency, it is necessary to ignore or leave out the ADI adjustment from the NI_A value when evaluating the participant's frequency response. It is also necessary to ignore or leave out the ADI adjustment when calculating balancing area load. *To clarify, the ADI adjustment should not modify the real-time NI_A value for any other purpose other than end of hour Inadvertent Interchange accounting.*

ADI Implementation Mechanics and Controls Summary

- BAs participating in ADI have backup plans to address failures in data exchange communications.
- Individual BAs can enable or disable their participation in real-time for local or interconnected reliability concerns.
- Global enabling or disabling of ADI is activated when appropriate for global reliability concerns.
- The ADI process will be disabled in the event that normal or contingent operations require the use of transmission being used for ADI-related power flows.
- The present ADI implementations all have limits on the magnitude of ADI exchanges and are subject to oversight by the ADI program's stakeholders and industry subject matter experts.

Operating Principles Associated with ADI Applications

The following operating principles (OP) must be observed by those participating in ADI applications:

OP1 – The algebraic sum of the ADI adjustments used in participating BAs' ACE equations need to be zero so that frequency is not affected with due consideration of different scan rates and data latency.

OP2 – Since ADI is dependent on the successful exchange of ACE-related data, BAs that participate in ADI need to have an agreed upon backup plan that utilizes a consistent method of validating the integrity of its data exchange process in the event of the loss of communications or data quality. (For example, the detection of an invalid data exchange due to the loss of communications or data quality will initiate the backup plan within 1 minute with automatic disabling of participation upon detection.)

OP3 – Implementations of ADI need to be reviewed and approved by the NERC Resources Subcommittee and the NERC Operating Reliability Subcommittee in order to verify that the intent of applicable balancing and transmission related standards are not compromised by the implementation.

OP4 – BAs participating in ADI need to continuously assure that their regulation control is not affecting the reliability of the transmission system.

OP5 – BAs participating in ADI need to develop an appropriate methodology to continuously verify that their regulation control is not affecting the reliability of the transmission system.

OP6 – BAs need to have transmission connectivity and arrangements for transmission to participate in ADI. ADI needs to be designed to avoid adverse impacts on intermediary BAs and TOs. Additionally, there needs to be an established method by which affected BAs, TOs, and RCs can be updated with the real-time ADI adjustments being exchanged so that they can monitor any potential reliability impacts.

OP7 – The implementation of ADI needs to allow participating BAs to change their participation status in real-time, and the ADI algorithm needs to respond immediately to apply the ADI adjustments in recognition of the status changes.

OP8 – Real-time observability of participation and communication status, raw ACE, ADI adjustments, and ADI-adjusted ACE values need to be available to BAs, TOs, and RCs. The ADI participants need to share the ADI results with the appropriate RCs who can also assess the impacts.

OP9 – When a BA participates in supplemental regulation and it experiences a contingency that qualifies as a NERC DCS reportable event and the other BAs participating in supplemental regulation do not jointly activate contingency reserve sharing for the resource loss, then supplemental regulation needs to be disabled by the contingent BA when their contingency occurs. Alternatively, after-the-fact corrections need to be made to remove the supplemental regulation adjustment from ACE to compute DCS recovery.

OP10 – For purposes of BAL-003 or the calculation of load, the ADI adjustment term must be excluded as it will distort the true values.

OP11 – BAs participating in ADI need to determine a maximum value for capping real-time ADI adjustments and ADI accumulations.

TPL-007 Revisions

NERC Standards Project 2013-03 GMD Mitigation

Presentation to the
Regional Standards Committee
August 23-24, 2017

Guy V. Zito

NPCC AVP - Standards

Discussion Items:

- FERC Order 830
- Revisions to TPL-007
- TPL-007-1
- GMD Disturbance Mitigation
- Benchmark GMD Event
- Calculation of the Peak Geoelectric Field
- Thermal Assessments on Transformers
- GMD Vulnerability Assessments
- FERC Directive on the Benchmark
- Data Collecting
- Implementation Plan(s)
- HEMP/EMP

FERC Order 830

•*the Commission **approves Reliability Standard TPL-007-1** as just, reasonable, not unduly discriminatory or preferential and in the public interest. While we recognize that scientific and operational research regarding GMD is ongoing, we believe that the potential threat to the bulk electric system warrants Commission action at this time, including efforts to **conduct critical GMD research and update Reliability Standard TPL-007-1 as appropriate**.*

U.S. Federal Energy Regulatory Commission (FERC)
September 2016

Revisions to TPL-007

- Order No. 830 directs NERC to revise TPL-007 to address Commission concerns
  - Modify the benchmark GMD event definition used for GMD assessments
  - Require entities to collect GMD data for model validation purposes
  - Establish deadlines for Corrective Action Plans (CAPs) and mitigating actions to address identified GMD impacts

- Revisions must be filed by May 2018

TPL-007-1

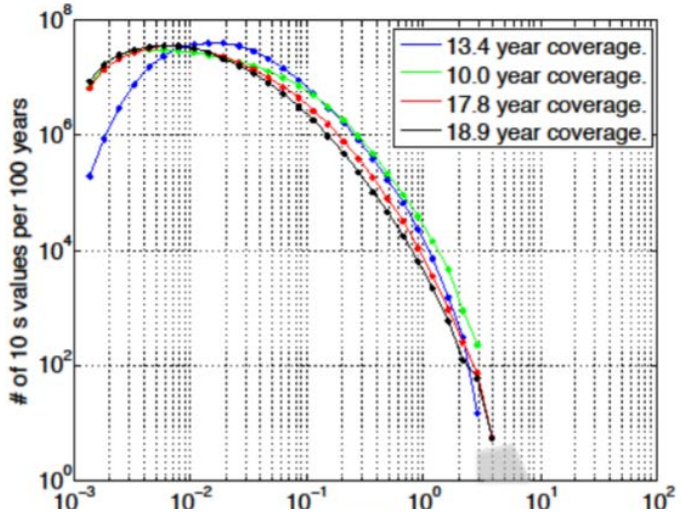
- TPL-007-1 addresses risks of voltage collapse and equipment damage in the Bulk Electric System (BES) caused by GMD events
- Applicable Entities:
  - **Planning Coordinators and Transmission Planners**—perform GIC calculation and network analysis (Vulnerability Assessments)
  - **Transmission Owners**—assess extra high voltage transformers (Wye-grounded on high side, 230kV and higher)
  - **Generator Owners**--assess extra high voltage transformers (Wye-grounded on high side, 230kV and higher)

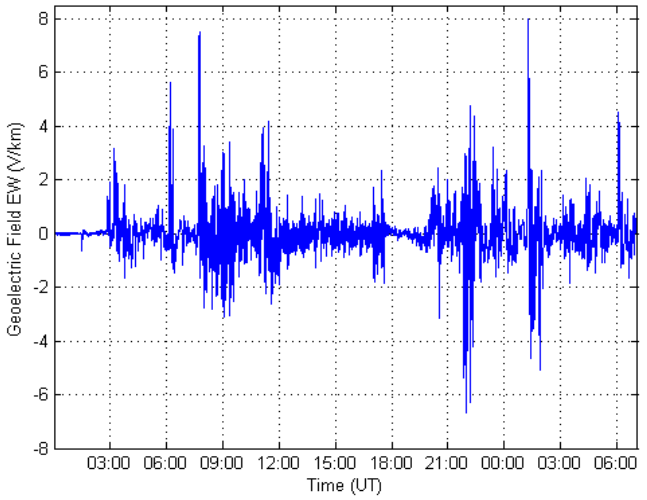
GMD Disturbance Mitigation

- **TPL-007-1**
  - 7 requirements
    - PC and TP identify responsibilities for modeling
    - Maintain the models for GMD
    - Voltage criteria for Benchmark GMD event
    - GMD Vulnerability Assessment every 60 calendar months
    - PC/TP provide GIC flow information to TO and GO
    - TO and GO perform transformer thermal impact assessment on 75 A/Phase applicable BES transformers
    - Develop a CAP if performance doesn't meet Table 1 in the std.
  - Implementation phased in over five year period beginning January 2017 (R1 compliance date: July 1, 2017)

Benchmark GMD Event

- Assessments are based on a severe 1-in-100 year GMD event. Two components for analysis:
  - Amplitude of 8 V/km scaled to the entity's planning area
  - Waveform for assessing transformer hot-spot heating





Calculation of Peak Geoelectric Field

$E_{peak} = 8 \times \alpha \times \beta$ (in V/km)

where,

E_{peak} - Benchmark geoelectric field amplitude at System location

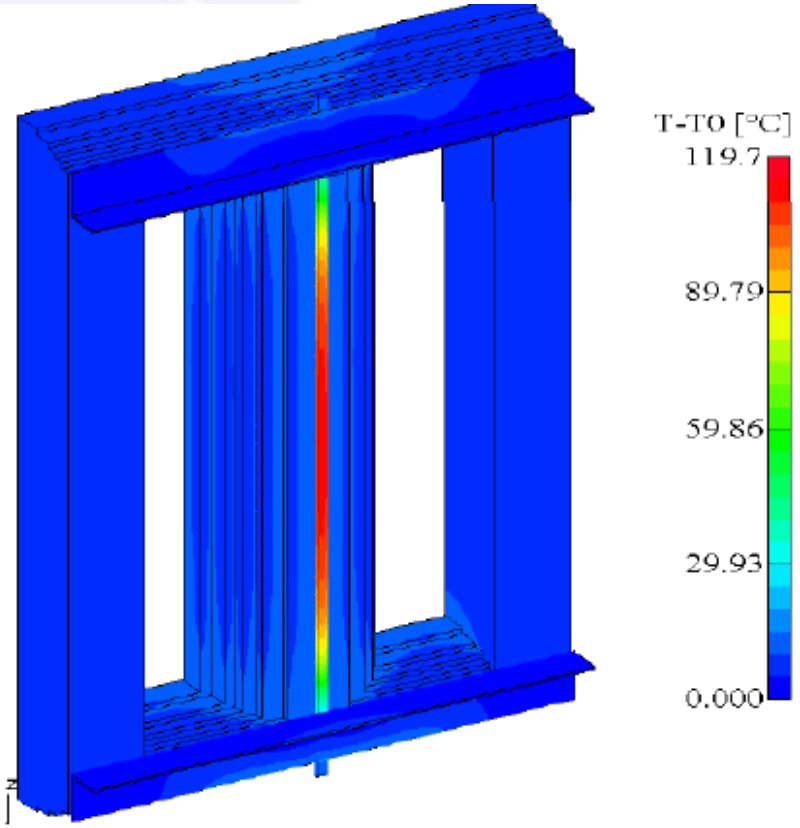
α - Factor adjustment for geomagnetic latitude

β - Factor adjustment for regional Earth conductivity model

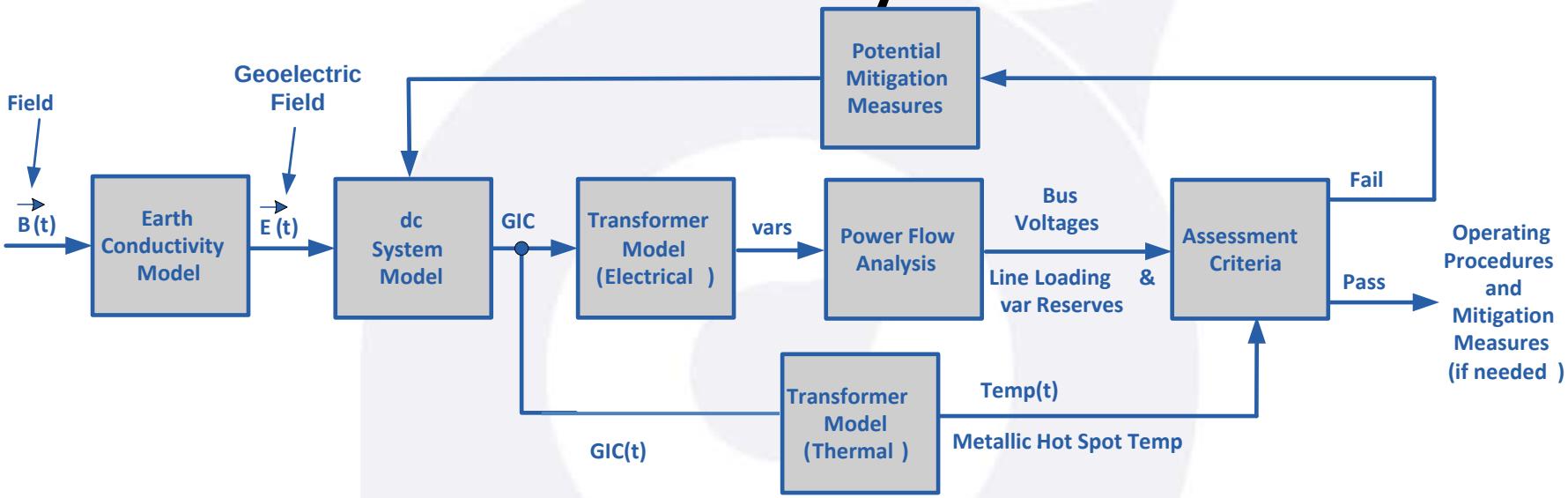
8 V/km is the peak geoelectric field amplitude at reference location (60° N geomagnetic latitude, Quebec resistive ground model)

Thermal Assessments

- R6-TOs and GOs conduct thermal impact assessment of EHV power transformers (Wye grounded on high side at 230kV or higher)
- Techniques:
  - Manufacturer performance curves
  - Thermal response simulation
  - Thermal impact screening
- Assessment is **not required** for transformers < 75 A per phase peak GIC for the Benchmark event



GMD Vulnerability Assessment



- The objective of the GMD vulnerability assessment is to prevent instability, uncontrolled separation, or cascading failure of the System during a GMD event
- System performance is evaluated based on

  System steady-state voltage criteria established by the planning entity

  Cascading and uncontrolled islanding shall not occur

FERC Directive on the GMD Benchmark

- *The Commission approves the reference peak geoelectric field amplitude figure proposed by NERC. In addition, the Commission… directs NERC to develop revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data.*
- -Order No. 830 P 44

Peak Events (Local Enhancements)

- Phenomenon that has been observed and for which the electric field amplitudes are fairly well understood, but the geographical extent is not well known
- Initial review of data from several significant events—Quebec/1989; Greenland/Halloween, 2003; Svalbard, Norway/Halloween, 2003; Alaska/March 2015
  - Waveform similarities—local intense peak (2-5 min in duration)
  - Longitudinal extent: ~300-500km; Latitudinal extent; ~100km
  - Amplitude increase: ~ factor of 2

Supplemental GMD Event

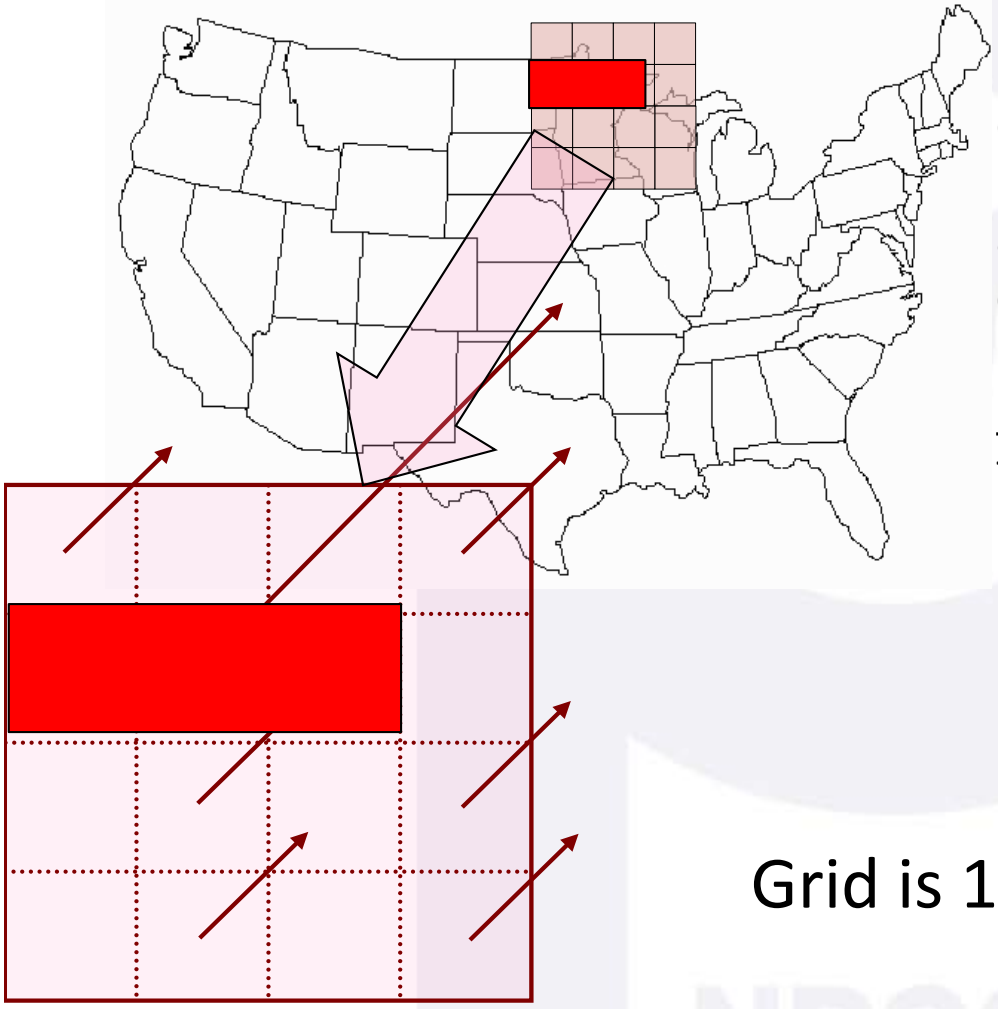
The regional geoelectric field peak amplitude, E_{peak}, to be used in calculating GIC in the GIC system model can be obtained from the reference value of 12 V/km using the following relationship

$$E_{peak} = 12 \times \alpha \times \beta \text{ (V/km)}$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure

Due to the fact that the industry is approaching the boundary of what we know about the science and modeling of Local Enhanced Events, a Corrective Action Plan would NOT be required (like TPL Category D) and the specific methods for applying the supplemental GMD benchmark are left to the planners

Simulation of the Local Enhancement



For illustration purposes, a local enhancement on the order of 100km (lat) by 300km (long) would be applied at 12 V/km in a local area and the GICs calculated.

No Corrective Action Plan required, but the results are to be evaluated for possible mitigating steps

Grid is 100km X 300km

Performing the Supplemental

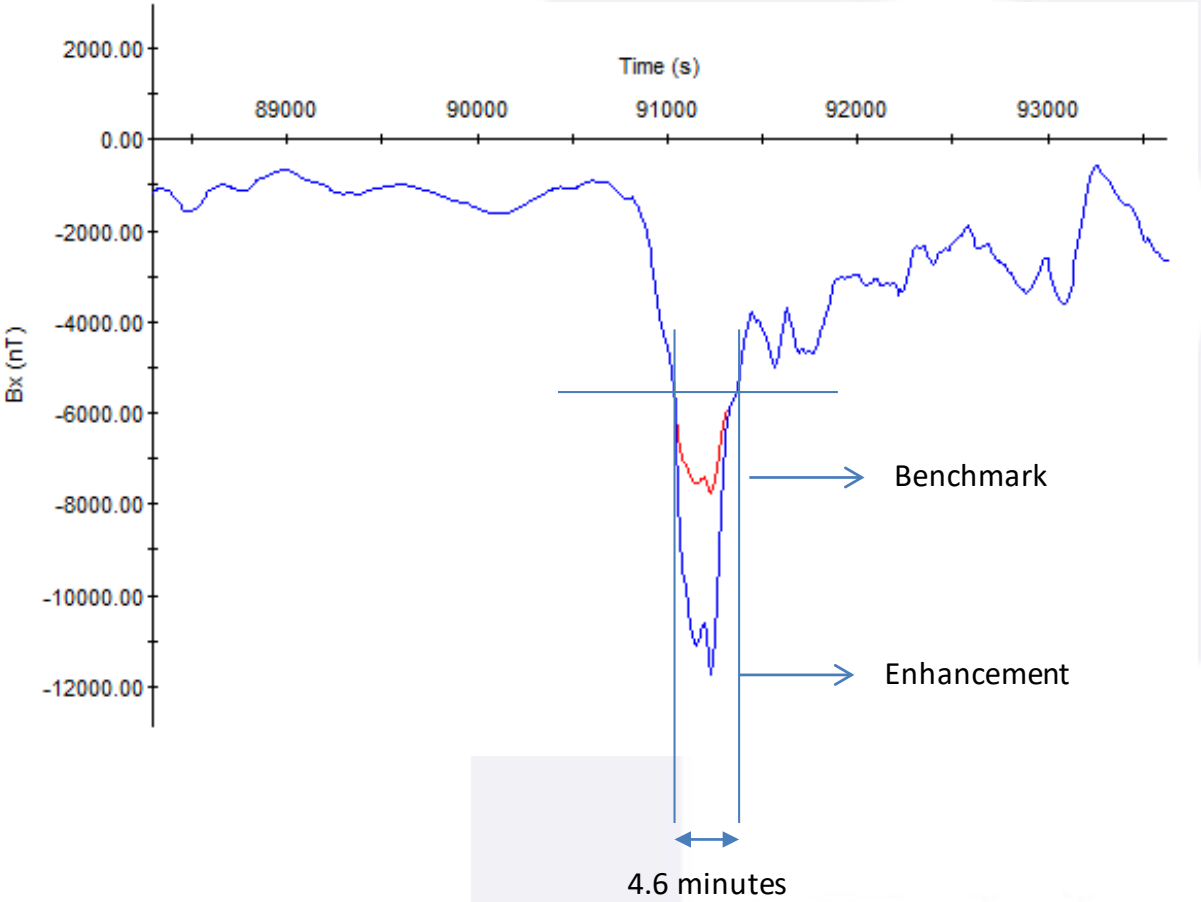
Procedure for planners could be:

- Scaled 12 V/km applied to entire system, or
- Scaled 12 V/km applied to slices of the system ("moving box"), or
- Other methods (e.g. scaled 12 V/km and scaled 8 V/km results compared and incremental reactive power consumption fed into the AC power flow)

Special Note:

- Power flow software vendors are catching up to the need to apply multiple geoelectric fields to the system topology
- More work to be done before this proposal goes forward

Transformer Thermal Assessment



- Scaled 12 V/km used to calculate GIC(t)
- Thermal Screening Criterion would be 85 amperes

If times series analysis is required, then

- Local enhancement synthetically inserted into the benchmark wave shape

Results are informational and left to the asset owner to address, and no Corrective Action Plan is required

CAP Deadlines, FERC Directive

- TPL-007 requires CAP when the GMD Vulnerability Assessment indicate system performance requirements are not met
- Options include
  - Hardening the system
  - Installing monitors
  - Operating procedures
- Order No. 830 directs revisions to establish CAP deadlines (P 101)
  - One year for development of CAP
  - Two years for implementing operating procedure mitigation
  - Four years for implementing hardware mitigation

If the required deadline cannot be met, the implementing entities would be required to report to the Regional Entity and provide basic update reports on an annual basis until completed

Data Collection Directive

The Commission … adopts the NOPR proposal in relevant part and directs NERC to develop revisions to Reliability Standard TPL-007-1 to require responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness, including from any devices that must be added to meet this need. The NERC standard drafting team should address the criteria for collecting GIC monitoring and magnetometer data... and provide registered entities with sufficient guidance in terms of defining the data that must be collected....

-Order No. 830 P 88

New Equipment

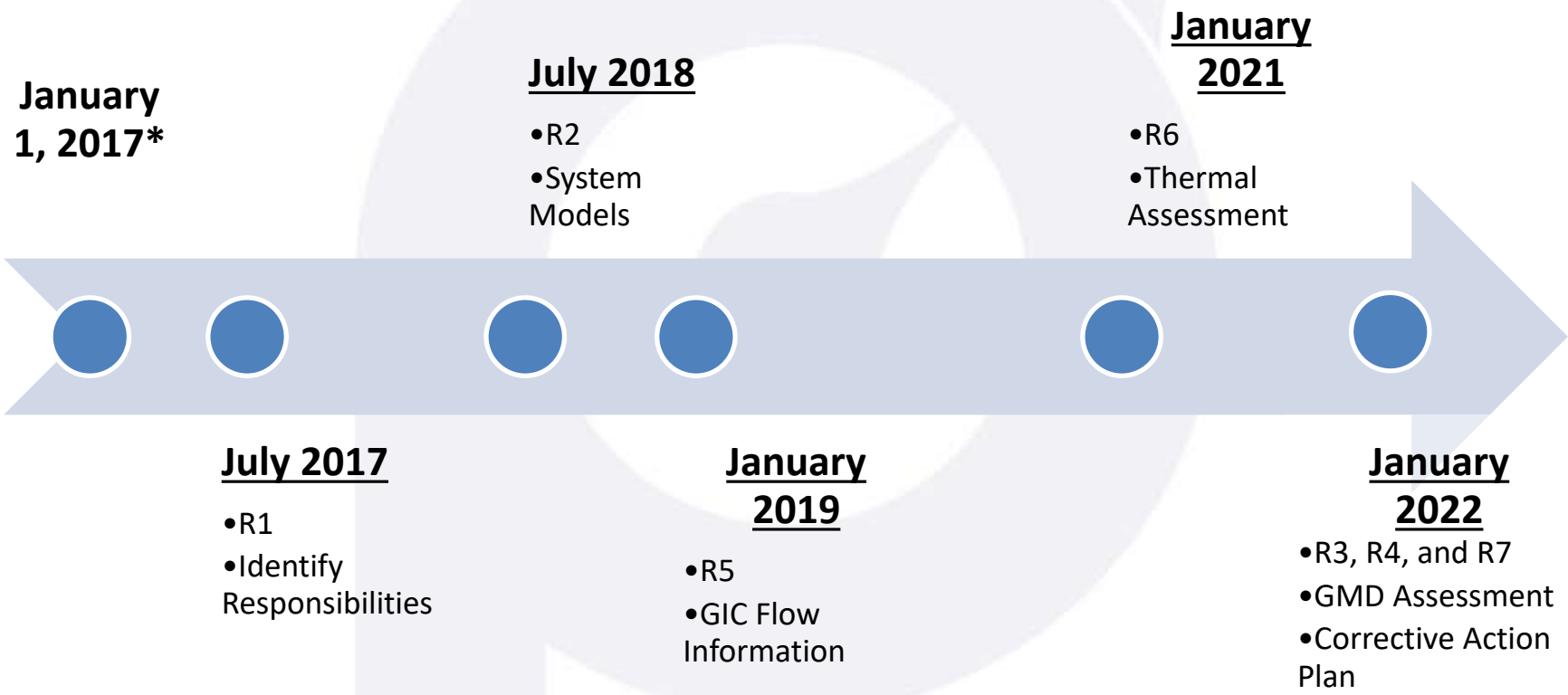
GIC Detectors

- R11 Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one (1) GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model.

Magnetometers

- R12 Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data from at least one (1) magnetometer located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model

TPL-007-1 Implementation Plan



*January 1, 2017 is the first day of the calendar quarter after Order No. 830 becomes effective. For more info see the Implementation Plan posted on the project page.

TPL-007-2

Implementation

- Effective Date before January 1, 2021. Implementation timeline supports applicable entities completing new requirements for supplemental GMD Vulnerability Assessments concurrently with requirements for the benchmark GMD Vulnerability Assessment (concurrent effective dates).
- Effective Date on or after January 1, 2021. Implementation timeline supports applicable entities completing the benchmark GMD Vulnerability Assessments before new requirements for supplemental GMD Vulnerability Assessments become effective.
- For more info see the Implementation Plan posted on the project page.

Ballot

- Initial Ballot conducted August 2-11, 2017
- Formal Comments accepted through August 11, 2017
- SDT will meet at PJM August 29-31, 2017 to address comments, revise standard(?)
- NERC BOT approval on or before the May 2018
- File with the Commission and Provincial Governmental Authorities in May 2018 after BOT approvals

EMP/HEMP

Electromagnetic Pulse (EMP)

EMP refers to a very intense pulse of electromagnetic energy, typically caused by detonation of a nuclear or other high-energy explosive device.

HEMP is an EMP detonated at high altitude to produce more widespread effects (an EMP, as opposed to a HEMP, can cause more localized but still significant impacts).

EMP/HEMP

Starfish Prime (July 1962 EMP Test)

- 900 miles from Hawaii – altitude of 250 miles
  - Effects
  1. Streetlights
  2. Telephone Company Microwave Links
  3. Burglar Alarms
  4. Disabled Automobiles
  5. Limited to the physical horizon of Earth-ground based 62 miles, HEMP thousands of miles

EMP/HEMP

Three Components of a HEMP Event

E1-brief, yet highly energetic, electromagnetic field that may induce extremely high voltages as it couples with electrically conductive structures. The E1 component would be responsible for the most damage to the power grid.

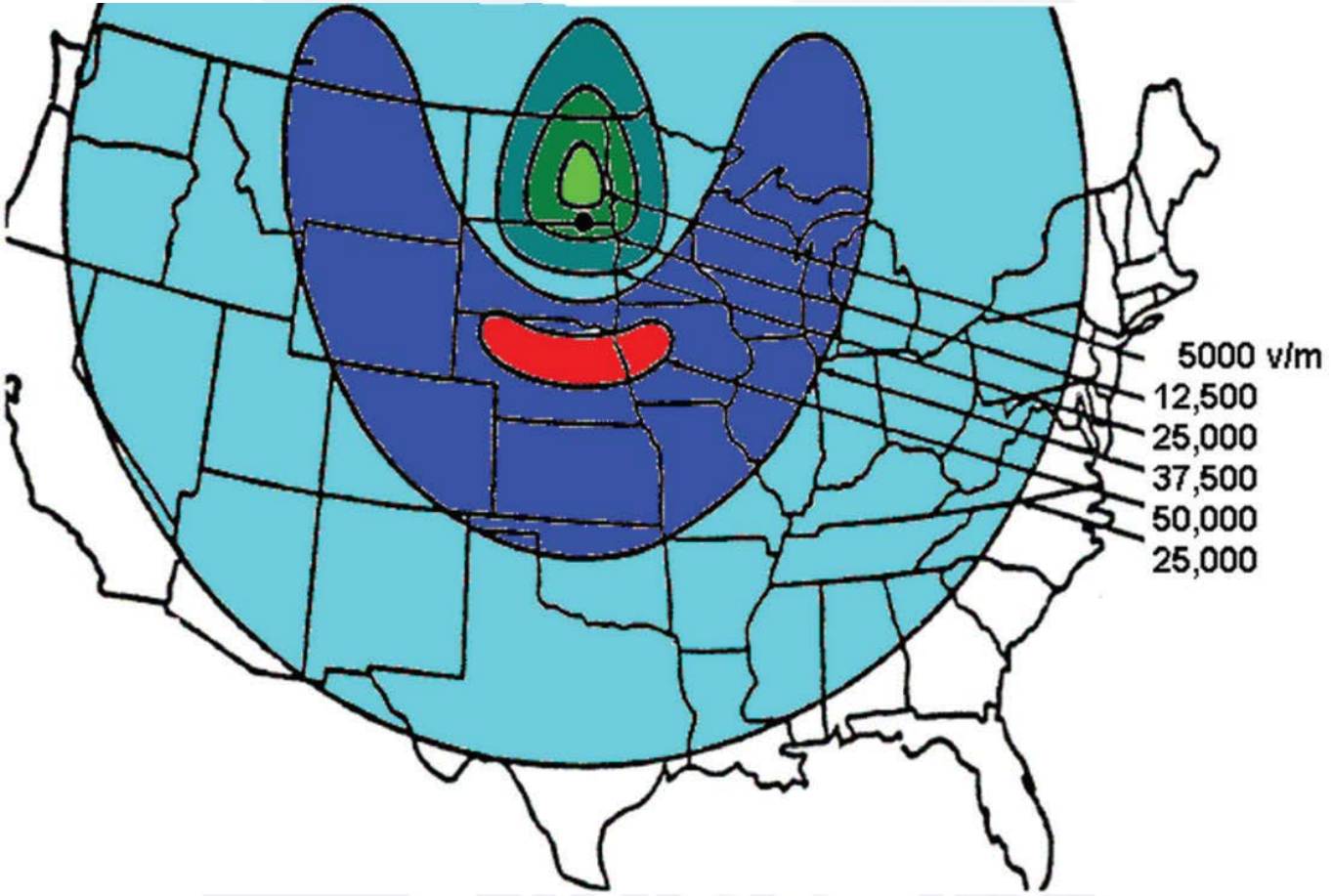
E2-scattered gammas (secondary gammas) and by "neutron scatter gammas" from gammas created when the neutrons produced by the nuclear weapon are scattered by air. The E2 pulse is similar to a conventional lightning strike, beginning approximately a few microseconds to one full second after the onset of the E1 pulse.

E3-The E3 component is similar to GMDs. The E3 results from perturbations of Earth's magnetic field produced by the detonation blast wave. The E3 component, lasting from tens of seconds to minutes in duration, has the potential to impact the operation of power grid transformers, relays,

and related control and processing electronics.

EMP/HEMP

Wave Pattern of HEMP E1 Pulse

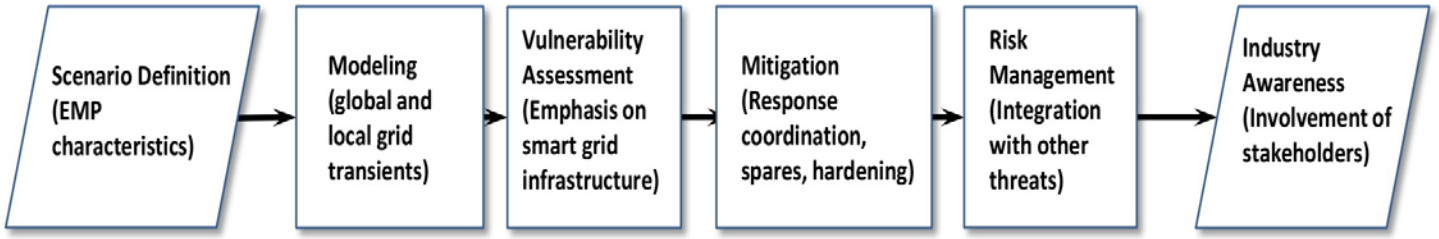


EMP/HEMP

Power Grid Hardening and Mitigation

- HEMP shielding around control facilities
- Standby, Backup Power Generation and Transformer Deployment
- Stored and Shared Spare Components
- Filters and Blocking Devices

Potential Next Steps-



Questions or Comments ?

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events

2. **Number:** TPL-007-~~1~~2

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.2 Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.3 Transmission Owner who owns a Facility or Facilities specified in 4.2;

   4.1.4 Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

5. **Background:**

   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

6. **Effective Date:**

   See Implementation Plan for TPL-007-~~1~~2

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models ~~and~~, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~, and implementing process(es) to obtain GMD measurement data as specified in this standard. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models ~~and~~,

performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~, and implementing process(es) to obtain GMD ~~M~~measurement ~~D~~data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~.

R3. Each 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~~events described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) ~~within 90 calendar days of completion~~ to the responsible entity's Reliability Coordinator,

adjacent Planning Coordinators, and adjacent Transmission Planners~~,~~ within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, ~~within 90 calendar days of completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and to any functional entity who has submitted a written request and has a reliability-related need~~ as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the ~~transformer~~benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power

transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective benchmark GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- **6.1.** Be based on the effective GIC flow information provided in Requirement R5;
- **6.2.** Document assumptions used in the analysis;
- **6.3.** Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and
- **6.4.** Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

Rationale for Requirement R7: The proposed requirement addresses directives in Order No. 830 for establishing Corrective Action Plan (CAP) deadlines associated with GMD Vulnerability Assessments. In Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P. 101). Furthermore, FERC directed establishment of implementation deadlines after the completion of the CAP as follows (P. 102):

- Two years for non-hardware mitigation; and

- Four years for hardware mitigation.

The objective of Part 7.4 is to provide awareness to potentially impacted entities when implementation of planned mitigation is not achievable within the deadlines established in Part 7.3.

R7. Each responsible entity, as determined in Requirement R1, that concludes~~,~~ through the benchmark GMD Vulnerability Assessment conducted in Requirement R4~~,~~ that their System does not meet the performance requirements ~~of~~for the steady state planning benchmark GMD event contained in Table 1 shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The ~~Corrective Action Plan~~CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

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

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or ~~Special Protection Systems~~Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the ~~Corrective Action Plan~~CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. ~~Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1.~~Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to revision by the responsible entity in Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be revised if situations beyond the control of the responsible entity determined in Requirement R1 prevent implementation of the CAP within the timetable for implementation provided in Part 7.3. The revised CAP shall document the following, and be updated at least once every 12 calendar months until implemented:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1;

7.4.2. Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and

7.4.3. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable, and the updated timetable for implementing the selected actions.

~~7.2.~~7.5. Be provided: (i) ~~within 90 calendar days of completion~~development or ~~revision~~ to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the ~~Corrective Action Plan~~CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

~~7.2.1.~~7.5.1. If a recipient of the ~~Corrective Action Plan~~CAP provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements ~~of~~ for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its ~~Corrective Action Plan~~CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its ~~Corrective Action Plan~~CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later,~~within 90 calendar days of its completion~~development or revision to its Reliability Coordinator, ~~adjacent Planning Coordinator(s), adjacent Transmission Planner(s), a functional entity referenced in the Corrective Action Plan~~CAP, ~~and any functional entity that submits~~who ~~has submitted a written request and has a reliability-related need,~~ as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date,

that it has provided a documented response to comments received on its ~~Corrective Action Plan~~CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Supplemental GMD Vulnerability Assessment(s)

Rationale for Requirements R8 - R10: The proposed requirements address directives in Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (P.44, P47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2 The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

8.3 If the analysis concludes there is Cascading caused by the supplemental GMD event described in Attachment 1, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

8.4 The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

8.4.1 If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity

shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective supplemental GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal

receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

GMD Measurement Data Processes

Rationale for Requirements R11 and R12: The proposed requirements address directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness (P. 88; P. 90-92). See the Guidelines and Technical Basis section of this standard for technical information.

The objective of Requirement R11 is for entities to obtain GIC data for the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 6 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System* (NERC 2012 GMD Report). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the transformer and measure dc current flowing through the neutral.

The objective of Requirement R12 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments.

Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:

- Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities.
- Installed magnetometers
- Commercial or third-party sources of geomagnetic field data

Geomagnetic field data for a Planning Coordinator's planning area is obtained from one or more of the above data sources located in the Planning Coordinator's planning area, or by obtaining a geomagnetic field data product for the Planning Coordinator's planning area from a government or research organization. The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator's planning area.

~~R8.~~R11. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R11.

~~R9.~~R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R12.

Table 1 – Steady State Planning GMD Event

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.

b. Generation loss is acceptable as a consequence of the steady state planning GMD events.

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

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
Benchmark GMD Event - GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]
Supplemental GMD Event - GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes	Yes

Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the benchmark and supplemental planning ~~event~~events are described in Attachment 1~~ (Benchmark GMD Event).~~.
3. Load loss as a result of manual or automatic Load shedding (e.g.~~,~~, UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD EventEvents

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshapewaveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.[2]

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 12 V/km for the supplemental GMD event (2) using the following relationships:

$$E_{peak} = 8 \times \alpha \times \beta\beta_{\,b} \text{ (V/km)} \quad (1)$$

$$E_{peak} = 12 \times \alpha \times \beta_{\,s} \text{ (V/km)} \quad (2)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure. Subscripts *b* and *s* for the β scaling factor denotes association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD event isevents are defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \quad (2)$$

[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation projectRelated Information page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx for TPL-007-1:; http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

[2] The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the sSupplemental GMD eEvent dDescription white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \quad (3)$$

where L is the geomagnetic latitude in degrees and 0.1 ≤ α ≤ 1.

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

Table 2– Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events

Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either:

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[3] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (2 3) or Table 2, β is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment Assessments. When a ground conductivity model is not

[3] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[4] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$\beta_b = E/8$~~$\beta = E/8$~~ for the benchmark GMD event (4)

$\beta_s = E/12$ for the supplemental GMD event (5)

where *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.[5] Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (12 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (12 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

[4] Available at http://geomag.usgs.gov/conductivity/

[5] See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

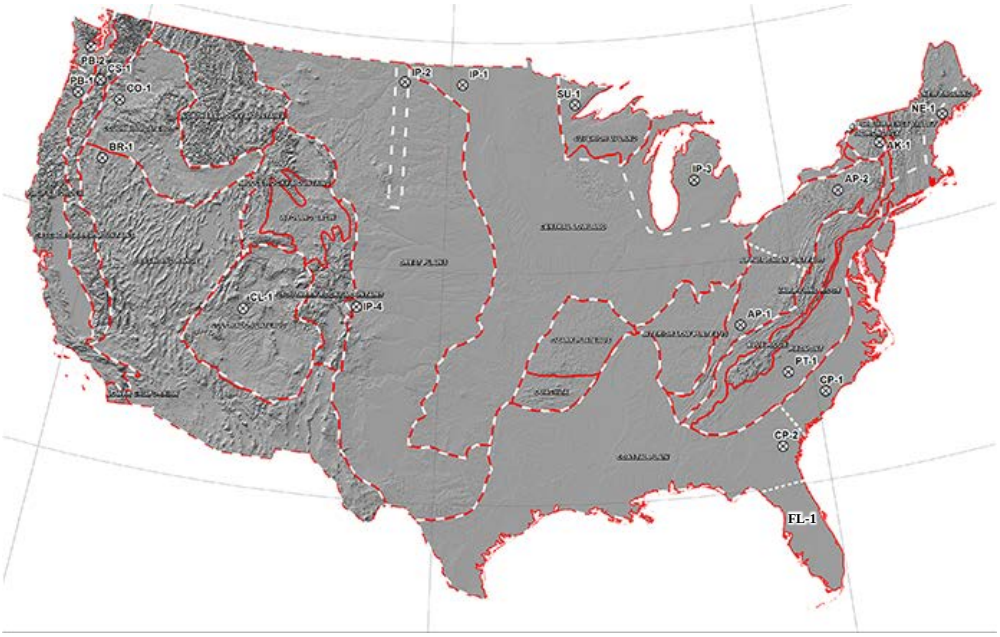


Figure 1: Physiographic Regions of the Continental United States[6]

Figure 2: Physiographic Regions of Canada

6 Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

Table 3 – Geoelectric Field Scaling Factors		
~~USGS~~ Earth model	Scaling Factor ~~(β)~~Benchmark Event (β_b)	Scaling Factor Supplemental Event (β_s)
AK1A	0.56	0.51
AK1B	0.56	0.51
AP1	0.33	0.30
AP2	0.82	0.78
BR1	0.22	0.22
CL1	0.76	0.73
CO1	0.27	0.25
CP1	0.81	0.77
CP2	0.95	0.86
FL1	0.~~74~~76	0.73
CS1	0.41	0.37
IP1	0.94	0.90
IP2	0.28	0.25
IP3	0.93	0.90
IP4	0.41	0.35
NE1	0.81	0.77
PB1	0.62	0.55
PB2	0.46	0.39
PT1	1.17	1.19
SL1	0.53	0.49
SU1	0.93	0.90
BOU	0.28	0.24
FBK	0.56	0.56
PRU	0.21	0.22
BC	0.67	0.62
PRAIRIES	0.96	0.88
SHIELD	1.0	1.0
ATLANTIC	0.79	0.76

Rationale: Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.

The scaling factor associated with the benchmark GMD event for the Florida earth model (FL-1) has been updated based on the earth model published on the USGS public website.

Table 4 – Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or ~~Waveshape~~[7]Waveform for the Benchmark GMD Event[8]

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory is the basis for the reference geomagnetic field ~~waveshape~~waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The ~~Sampling~~ sampling rate for the geomagnetic field ~~waveshape~~waveform is 10 seconds.[9] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor ~~β~~.β_b.

~~[7] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx~~

[8] Refer to the Benchmark GMD Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

[9] The data file of the benchmark geomagnetic field ~~waveshape~~waveform is available on the ~~NERC GMD Task Force project~~Related Information page~~: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx~~ for TPL-007-1: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

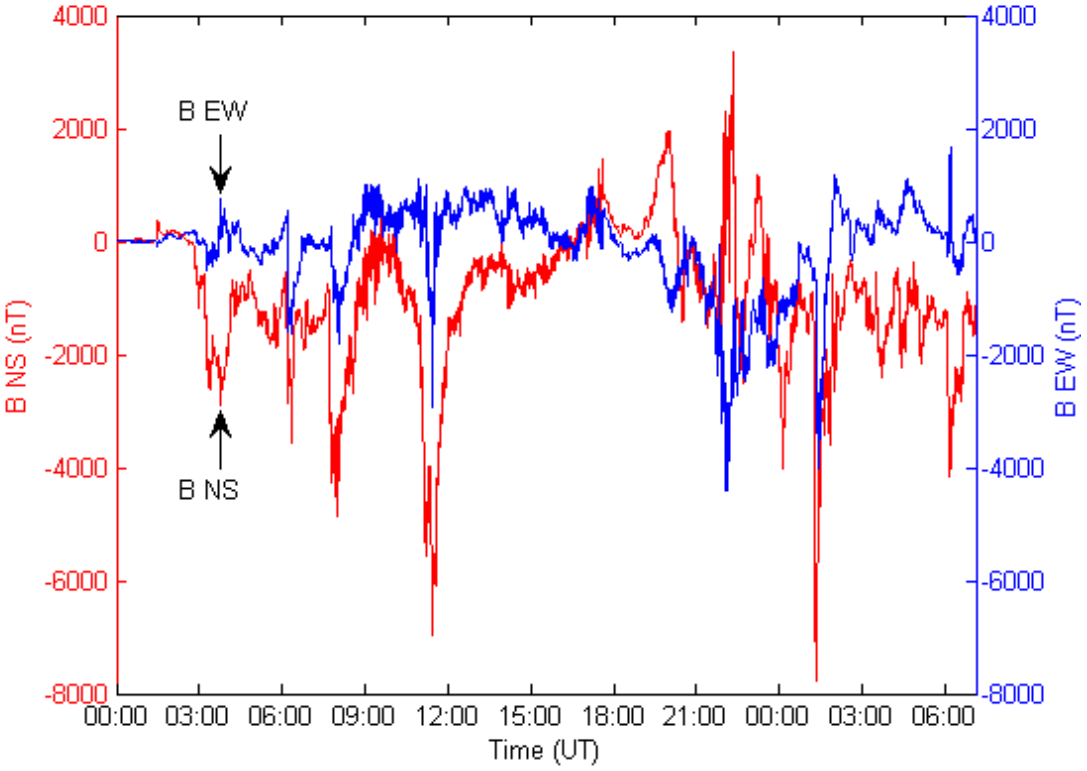


Figure 3: Benchmark Geomagnetic Field ~~Waveshape~~Waveform. Red B_n (Northward), Blue B_e (Eastward)

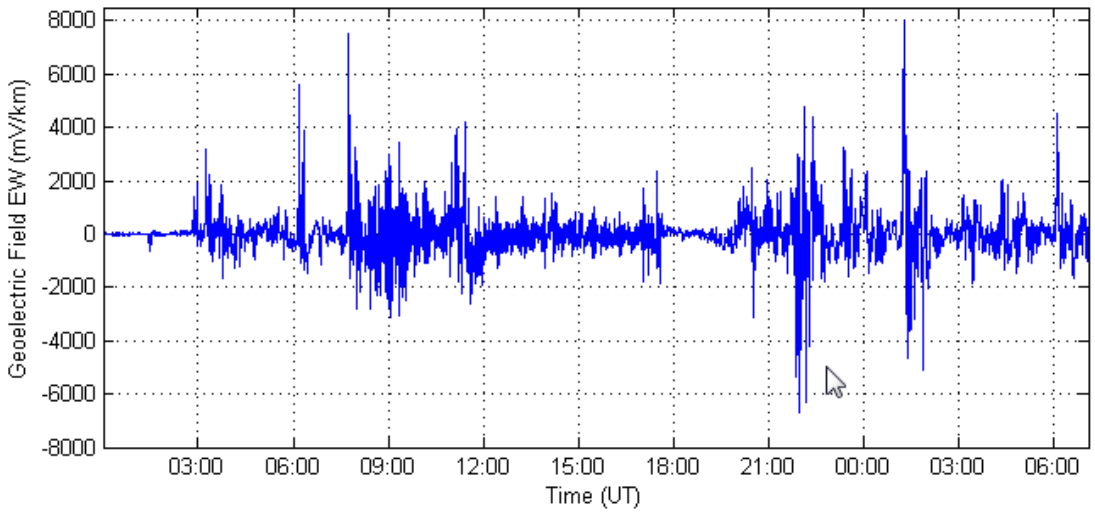


Figure 4: Benchmark Geoelectric Field ~~Waveshape~~Waveform - E_E (Eastward)

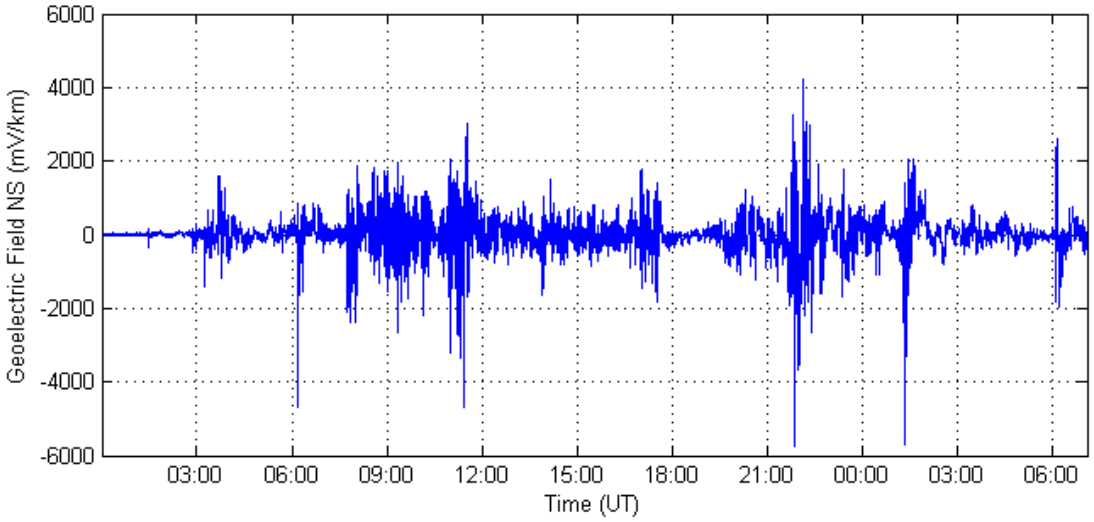


Figure 5: Benchmark Geoelectric Field ~~Waveshape~~Waveform – E_N (Northward)

Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event[10]

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds.[11] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor β_S.

[10] Refer to the Supplemental GMD Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[11] The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

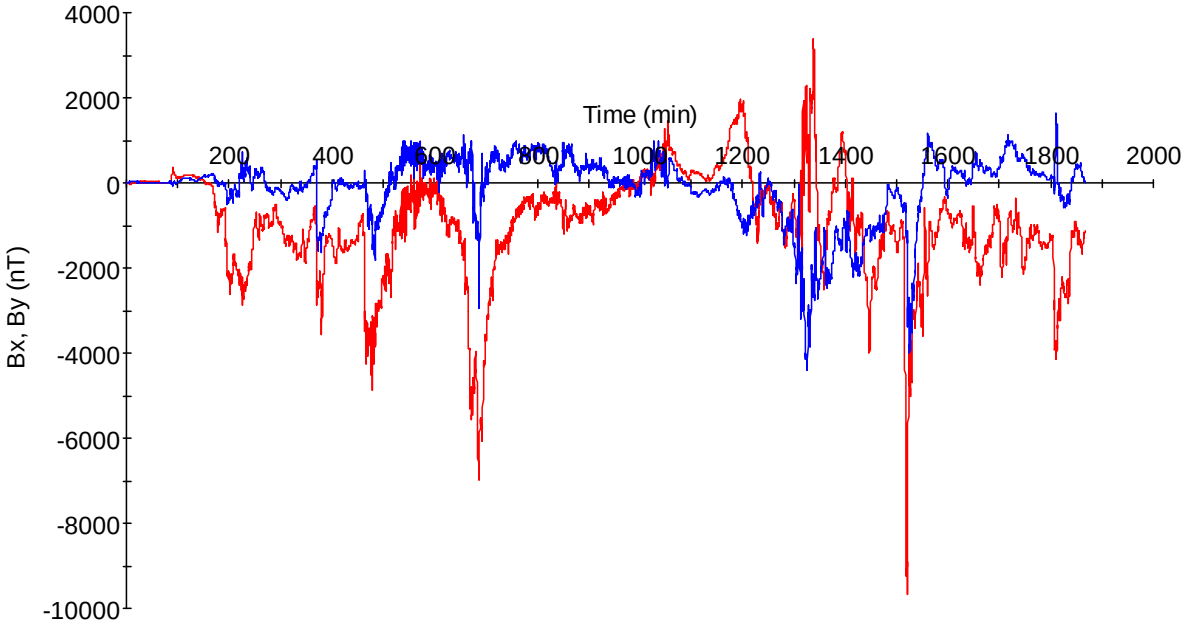


Figure 6: Supplemental Geomagnetic Field Waveform. Red B_n (Northward), Blue B_e (Eastward)

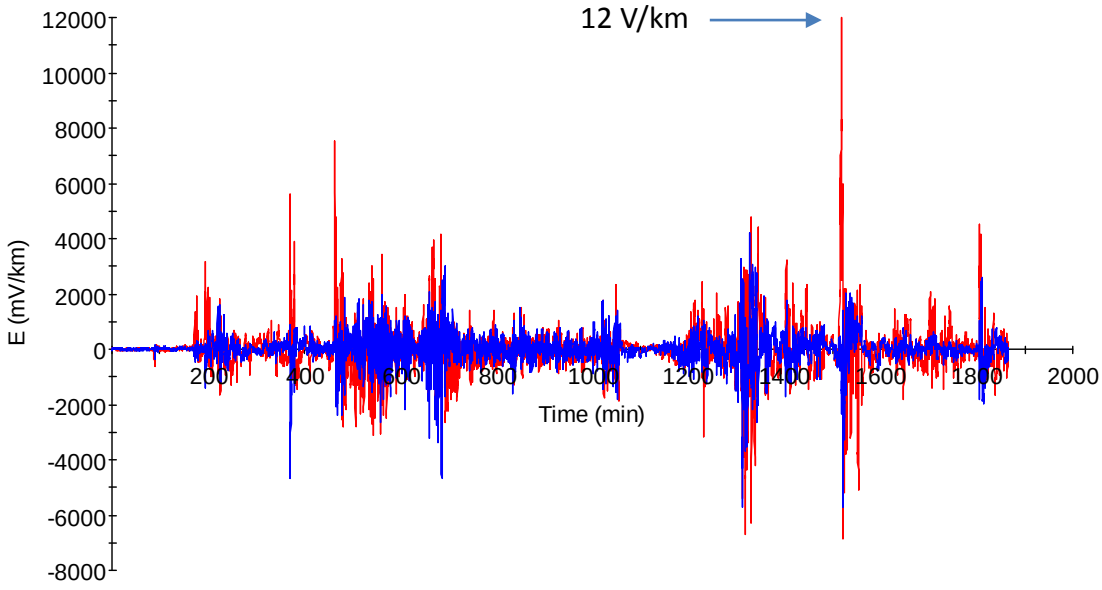


Figure 7: Supplemental Geoelectric Field Waveform. ~~Red~~ Blue E_n (Northward), ~~Blue~~ Red E_e (Eastward)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The following evidence retention ~~periods~~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 ~~CEA~~Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

~~The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner~~The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.

- For Requirements R1, R2, R3, R5, R6, R9, and ~~R6~~R10, each responsible entity shall retain documentation as evidence for five years.
- For ~~Requirement~~Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.
- For Requirement R7, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements R11 and R12, each responsible entity shall retain documentation as evidence for three years.

~~If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.~~

~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~

~~**1.3. Compliance Monitoring and Assessment Processes:**~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~**1.4. Additional Compliance Information**~~

~~None~~

- For Requirements R11 and R12, each responsible entity shall retain documentation as evidence for three years.

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

Table of Compliance Elements

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Long-term Planning~~	~~Lower~~	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models ~~and~~, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s).~~, and implementing process(es) to obtain

						GMD measurement data as specified in this standard.
R2	~~Long-term Planning~~	~~High~~	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~.	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~.
R3	~~Long-term Planning~~	~~Medium~~	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the ~~benchmark~~ GMD ~~event~~events described in Attachment 1 as required.
R4	~~Long-term Planning~~	~~High~~	The responsible entity completed a benchmark GMD	The responsible entity's completed benchmark GMD	The responsible entity's completed benchmark GMD	The responsible entity's completed benchmark GMD

			Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	Vulnerability Assessment failed to satisfy one of elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last benchmark GMD Vulnerability Assessment.	Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last benchmark GMD Vulnerability Assessment.	Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.
R5	~~Long-term Planning~~	~~Medium~~	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each

			equal to 100 calendar days after receipt of a written request.	than or equal to 110 calendar days after receipt of a written request.	receipt of a written request.	applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6	~~Long-term Planning~~	~~Medium~~	The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal

			its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.
R7			The responsible entity's Corrective Action Plan failed to comply with one of the elements in	The responsible entity's Corrective Action Plan failed to comply with two of the elements in	The responsible entity's Corrective Action Plan failed to comply with three of the elements in	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements

			Requirement R7, Parts 7.1 through 7.5.	Requirement R7, Parts 7.1 through 7.5.	Requirement R7, Parts 7.1 through 7.5.	in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.
R8			The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.4;	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy four of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR

				Vulnerability Assessment.		The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.
R9			The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R10			The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned

			transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified	applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

				in Requirement R9, Part 9.1; OR The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	in Requirement R9, Part 9.1; OR The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.
R11			N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.
R12			N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

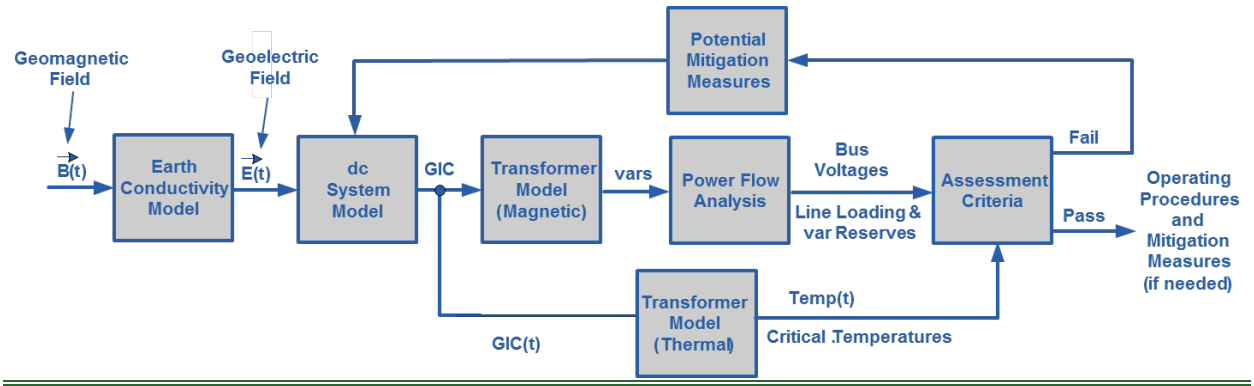
None.

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	
2	TBD	Revised to respond to directives in FERC Order No. 830.	Revised

Guidelines and Technical Basis

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process.

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page at:

~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx~~http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

Supplemental GMD Event (Attachment 1)

The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. A white paper that includes the event description and analysis is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:
http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R2

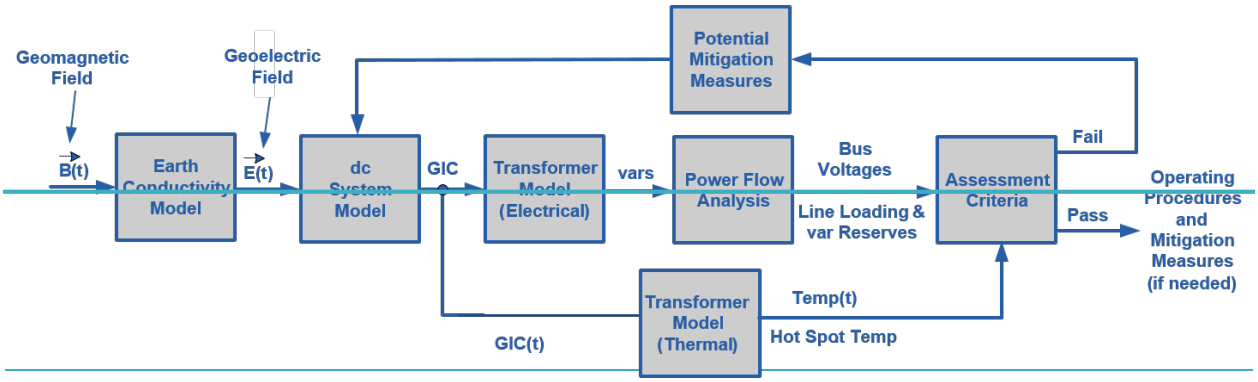
A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*. The guide is available at:
http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.

Requirement R4

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

~~The diagram below provides an overall view of the GMD Vulnerability Assessment process:~~



Requirement R5

The ~~transformer~~benchmark thermal impact assessment of transformers specified in Requirement R6 is based on GIC information for the ~~Benchmark~~benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for ~~transformer~~the benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

GIC(t) provided in Part 5.2 is used to convert the steady ~~-~~state GIC flows to time-series GIC data for ~~transformer~~the benchmark thermal impact assessment~~.~~ of transformers. This information may be needed by one or more of the methods for performing a benchmark thermal impact assessment. Additional information is in the following section and the thermal impact assessment white paper.

The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R6

The benchmark thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment* white paper ~~posted on the project page.~~ The ERO enterprise has endorsed the white paper as Implementation Guidance for this requirement. The white paper is posted on the NERC compliance guidance page: ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx~~

http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper posted on the Related Information page for ~~project~~TPL-007-1. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The benchmark threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *GMD Planning Guide*. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Requirement R8

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The supplemental GMD Vulnerability Assessment process is similar to the benchmark GMD Vulnerability Assessment process described under Requirement R4.

Requirement R9

The supplemental thermal impact assessment specified of transformers in Requirement R10 is based on GIC information for the supplemental GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R9 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.

GIC(t) provided in Part 9.2 is used to convert the steady state GIC flows to time-series GIC data for the supplemental thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a supplemental thermal impact assessment. Additional information is in the following section.

The peak GIC value of 85 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R10

The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment* white paper discussed in the Requirement R6 section above. A revised version of the Transformer Thermal Impact Assessment white paper has been developed to include updated information pertinent to the supplemental GMD event and supplemental thermal impact assessment. This revised white paper is posted on the project page at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the revised *Screening*

Criterion for Transformer Thermal Impact Assessment white paper posted on the project page. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.

The supplemental threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R11

Technical considerations for GIC monitoring are contained in the NERC 2012 GMD Report (see Chapter 6). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer. Data from GIC monitors is useful model validation and situational awareness.

Responsible entities consider the following in developing a process for obtaining GIC monitor data:

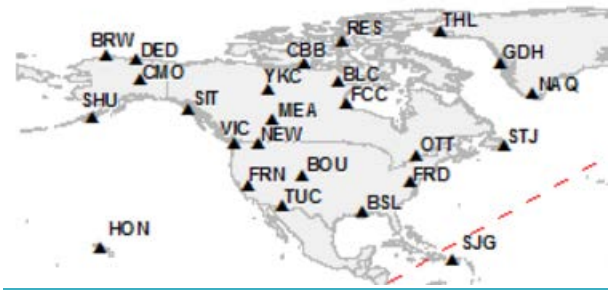
- **Monitor locations.** An entity's operating process may be constrained by location of existing GIC monitors. However, when planning for additional GIC monitoring installations consider that data from monitors located in areas found to have high GIC based on system studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (e.g., subways or light rail) may be unreliable.
- **Monitor specifications.** Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider monitor data range (e.g., -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.
- **Sampling Interval.** An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.
- **Collection Periods.** The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.
- **Data format.** Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow. Positive reference is flow from ground into transformer neutral. Time fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.
- **Data retention.** The entity's process should specify data retention periods, for example 1 year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.

- **Additional information.** The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (e.g., three-phase or single-phase).

Requirement R12

Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:

- Observatories such as those operated by U.S. Geological Survey and Natural Resources Canada, see figure below for locations (http://www.intermagnet.org/):



- Research institutions and academic universities;
- Entities with installed magnetometers.

Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the latest version of the Intermagnet Technical Reference Manual, which is available at:
http://www.intermagnet.org/publications/intermag_4-6.pdf

Rationale:

During development of ~~this standard~~TPL-007-1, text boxes were embedded within the standard to explain the rationale for various parts of the standard. ~~Upon BOT approval, the~~The text from the rationale text boxes was moved to this section~~.~~ upon approval of TPL-007-1 by the NERC Board of Trustees. In developing TPL-007-2, the SDT has made changes to the sections below only when necessary for clarity. Changes are marked with brackets [ ].

Rationale for Applicability:
Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

Rationale for R1:
In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Rationale for R2:
A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.

The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.

Rationale for R3:
Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.

Rationale for R4:
The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R5:
This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.

GIC(t) provided in Part 5.2 can alternatively be used to convert the steady -state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the Transformer Thermal Impact Assessment white paper:

~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx~~

[http://www.nerc.com/pa/comp/guidance/Pages/default.aspx]

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R6:

The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase~~.~~ [for the benchmark GMD event]. Only those transformers that experience an effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the Thermal Screening Criterion white paper.

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the Transformer Thermal Impact Assessment white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R7:
Corrective Action Plans are defined in the NERC Glossary of Terms:

> *A list of actions and an associated timetable for implementation to remedy a specific problem.*

Corrective Action Plans must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of the ~~Benchmark~~[Bb]enchmark GMD event, based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment. Chapter 5 of the NERC GMD Task Force *GMD Planning Guide* provides a list of mitigating measures that may be appropriate to address an identified performance issue.

The provision of information in Requirement R7, Part 7.3~~,~~ [Part 7.5 in TPL-007-2], shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for Table 3:
Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74~~.~~ [The scaling factor associated with the benchmark GMD event for the Florida earth model (FL-1) has been updated to 0.76 in TPL-007-2 based on the earth model published on the USGS public website.]

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Violation Risk Factor and Violation Severity Level Justifications

TPL-007-2 – Transmission System Planned Performance for Geomagnetic Disturbance Events

This document provides the Standard Drafting Team's (SDT) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in TPL-007-2 – Transmission System Planned Performance for Geomagnetic Disturbance Events. 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 ERO Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - 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 Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission 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
The Commission expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission 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 - 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

FERC's 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 – TPL-007-2, R1	
Proposed VRF	**Low**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report. N/A
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 Lower is consistent with Reliability Standard TPL-001-4 Requirement R7, which requires the Planning Coordinator, in conjunction with each of its Transmission Planners, to identify each entity's individual and joint responsibilities for performing required studies for the Planning Assessment. Proposed TPL-007-2 Requirement R1 requires Planning Coordinators, in conjunction with Transmission Planners, to identify individual and joint responsibilities for maintaining models and performing studies needed to complete the benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in the Standard.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A VRF of Lower is consistent with the NERC VRF definition. The requirement for identifying individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models, performing GMD studies, and obtaining GMD measurement data, 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, control, or restore the Bulk Electric System under conditions of a GMD event.

VRF Justifications – TPL-007-2, R1	
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.

Proposed VSLs – TPL-007-2, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in the Standard.

VSL Justifications – TPL-007-2, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL is not changed in TPL-007-2.
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 VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL is worded consistently with the corresponding requirement.

Consistent 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 – TPL-007-2, R2	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
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 is consistent with the VRF for Reliability Standard TPL-001-4 Requirement R1 as amended in NERC's filing dated August 29, 2014, which requires Transmission Planners and Planning Coordinators to maintain models within its respective planning area for performing studies needed to complete its Planning Assessment. Proposed TPL-007-2, Requirement R2 requires responsible entities to maintain System models and GIC System models of the responsible entity's planning area for performing the studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. The System Models and GIC System Models serve as the foundation for all conditions and events that are required to be studied and evaluated in the benchmark and supplemental GMD Vulnerability Assessments. For this reason, failure to maintain models of the responsible entity's planning area for performing GMD studies could, under GMD conditions that are as severe as the benchmark and supplemental GMD event, place the Bulk Electric System 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. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the study or studies or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

VSL Justifications – TPL-007-2, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL is not changed in TPL-007-2.
FERC VSL G2	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-2, R2	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL 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 – TPL-007-2, R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
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 is consistent with Reliability Standard TPL-001-4 Requirement R5 which requires Transmission Planners and Planning Coordinators to have criteria for acceptable System steady state voltage limits. Proposed TPL-007-2 Requirement R4 requires responsible entities to have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event; these criteria may be different from the voltage limits determined in Reliability Standard TPL-001-4 Requirement R5.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to have criteria for acceptable System steady state voltage limits for its System during a GMD planning event could 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 during an actual GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not have criteria for acceptable

Proposed VSLs – TPL-007-2, R3			
			System steady state voltage performance for its System during the GMD events described in Attachment 1 as required.

VSL Justifications – TPL-007-2, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL is not changed in TPL-007-2.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.

VSL Justifications – TPL-007-2, R3	
"Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL 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 – TPL-007-2, R4	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
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 is consistent with Reliability Standard TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to prepare an annual Planning Assessment to ensure its portion of the Bulk Electric System meets performance criteria. Proposed TPL-007-2 Requirement R4 requires responsible entities to complete a benchmark GMD Vulnerability Assessment to ensure the system meets performance criteria during the benchmark GMD event.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to complete a benchmark GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System 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. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 60 calendar	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy one of elements listed	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy two of the elements	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy three of the elements

Proposed VSLs – TPL-007-2, R4			
months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last benchmark GMD Vulnerability Assessment.	listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last benchmark GMD Vulnerability Assessment.	listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.

VSL Justifications – TPL-007-2, R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of	The VSL is not changed in TPL-007-2.

VSL Justifications – TPL-007-2, R4	
Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A	The proposed VSL is not based on a cumulative number of violations.

VSL Justifications – TPL-007-2, R4	
Cumulative Number of Violations	

VRF Justifications – TPL-007-2, R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
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 is consistent with Reliability Standard MOD-032-1 Requirement R2 which requires applicable entities to provide modeling data to Transmission Planners and Planning Coordinators. A VRF of Medium is also consistent with Reliability Standard IRO-010-2 Requirement R3 which requires entities to provide data necessary for the Reliability Coordinator to perform its Operational Planning Analysis and Real-time Assessments. Proposed TPL-007-2 Requirement R5 requires responsible entities to provide specific geomagnetically-induced currents (GIC) flow information to Transmission Owners and Generator Owners for performing transformer thermal impact assessments.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to provide GIC flow information for the benchmark GMD event could 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 during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R5			
Lower	**Moderate**	**High**	**Severe**
The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.

VSL Justifications – TPL-007-2, R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VLS is not changed in TPL-007-2.

VSL Justifications – TPL-007-2, R5	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to 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 2a: The proposed VSL is not binary.
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL 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 – TPL-007-2, R6	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
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 is consistent with Reliability Standard FAC-008-3 Requirement R6 which requires Transmission Owners and Generator Owners to have Facility Ratings for all solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation. Proposed TPL-007-2 Requirement R6 requires responsible entities to conduct a benchmark thermal impact assessment for solely and jointly owned applicable transformers and provide results including suggested actions to mitigate identified impacts to planning entities.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to conduct a benchmark transformer thermal impact assessment could 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 during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R6			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1;

Proposed VSLs – TPL-007-2, R6			
of receiving GIC flow information specified in Requirement R5, Part 5.1.	of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	OR The responsible entity failed to include three of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.

VSL Justifications – TPL-007-2, R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL is not changed in TPL-007-2.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-2, R6	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL 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 – TPL-007-2, R7	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
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 is consistent with Reliability Standard TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to include a Corrective Action Plan that addresses identified performance issues in the annual Planning Assessment. Proposed TPL-007-2 Requirement R7 requires responsible entities to develop a Corrective Action Plan when results of the benchmark GMD Vulnerability Assessment indicate that the System does not meet performance requirements. While Reliability Standard TPL-001-4 has a single requirement for performing the Planning Assessment and developing the Corrective Action Plan, proposed TPL-007-2 has split the requirements for performing a benchmark GMD Vulnerability Assessment and developing the Corrective Action Plan into two separate requirements because the transformer thermal impact assessments performed by Transmission Owners and Generator Owners must be considered. The sequencing with separate requirements follows a logical flow of the GMD Vulnerability Assessment process.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to develop a Corrective Action Plan that addresses issues identified in a GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, place the Bulk Electric System 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. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R7			
Lower	**Moderate**	**High**	**Severe**
The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

VSL Justifications – TPL-007-2, R7	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed requirement is a significant revision to TPL-007-2 to address the directive for Corrective Action Plan deadlines contained in FERC Order No. 830. There is no prior compliance obligation related to the directive. However, the requirement uses the same construct for a graduated scale as TPL-007-1 Requirement R7 and is similar to Reliability Standard TPL-001-4, Requirement R2.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-2, R7	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL 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 – TPL-007-2, R8	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
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 is consistent with Reliability Standard TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to prepare an annual Planning Assessment to ensure its portion of the Bulk Electric System meets performance criteria. The proposed requirement is also consistent with approved TPL-007-1 Requirement R4 (unchanged in proposed TPL-007-2 Requirement R4). Proposed TPL-007-2 Requirement R8 requires responsible entities to complete a supplemental GMD Vulnerability Assessment to assess system performance during a supplemental GMD event.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to complete a supplemental GMD Vulnerability Assessment could, under GMD conditions that are as severe as the supplemental GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures by precluding responsible entities from considering actions to mitigate risk of Cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a supplemental GMD	The responsible entity's completed supplemental GMD	The responsible entity's completed supplemental GMD	The responsible entity's completed supplemental GMD

Proposed VSLs – TPL-007-2, R8			
Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.4;	Vulnerability Assessment failed to satisfy two of elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	Vulnerability Assessment failed to satisfy four of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.

VSL Justifications – TPL-007-2, R8	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to supplemental GMD Vulnerability Assessment. However, the requirement is similar to approved TPL-007-1, Requirement R4 (unchanged in proposed TPL-007-2 Requirement R4). That requirement also has a graduated scale for VSLs.
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 VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications – TPL-007-2, R8	
Consistent 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 – TPL-007-2, R9	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
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 is consistent with approved TPL-007-1 Requirement R5 (unchanged in proposed TPL-007-2 Requirement R5) which requires responsible entities to provide specific geomagnetically-induced currents (GIC) flow information to Transmission Owners and Generator Owners for performing transformer thermal impact assessments.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to provide GIC flow information for the supplemental GMD event could 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 during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R9			
Lower	**Moderate**	**High**	**Severe**
The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner

Proposed VSLs – TPL-007-2, R9			
90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	110 calendar days after receipt of a written request.	that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.

VSL Justifications – TPL-007-2, R9	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to supplemental GMD Vulnerability Assessment. However, the requirement is similar to approved TPL-007-1, Requirement R5 (unchanged in proposed TPL-007-2 Requirement R5). That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-2, R9	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL 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 – TPL-007-2, R10	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
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 is consistent with approved TPL-007-1 Requirement R6 (unchanged in proposed TPL-007-2 Requirement R6), which requires responsible entities to conduct a benchmark thermal impact assessment for solely and jointly owned applicable transformers and provide results including suggested actions to mitigate identified impacts to planning entities.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to conduct a supplemental transformer thermal impact assessment could 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 during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R10			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or	The responsible entity failed to conduct a supplemental thermal impact assessment for more	The responsible entity failed to conduct a supplemental thermal impact assessment for more	The responsible entity failed to conduct a supplemental thermal impact assessment for more

Proposed VSLs – TPL-007-2, R10			
less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR	than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR	than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR The responsible entity failed to include three of the required elements as listed in

Proposed VSLs – TPL-007-2, R10			
	The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	Requirement R10, Parts 10.1 through 10.3.

VSL Justifications – TPL-007-2, R10	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to supplemental thermal impact assessment. However, the requirement is similar to approved TPL-007-1, Requirement R6 (unchanged in proposed TPL-007-2 Requirement R6). That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary.

VSL Justifications – TPL-007-2, R10	
Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL 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 – TPL-007-2, R11	
Proposed VRF	**Lower**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
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 Lower is consistent with approved Reliability Standards requiring entities to implement processes to obtain data. These include Reliability Standard MOD-032-1 Requirement R1 and Reliability Standard IRO-010-2 Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Lower is consistent with the NERC VRF Definition. Failure to obtain GIC monitor data from at least one GIC monitor located in the system would not 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	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R11			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning

Proposed VSLs – TPL-007-2, R11			
			Coordinator's GIC System Model.

VSL Justifications – TPL-007-2, R11	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation for this requirement.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.

VSL Justifications – TPL-007-2, R11	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL 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 – TPL-007-2, R12	
Proposed VRF	**Lower**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
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 Lower is consistent with approved Reliability Standards requiring entities to implement processes to obtain data. These include Reliability Standard MOD-032-1 Requirement R1 and Reliability Standard IRO-010-2 Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Lower is consistent with the NERC VRF Definition. Failure to obtain geomagnetic field data for the planning area would not 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	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R12			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

VSL Justifications – TPL-007-2, R12	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation for this requirement.
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 VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications – TPL-007-2, R12	
Consistent 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.

Consideration of Directives

Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events

Order No. 830, 156 FERC ¶ 61,215 (Sep. 22, 2016)

approving Reliability Standard TPL-007-1

#	P	Directive/Guidance	Resolution
1)	**PP 44** 47-49	**MODIFY THE BENCHMARK GMD EVENT re SPATIAL AVERAGING** P44: "[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."	The directive is addressed in proposed TPL-007-2 through Requirements for applicable entities to perform supplemental GMD Vulnerability Assessments based on the supplemental GMD event. The supplemental GMD event is a defined event for assessing system performance that is not based on spatially-averaged data. The supplemental GMD event is described in the standard drafting team's (SDT) white paper available on the project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx
2)	**P65**	**REVISE R6 RE SPATIAL AVERAGING** 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	The directive is addressed in proposed TPL-007-2 Requirements R9 and R10. Applicable entities use geomagnetically-induced current (GIC) information for the supplemental GMD event to perform supplemental thermal impact assessments of applicable power

#	P	Directive/Guidance	Resolution
		to apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient and effective alternative, when conducting thermal impact assessments."	transformers. Requirement R9 obligates responsible Planning Coordinators and Transmission Planners to provide GIC flow information to Transmission Owners and Generator Owners for performing supplemental thermal impact assessments. The GIC flow information is based on the supplemental GMD event. Requirement R10 obligates Transmission Owners and Generator Owners to perform supplemental thermal impact assessments on applicable power transformers and provide results to responsible Planning Coordinators and Transmission Planners.
3)	**PP 88** 90, 91, 92	**REVISE STANDARD TO REQUIRE COLLECTION OF GMD DATA** 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." *GIC Requirements* P 91: "Each responsible entity that is a transmission owner should be	The directive is addressed in proposed TPL-007-2 Requirements R11 and R12. Requirement R11 obligates responsible Planning Coordinators and Transmission Planners to implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. The SDT described GIC data collection criteria in the guidance section to promote consistency in achieving the reliability objective and provide responsible entities with flexibility to tailor procedures to their planning area. The guidance addresses the following considerations: monitor locations, monitor specifications, sampling interval, collection periods, data format, and data retention.

#	P	Directive/Guidance	Resolution
		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. 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." *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." *** 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).	Requirement R12 obligates responsible Planning Coordinators and Transmission Planners to implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. Sources of geomagnetic field data include government observatories, installed equipment owned or operated by the entity, and third-party sources. Entities are referred to INTRAMAGNET guidance for criteria and considerations including data sampling rate (10-s or faster) and data format. By requiring responsible Planning Coordinators and Transmission Planners to obtain geomagnetic field data for their planning areas, the requirement ensures data is obtained from diverse geographic areas (latitudes and longitudes) of the North American Bulk-Power System.

#	P	Directive/Guidance	Resolution
		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."	
4)	**P 101, 102**	**REVISE TPL-007 TO REQUIRE DEADLINES FOR THE DEVELOPMENT AND COMPLETION OF CORRECTIVE ACTION PLANS** 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 directive is addressed in proposed TPL-007-2 Requirement R7. Part 7.2 specifies that responsible entities must develop Corrective Action Plans (CAP) within one year of completing the benchmark GMD Vulnerability Assessment. Part 7.3 requires responsible entities to include a timetable in the CAP that must specify: • Implementation of non-hardware mitigation within two years of the development of the CAP; and • Implementation of hardware mitigation within four years of the development of the CAP. Part 7.4 provides responsible entities with flexibility to revise the CAP and timetables if situations beyond the control of the responsible entity prevent implementation of the CAP within the specified timetable. The provision is necessary to account for potential planning, siting, budgeting approval, or regulatory uncertainties associated with transmission system projects that are not within the responsible entity's control. Responsible entities are obligated to document the revised CAP and update the revised CAP every 12 calendar months until implemented.

#	P	Directive/Guidance	Resolution
			Requirement R8 requires responsible entities to complete a supplemental GMD Vulnerability Assessment, based on the supplemental GMD event, to evaluate localized enhancements of geomagnetic field during a severe GMD event that could potentially affect the reliable operation of the Bulk-Power System. Localized enhancements of geomagnetic field can result in geoelectric field values above the spatially-averaged benchmark in a local area. Part 8.3 specifies that if the responsible entity concludes that there is Cascading caused by the supplemental GMD event, then the responsible entity shall conduct an analysis of possible actions to reduce the likelihood or mitigate the impacts and the event. Proposed TPL-007-2 does not require responsible entities to implement a Corrective Action Plan to address impacts identified in the supplemental GMD Vulnerability Assessment because mandatory mitigation on the basis of the supplemental GMD Vulnerability Assessment may not provide effective reliability benefit or use industry resources optimally. As discussed in the Supplemental GMD Event Description white paper, the supplemental GMD event is based on a small number of observed localized enhancement events that provide only general insight into the geographic size of localized events during severe solar storms. Additionally, the state-of-the-art modeling tools do not provide entities with capabilities to realistically model localized enhancements within a severe GMD event, and as a result entities may need to employ conservative approaches in the GMD Vulnerability Assessment such as applying the localized peak geoelectric field over an

#	P	Directive/Guidance	Resolution
			entire planning area. The approach taken in TPL-007-2 to mitigating impacts identified in the supplemental GMD Vulnerability Assessment provides responsible entities with flexibility to consider and select actions based on entity-specific factors. This is similar to the approach taken in Reliability Standard TPL-001-4 for extreme events (TPL-001-4 Requirement R3 Part 3.5).

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Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation
Reliability Standard TPL-007-2

Applicable Standard(s)

- TPL-007-2 - Transmission System Planned Performance for Geomagnetic Disturbance Events

Requested Retirement(s)

- TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Standard(s)

None

Applicable Entities

- Planning Coordinator with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;
- Transmission Planner with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;
- Transmission Owner who owns a Facility or Facilities specified in Section 4.2 of the standard;
- Generator Owner who owns a Facility or Facilities specified in Section 4.2 of the standard.

Section 4.2 states that the standard applies to facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Terms in the NERC Glossary of Terms

There are no new, modified, or retired terms.

Background

On September 22, 2016, the Federal Energy Regulatory Commission (FERC) issued Order No. 830 approving Reliability Standard TPL-007-1 and its associated five-year Implementation Plan. In the Order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 2018.

General Considerations

This Implementation Plan is intended to integrate the new requirements in TPL-007-2 with the GMD Vulnerability Assessment process that is being implemented through approved TPL-007-1. At the time of the May 2018 filing deadline, many requirements in approved standard TPL-007-1 that lead to completion of the GMD Vulnerability Assessment will be in effect. Furthermore, many entities

may be taking steps to complete studies or assessments that are required by future enforceable requirements in TPL-007-1. The Implementation Plan phases in the requirements in TPL-007-2 based on the effective date of TPL-007-2, as follows:

- **Effective Date before January 1, 2021**. Implementation timeline supports applicable entities completing new requirements for supplemental GMD Vulnerability Assessments concurrently with requirements for the benchmark GMD Vulnerability Assessment (concurrent effective dates).

- **Effective Date on or after January 1, 2021**. Implementation timeline supports applicable entities completing the benchmark GMD Vulnerability Assessments before new requirements for supplemental GMD Vulnerability Assessments become effective.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Standard TPL-007-2

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is three (3) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

If TPL-007-2 becomes effective before January 1, 2021

Implementation timeline supports applicable entities completing new requirements for supplemental GMD Vulnerability Assessments concurrently with requirements for the benchmark GMD Vulnerability Assessment (concurrent effective dates).

Compliance Date for TPL-007-2 Requirement R9

Entities shall not be required to comply with Requirement R9 until six (6) months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R11 and R12
Entities shall not be required to comply with Requirements R11 and R12 until 24 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R6 and R10
Entities shall not be required to comply with Requirements R6 and R10 until 30 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R3, R4, and R8
Entities shall not be required to comply with Requirements R3, R4, and R8 until 42 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R7
Entities shall not be required to comply with Requirement R7 until 54 months after the effective date of Reliability Standard TPL-007-2.

If TPL-007-2 becomes effective on or after January 1, 2021

Implementation timeline supports applicable entities completing the benchmark GMD Vulnerability Assessments before new requirements for supplemental GMD Vulnerability Assessments become effective.

Compliance Date for TPL-007-2 Requirements R3 and R4
Entities shall not be required to comply with Requirements R3 and R4 until 12 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R7, R11, and R12
Entities shall not be required to comply with Requirements R7, R11, and R12 until 24 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R9
Entities shall not be required to comply with Requirement R9 until 36 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R10
Entities shall not be required to comply with Requirement R10 until 60 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R8
Entities shall not be required to comply with Requirement R8 until 72 months after the effective date of Reliability Standard TPL-007-2.

Retirement Date

Standard TPL-007-1

Reliability Standard TPL-007-1 shall be retired immediately prior to the effective date of TPL-007-2 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

Transmission Owners and Generator Owners are not required to comply with Requirement R6 prior to the compliance date for Requirement R6, regardless of when GIC flow information specified in Requirement R5 Part 5.1 is received.

Transmission Owners and Generator Owners are not required to comply with Requirement R10 prior to the compliance date for Requirement R10, regardless of when GIC flow information specified in Requirement R9 Part 9.1 is received.

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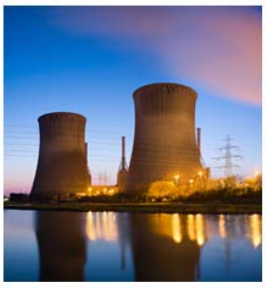
Supplemental Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation

June 2017

RELIABILITY | ACCOUNTABILITY



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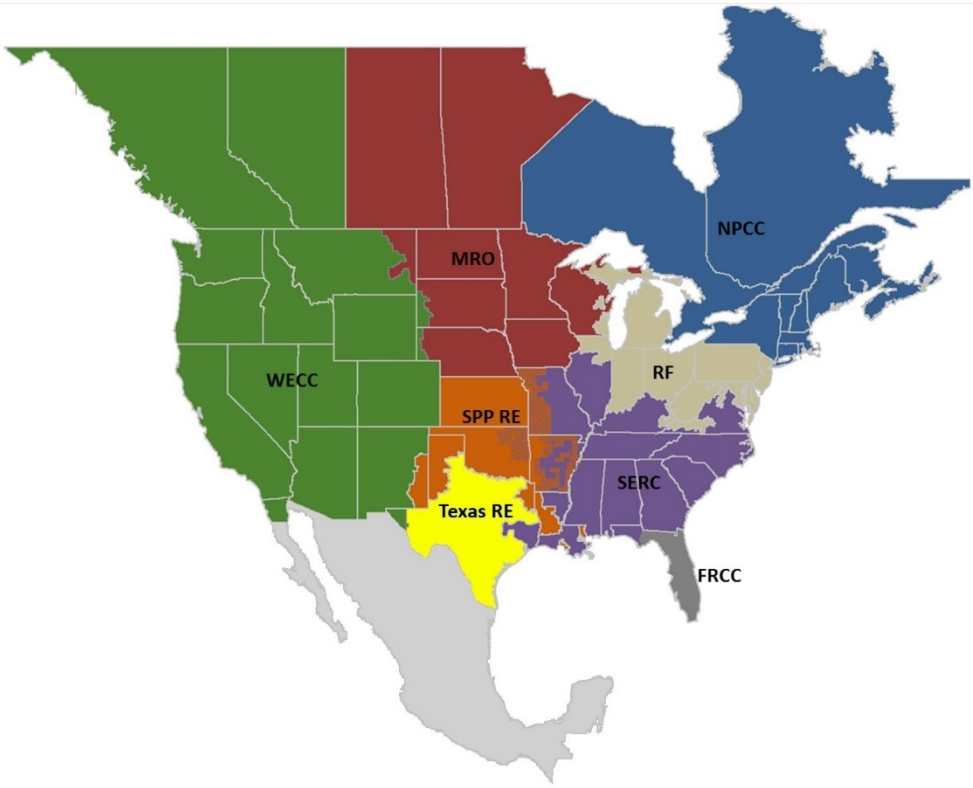
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

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



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

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

Background

Proposed TPL-007-2 includes requirements for entities to perform two types of GMD Vulnerability Assessments to evaluate the potential impacts of GMD events on the Bulk Electric System (BES):

- The benchmark GMD Vulnerability Assessment is based on the benchmark GMD event associated with TPL-007-1 which was approved by the Federal Energy Regulatory Commission (FERC) in Order No. 830 in September 2016. The benchmark GMD event is derived from spatially-averaged geoelectric field values to address potential wide-area effects that could be caused by a severe 1-in-100 year GMD event.[1]
- The supplemental GMD Vulnerability Assessment, based on the supplemental GMD event described in this white paper, is used by entities to evaluate localized enhancements of geomagnetic field during a severe GMD event that "could potentially affect the reliable operation of the Bulk-Power System".[2] Localized enhancements of geomagnetic field can result in geoelectric field values above the spatially-averaged benchmark in a local area.

The purpose of the supplemental geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance for a GMD event which includes a local enhancement of the geomagnetic field. In addition to varying with time, geomagnetic fields can be spatially non-uniform with higher and lower strengths across a region. This spatial non-uniformity has been observed in a number of GMD events, so localized enhancement of field strength above the average value is considered. The supplemental GMD event defines the geomagnetic and geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a supplemental GMD Vulnerability Assessment.

General Characteristics

The supplemental GMD event described herein takes into consideration observed characteristics of a local geomagnetic field enhancement, recognizing that the science and understanding of these events is evolving. Based on observations and initial assessments, the characteristics of local enhancements include:

- Geographic area – The extent of local enhancements is on the order of 100km in North-South (latitude) direction but longer in East-West (longitude) direction. Further description of the geographic area is provided later in the white paper.
- Amplitude – The amplitude of the resulting geoelectric field is significantly higher than the geoelectric field that is calculated in the spatially-averaged Benchmark GMD event.
- Duration – The local enhancement in the geomagnetic field occurs over a time period of 2-5 minutes.
- Geoelectric field waveform – The supplemental GMD event waveform is the benchmark GMD event waveform with the addition of a local enhancement. The added local enhancement has amplitude and duration characteristics described above. The geoelectric field waveform has a strong influence on the hot spot heating of transformer windings and structural parts since thermal time constants of the transformer and time to peak of storm maxima are both on the order of minutes. The frequency content of the rate of change of the magnetic field (dB/dt) is a function of the waveform, which in turn has a direct effect on the geoelectric field since the earth response to dB/dt is frequency-dependent. As with the benchmark GMD event, the supplemental GMD event waveform is based on magnetic field data recorded by the Natural Resources Canada (NRCan) Ottawa (OTT) geomagnetic observatory during the March 13-

[1] See *Benchmark Geomagnetic Disturbance Event Description* white paper, May 12, 2016. Filed by NERC in RM 15-11 on June 28, 2016.

[2] See Order No. 830 P. 47. On September 22, 2016, FERC directed NERC to develop modifications to the benchmark GMD event, included in TPL-007-1, such that assessments would not be based solely on spatially averaged data.

14 1989 event. This GMD event data was selected because analysis of recorded events indicates that the OTT observatory data for this period provides conservative results when performing thermal assessments of power transformers.[3]

[3] See *Benchmark Geomagnetic Disturbance Event Description* white paper, page 5 and Appendix I.

Supplemental GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [1]; thus, GMD events used in system planning should consider the probability that the event will occur, as well as the impact or consequences of such an event. The supplemental GMD event is composed of the following elements: 1) a reference peak geoelectric field amplitude (V/km) derived from statistical analysis of historical magnetometer data; 2) scaling factors to account for local geomagnetic latitude; 3) scaling factors to account for local earth conductivity; and 4) a reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

Supplemental GMD Event Geoelectric Field Amplitude

The supplemental GMD event field amplitude was determined through statistical analysis using the plane wave method [2]-[9] of geomagnetic field measurements from geomagnetic observatories in northern Europe [10] and the reference (Quebec) earth model shown in **Table 1** [11], supplemented by data from Greenland, Denmark and Alaska. For details of the statistical considerations, see Appendix I. The Quebec earth model is generally resistive and the geological structure is relatively well understood.

Table 1: Reference Earth Model (Quebec)

Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

The statistical analysis (see Appendix I) resulted in conservative peak geoelectric field amplitude of approximately 12 V/km. For steady-state GIC and load flow analysis, the direction of the geoelectric field is assumed to be variable meaning that it can be in any direction (Eastward, Northward, or a vectorial combination thereof).

The regional geoelectric field peak amplitude, E_{peak}, to be used in calculating GIC in the GIC system model can be obtained from the reference value of 12 V/km using the following relationship

$$E_{peak} = 12 \times \alpha \times \beta_S \text{ (V/km)} \quad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β_S is a scaling factor for the supplemental GMD event to account for the local earth conductivity structure (see Appendix II).

Supplemental Geomagnetic Field Waveform

The supplemental geomagnetic field waveform is the benchmark geomagnetic field waveform with the addition of a local enhancement. Both the benchmark and supplemental geomagnetic field waveforms are used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessments. The supplemental waveform includes a local enhancement, inserted at UT 1:18 March 14 in **Figure 1** below. This time corresponds to the largest calculated geoelectric fields during the benchmark GMD event. The amplitude of the local enhancement is based on a statistical analysis of a number of GMD events, discussed in Appendix I**.** The duration of the enhancement is based on the characteristics of observed localized enhancements as discussed in Appendix I.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data with a local enhancement was scaled up to the 60° reference geomagnetic latitude (see **Figure 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see **Figure 2**). Sampling rate for the geomagnetic field waveform is 10 seconds.

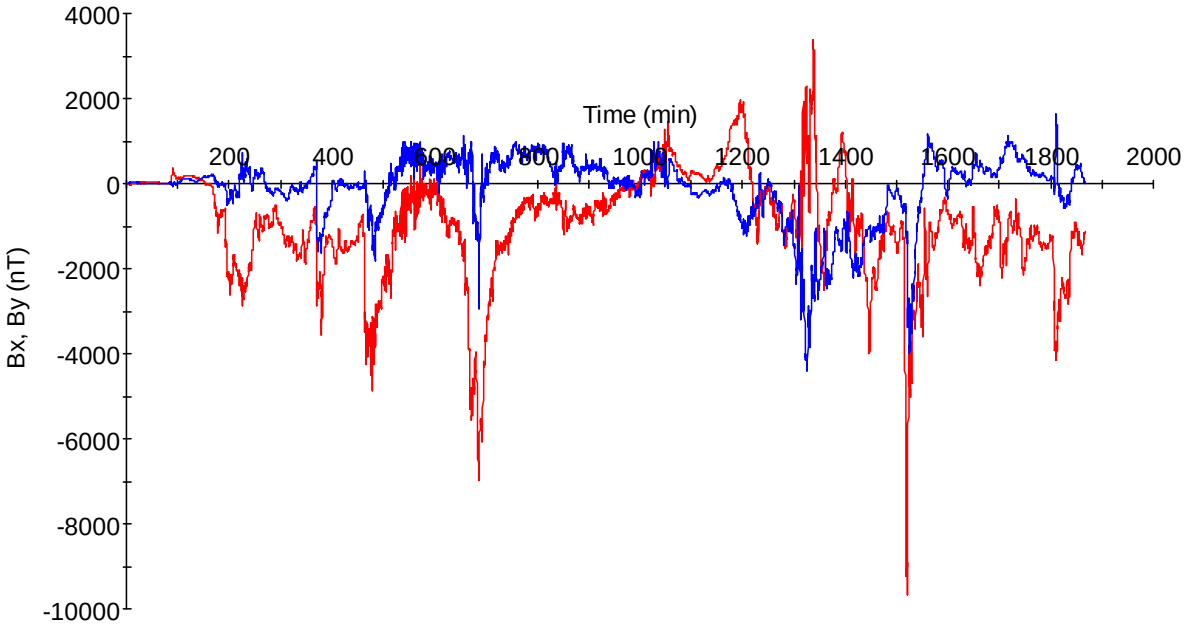


Figure 1: Supplemental Geomagnetic Field Waveform
Red B_x (Northward), Blue B_y (Eastward),
Referenced to pre-event quiet conditions

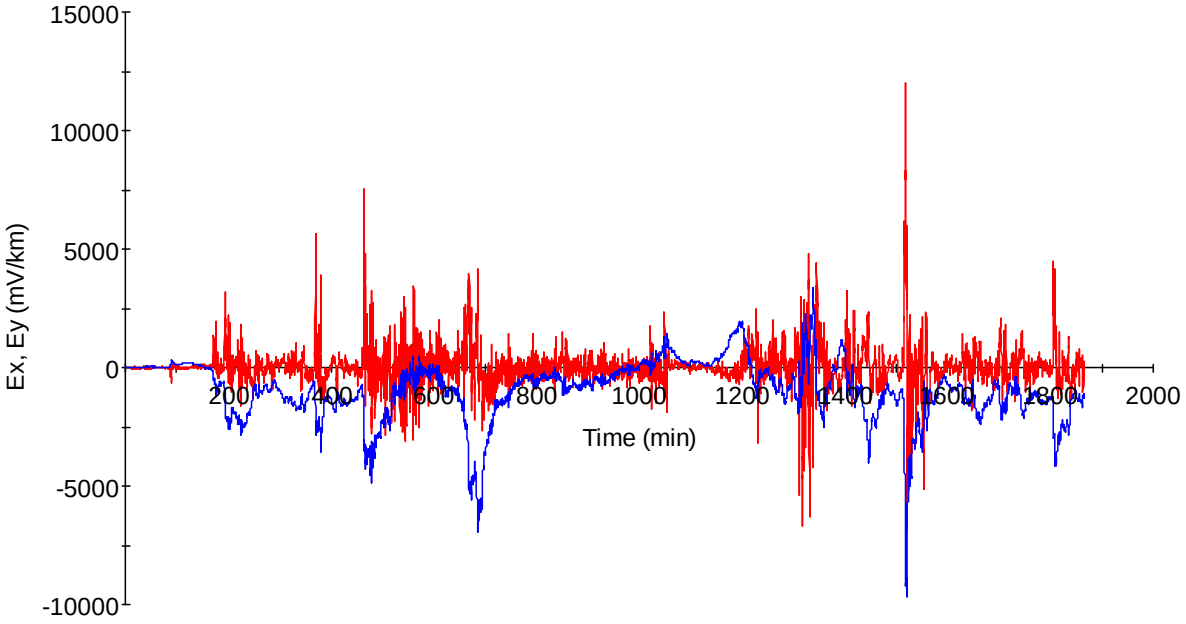


Figure 2: Supplemental Geoelectric Field Waveform
Red E_y (Eastward), Blue E_x (Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the supplemental GMD event.

Statistical Considerations

The peak geoelectric field amplitude of the supplemental GMD event was determined through statistical analysis of modern 10-second geomagnetic field data and corresponding calculated geoelectric field amplitudes. The objective of the analysis was to estimate the geoelectric field amplitude that is associated with a 1 in 100 year frequency of occurrence. The same data set and similar statistical techniques were used in determining the peak geoelectric field amplitude of the benchmark GMD event, including extreme value analysis discussed in the following section.[4] The fundamental difference in the supplemental GMD event amplitude is that it is based on observations taken at each individual station (i.e., localized measurements), in contrast with the spatially averaged geoelectric fields used in the *Benchmark Geomagnetic Disturbance Event Description* white paper.[5]

[4] See *Benchmark Geomagnetic Disturbance Event Description* white paper, Appendix I, pages 8-13.

[5] Averaging the geoelectric field values of stations in geographic groups is referred to as spatial averaging in the *Benchmark Geomagnetic Disturbance Event Description.* Spatial averaging was used to characterize GMD events over a geographic area relevant to the interconnected transmission system for purposes of assessing area effects such as voltage collapse and widespread equipment risk. See *Benchmark Geomagnetic Disturbance Event Description* white paper, Appendix I, pages 9-10.

Extreme Value Analysis

The objective of extreme value analysis is to describe the behavior of a stochastic process at extreme deviations from the median. In general, the intent is to quantify the probability of an event more extreme than any previously observed. In particular, we are concerned with estimating the 95% confidence interval of the maximum geoelectric field amplitude to be expected within a 100-year return period.[6]

The data set consists of 23 years of daily maximum geoelectric field amplitudes derived from individual stations in the IMAGE magnetometer chain, using the Quebec earth model as a reference. **Figure I-1** shows a scatter plot of geoelectric field amplitudes that exceed 2 V/km across the IMAGE stations. The plot indicates that there is seasonality in extreme observations associated with the 11-year solar cycle.

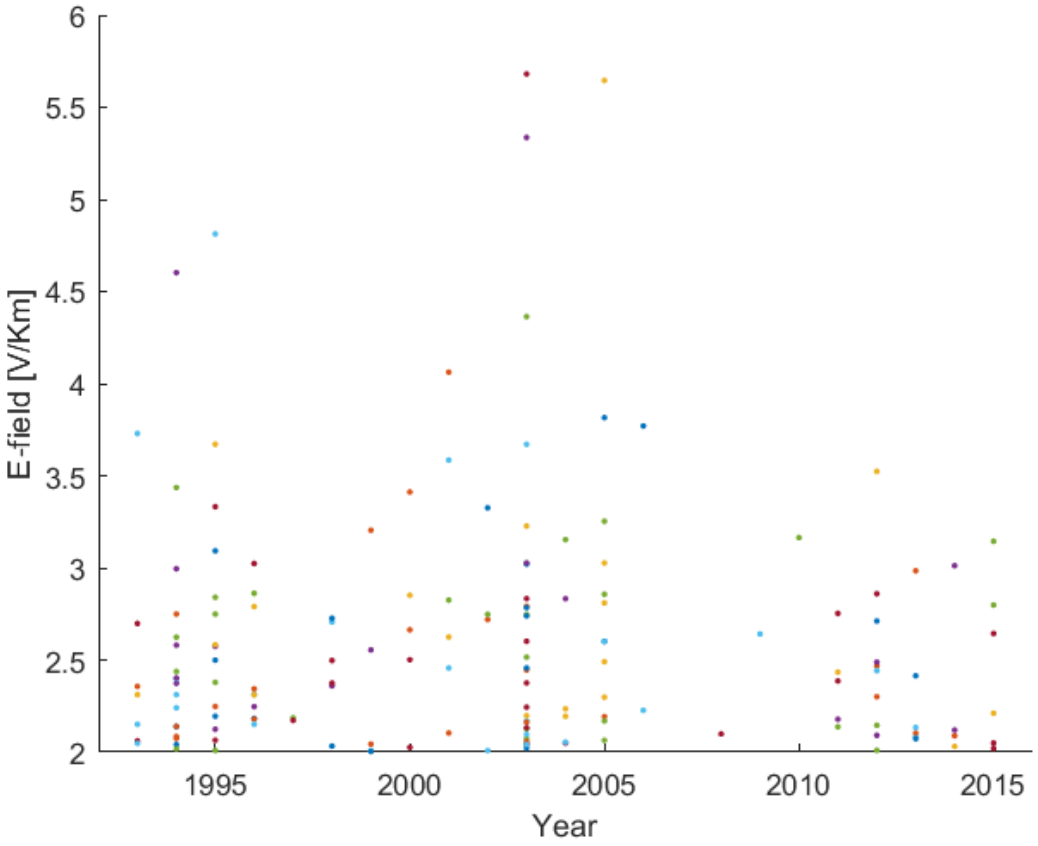


Figure I-1: Scatter Plot of Geoelectric Fields that Exceed a 2 V/km Threshold
Data source: IMAGE magnetometer chain from 1993-2015.

[6] A 95 percent confidence interval means that, if repeated samples were obtained, the return level would lie within the confidence interval for 95 percent of the samples.

Several statistical methods can be used to conduct extreme value analysis. The most commonly applied include: Generalized Extreme Value (GEV), Point Over Threshold (POT), R-Largest, and Point Process (PP). In general, all methods assume independent and identically distributed (iid) data [12].

Table I-1 shows a summary of the estimated parameters and return levels obtained from different statistical methods. The parameters were estimated using the Maximum Likelihood Estimator (MLE). Since the distribution parameters do not have an intuitive interpretation, the expected geoelectric field amplitude for a 100-year return period is also included in **Table I-1**. The 95% confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the Gaussian approximation to the distribution of the MLE; this approximation can be poor for long return periods. In general, the profile likelihood provides a better description of the return level.

Table I-1: Extreme Value Analysis

Statistical Model	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI Delta [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=2.976 (0.193) σ=0.829 (0.1357) ξ=-0.0655 (0.1446)	H0: ξ=0 *p* = 0.66	6.9	[4.3, 8.2]	[5.2, 11.4]
(2) GEV, reparametrization $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0= 2.964 (0.151) β_1=0.582 (0.155) σ=0.627 (0.114) ξ=0.09 (0.183)	H0: β_1=0 *p* = 0.00 H0: ξ=0 *p* = 0.6	7.1	[4, 10.2]	[5.5, 18]
(3) POT, threshold=2 V/km 3 day decluster. 143 observations > 2V/km.	σ=0.592 (0.074) ξ=0.077 (0.093)		6.9	[4.5, 9.4]	[5.4, 11.9]
(4) POT, threshold=2V/km reparametrization, $\sigma = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=0.58 (0.073) β_1=0.107 (0.082) ξ=0.037 (0.097)	H0: B1=0 *p* = 0.2	7	[4.6, 9.3]	[5.5, 11.7]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 23 data points are used in the estimation. The mean expected amplitude of the geoelectric field for a 100-year return level is approximately 7 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure I-1**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a reparametrization of the GEV distribution contemplating the 11-year seasonality in the mean,

$$\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where β_0 represents the offset in the mean, β_1 describes the 11-year seasonality, *T* is the period (11 years), and ϕ is a constant phase shift.

A likelihood ratio test is used to test the hypothesis that β_1 is zero. The null hypothesis, H0: $\beta_1=0$, is rejected with a p-value of 0.0032; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the reparametrized GEV. The mean return level is still 7 V/km, but the confidence interval is wider, [5.5, 18] V/km for the profile likelihood (calculated at solar maximum).

Statistical model (3) in **Table I-1** is the traditional POT estimation using a threshold *u* of 2 V/km; the data was declustered using a 1-day run. The data set consists of normalized excesses over a threshold, and therefore, the sample size for POT is increased if more than one extreme observation per year is available (in the GEV approach, only the maximum observation over the year was taken; in the POT method, a single year can have multiple observations over the threshold). The selection of the threshold *u* is a compromise between bias and variance. The asymptotic basis of the model relies on a high threshold; too low a threshold will likely lead to bias. On the other hand, too high a threshold will reduce the sample size and result in high variance. A threshold of 2V/km was determined to be a good choice, giving rise to 143 observations above the threshold.

The mean return level for statistical model (3), ~7 V/km, is consistent with the GEV estimates. However, due to the larger sample size the POT method is more efficient rendering a confidence interval of [5.4, 11.9] V/km for the profile likelihood method.

In an attempt to cope with potential heteroskedasticity in the data, a reparametrization of POT is proposed in statistical model (4) in **Table I-1**,

$$\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$$

where α_0 represents the offset in the standard deviation, α_1 describes the 11-year seasonality, *T* is the period ($365.25 \cdot 11$), and ϕ is a constant phase shift.

The parameter α_1 is not statistically significant; the null hypothesis, H0: $\alpha_1=0$, is not rejected with a p-value of 0.2. The proposed reparametrization does not have explanatory power, and consequently, the mean return level 7 V/km and confidence intervals remain virtually unchanged [5.5, 11.7]. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method.

Figure I-2 shows the profile likelihood of the 100-year return level of statistical model (3). Note that the profile likelihood is highly asymmetric with a positive skew, rendering a larger upper limit for the confidence interval. Recall that the delta method assumes a normal distribution for the MLEs, and therefore, the confidence interval is symmetric around the mean.

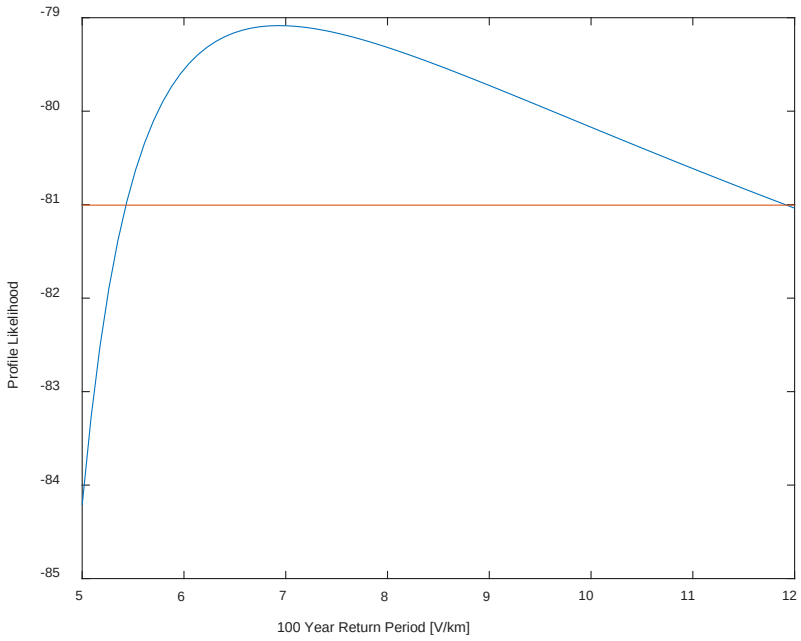


Figure I-2: Profile Likelihood for 100-year Return Level for Statistical Model (3)

To conclude, the traditional GEV (1) is misspecified; the statistical assumptions (iid) are not warranted by the data. The model was reparametrized to cope with seasonality in the data. Statistical models (3) and (4) better utilize the available extreme measurements and they are therefore preferred over statistical model (2). A geoelectric field amplitude of 12 V/km is selected for the supplemental GMD event to represent the upper limit of the 95 percent confidence interval for a 100-year return interval.

Spatial Considerations

The spatial structure of high-latitude geomagnetic fields can be very complex during strong geomagnetic storm events [13]-[14]. One reflection of this spatial complexity is localized geomagnetic field enhancements (local enhancements) that result in high amplitude geoelectric fields in regions of a few hundred kilometers. **Figure I-3** illustrates this spatial complexity of the storm-time geoelectric fields.[7] In areas indicated by the bright red location, the geoelectric field can be substantially larger than at neighboring locations. These enhancements are primarily the result of external (geomagnetic field) conditions, and not local geological factors such as coastal effects.[8]

[7] **Figure I-3** is for illustration purposes only, and is not meant to suggest that a particular area is more likely to experience a localized enhanced geoelectric field. The depiction is not to scale.

[8] Localized externally-driven geomagnetic phenomena should not be confused with localized geoelectric field enhancements due to complex electromagnetic response of the ground to external excitation. Complex 3D geological conditions such as those at coastal regions can lead to localized geoelectric field enhancements but those are not considered here.

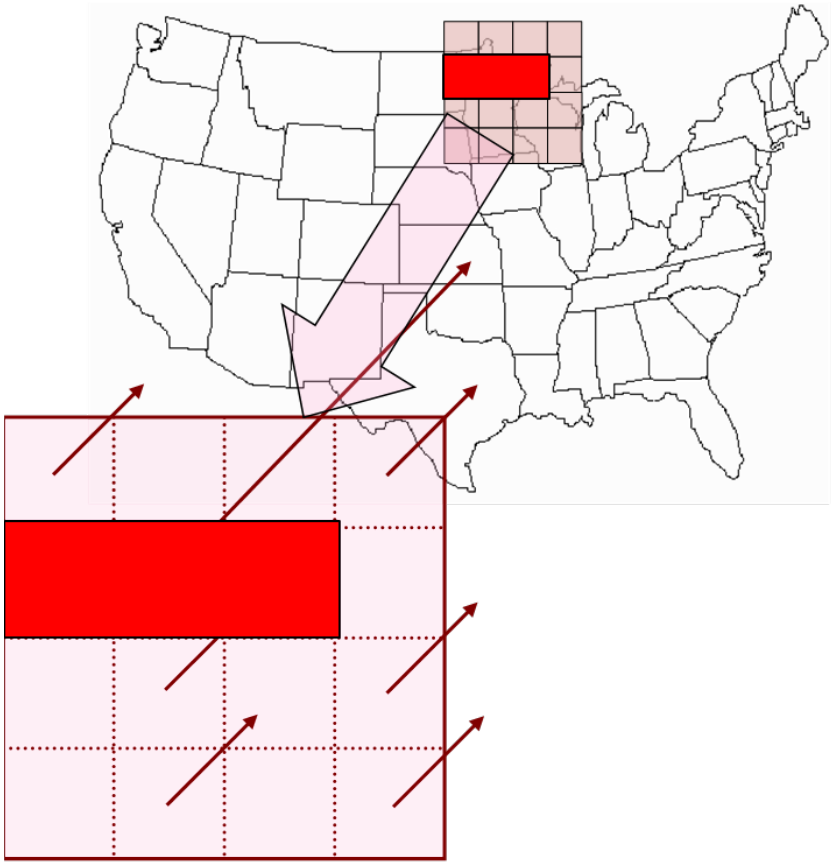


Figure I-3: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field during a Strong Geomagnetic Storm.
In this figure, the red rectangle illustrates a spatially localized field enhancement.

The supplemental GMD event is designed to address local effects caused by a severe GMD event, such as increased var absorption and voltage depressions.

A number of GMD events were analyzed to identify the basic characteristics of local enhancements. Three (3) solar storms studied and described below are:

- March 13, 1989
- October 29-30, 2003
- March 17, 2015

Four localized events within those storms were identified and analyzed. Geomagnetic field recordings were collected for these storms and the geoelectric field was computed using the 1D plane wave method and the reference Quebec ground model. In each case, a local enhancement was correlated, generally oriented parallel to the westward ionospheric electrojet associated with ongoing larger scale geomagnetic activity. (See **Figures I-4 – I-7** below)

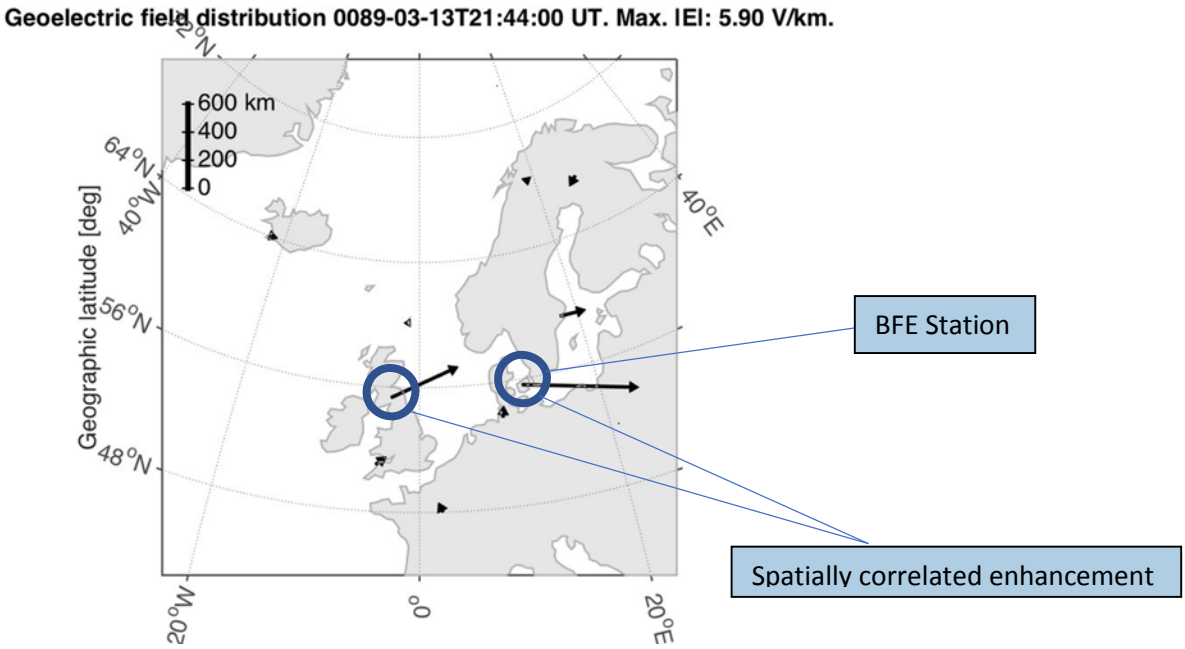


Figure I-4: March 13, 1989, at 21:44 UT, Brorfelde (BFE), Denmark

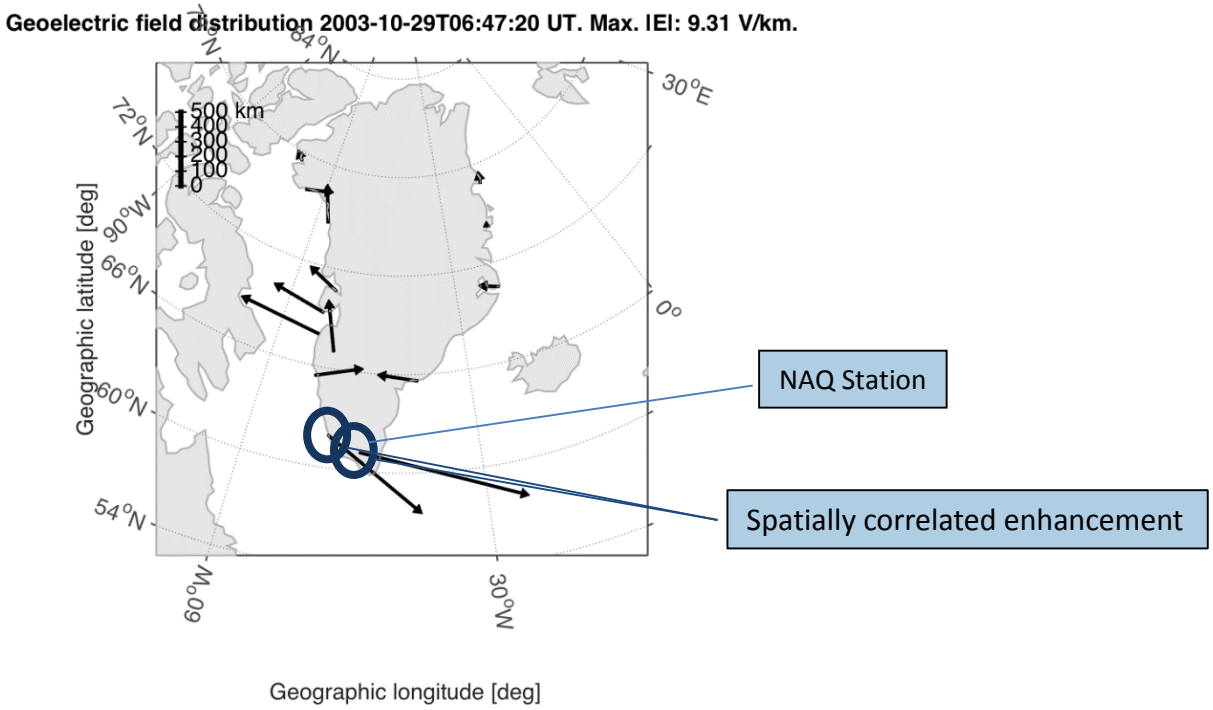


Figure I-5: October 29, 2003, at 06:47 UT, Narsarsuaq (NAQ), Greenland

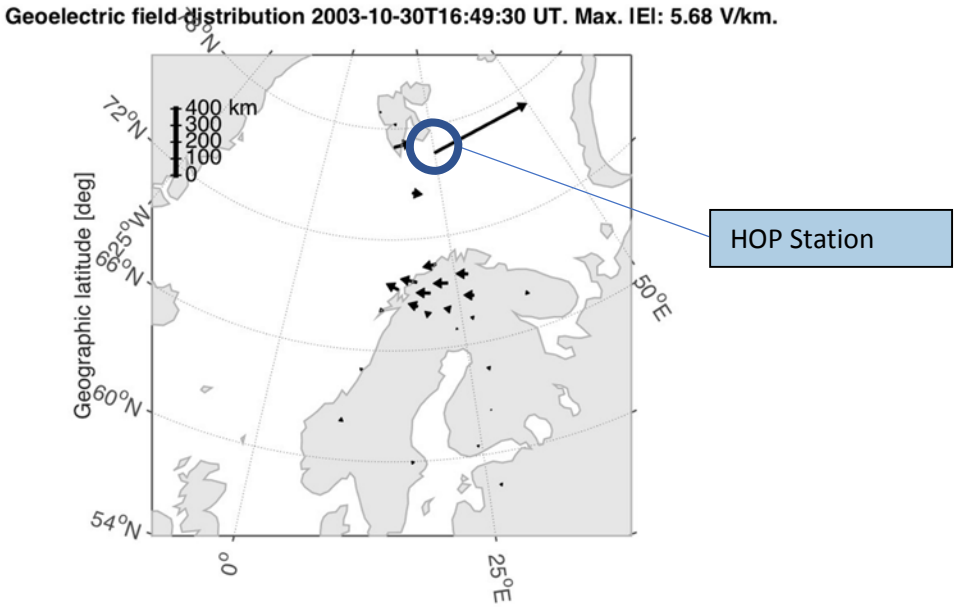


Figure I-6: October 30, 2003, at 16:49UT, Hopen Island (HOP), Svalbard, Norway

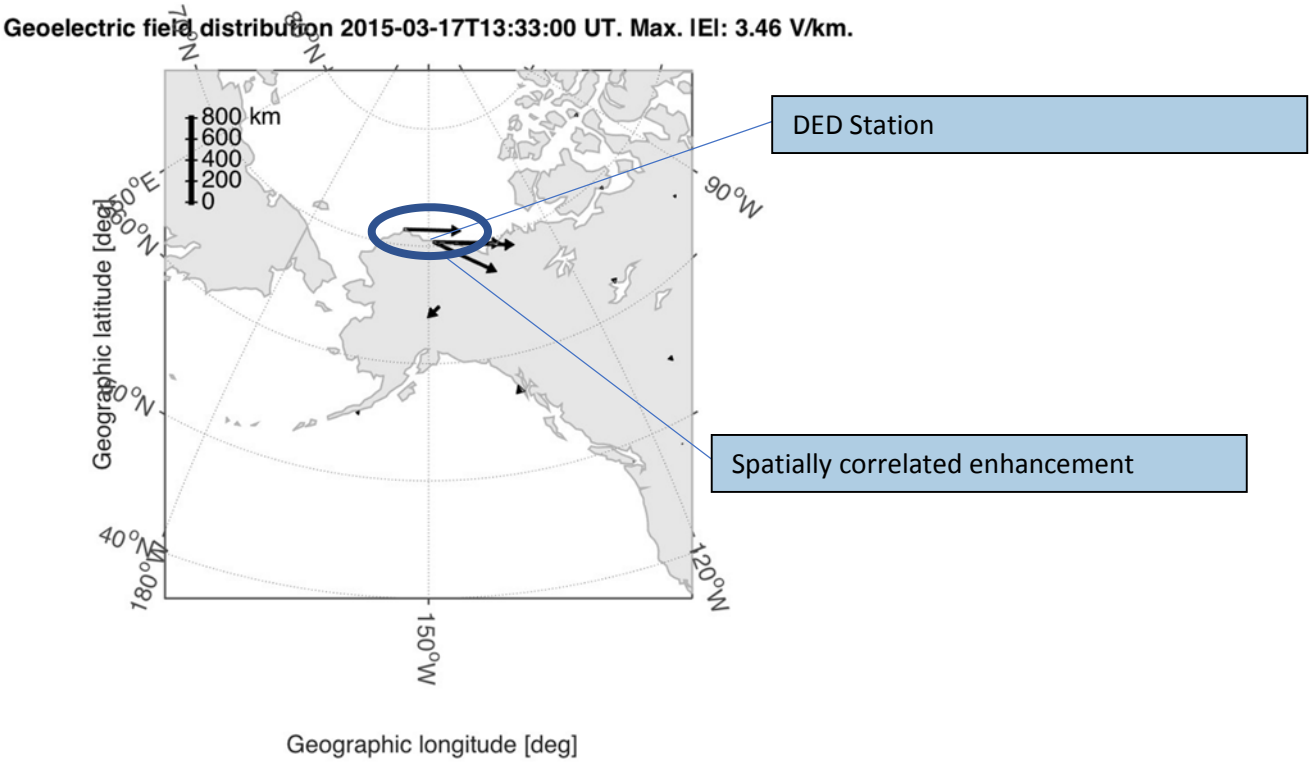


Figure I-7: March 17, 2015, at 13:33 UT, Deadhorse, Alaska

All of the above events were analyzed by reviewing the time series magnetic field data and transforming it to an electric field and focusing on the time period of the spatially correlated local enhancement. There were apparent similarities in the character of the local enhancements. The local enhancements occurred during peak periods of

geomagnetic activity and were distinguished by relatively brief excursions of rapid magnetic field variation. With respect to time duration, the local enhancements generally occurred over a period of 2-5 minutes. (See **Figures I-8 – I-11**)

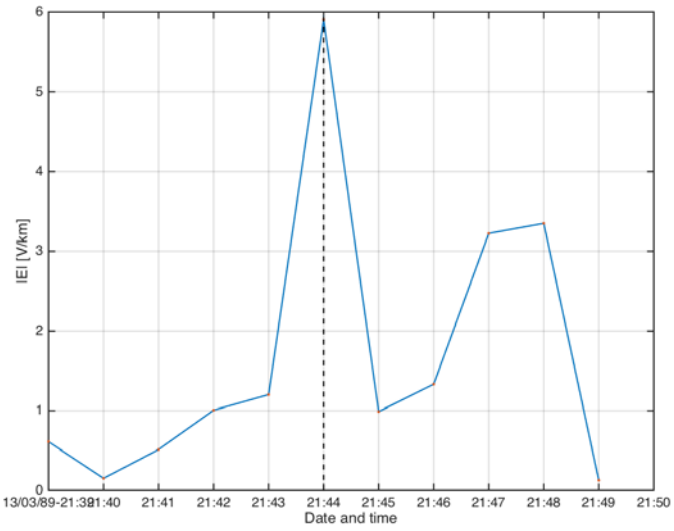


Figure I-8: Geoelectric field March 13, 1989, at 21:44 UT, Brorfelde (BFE), Denmark.

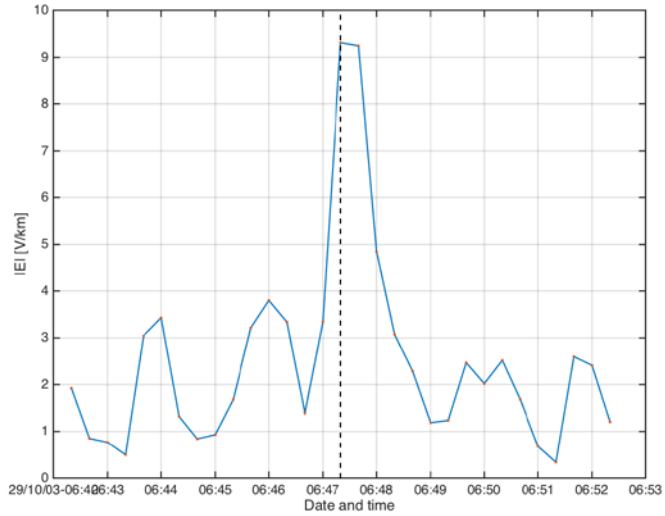


Figure I-9: Geoelectric field October 29, 2003, at 06:47 UT, Narsarsuaq (NAQ), Greenland

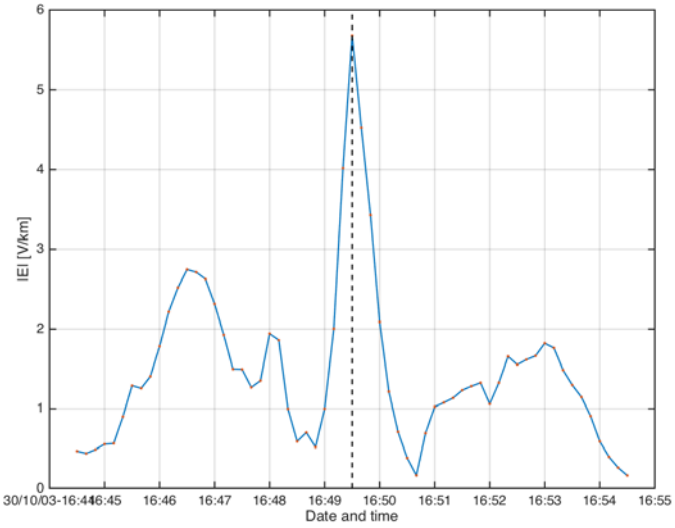


Figure I-10: Geoelectric field October 30, 2003, at 16:49UT, Hopen Island (HOP), Norway

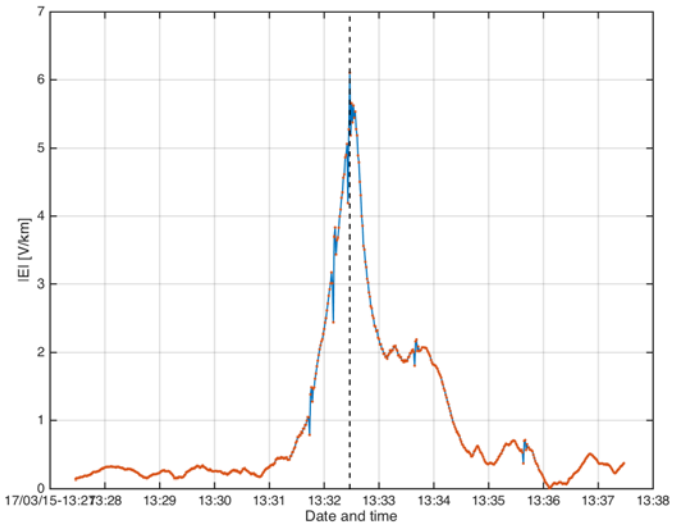


Figure I-11 – Geoelectric field March 17, 2015, at 13:33 UT, Deadhorse, Alaska

Based 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 to account for the potential impact of a local enhancement in both the network analysis and the transformer thermal assessment(s).

With respect to geographic area of the localized enhancement, the historical geomagnetic field data analyzed so far provides some insight. Analysis suggests that the enhancements will occur in a relatively narrow band of geomagnetic latitude (on the order of 100 km) and wider longitudinal width (on the order of 500 km) as a consequence of the westward-oriented structure of the source in the ionosphere.

Proposed TPL-007-2 provides flexibility for planners to determine how to apply the supplemental GMD event to the planning area. Acceptable approaches include but are not limited to:

- Apply the peak geoelectric field for the supplemental GMD event (12 V/km scaled to the planning area) over the entire planning area;

- Apply a spatially limited (e.g., 100 km in North-South direction and 500 km in East-West direction) geoelectric field enhancement (12 V/km scaled to the planning area) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system.
- Other methods to adjust the benchmark GMD event analysis for localized geoelectric field enhancement.

Given 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.

Local Enhancement Waveform

The supplemental geomagnetic field waveform was derived by modifying the benchmark GMD event waveform to emulate the observed events described above. The temporal location of the enhancement corresponds to the time of the benchmark event with the highest geoelectric field. The local enhancement was constructed by scaling linearly a 5-minute portion of the benchmark geomagnetic field so that the peak geoelectric field is 12 V/km at a geomagnetic latitude of 60° and reference earth model. **Figure I-12** shows the benchmark geomagnetic field and **Figure I-13** shows the supplemental event geomagnetic field. **Figure I-14** expands the view into B_x, with and without the local enhancement. **Figure I-15** is the corresponding expanded view of the geoelectric field magnitude with and without the local enhancement.

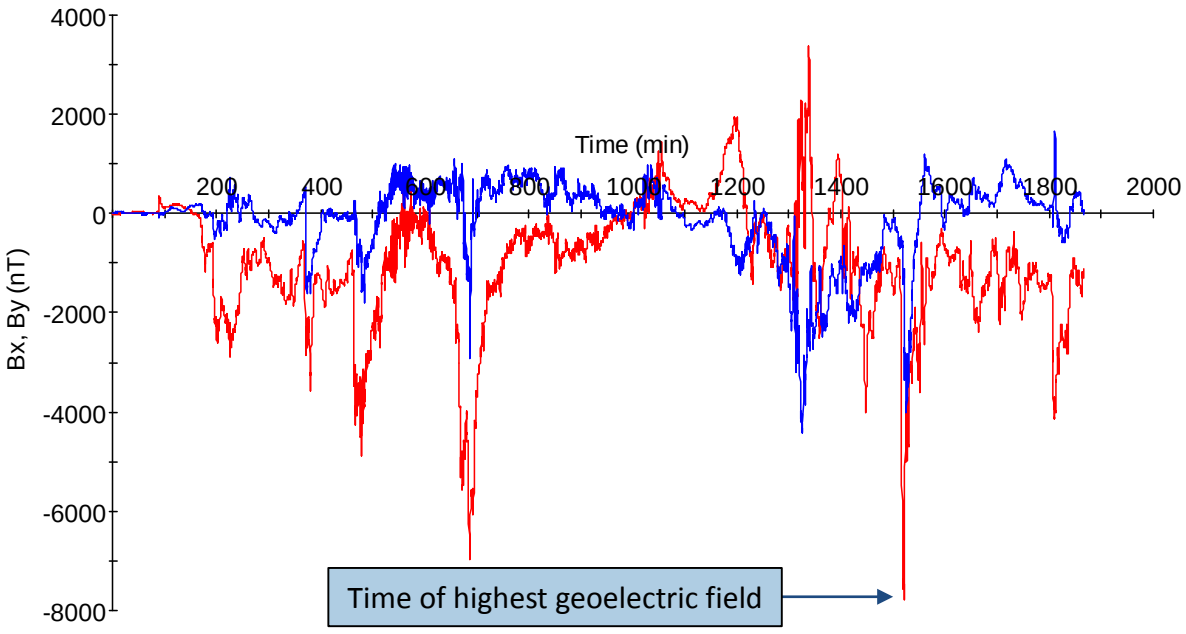


Figure I-12: Benchmark Geomagnetic Field. Red B_x (Northward), Blue B_y (Eastward)

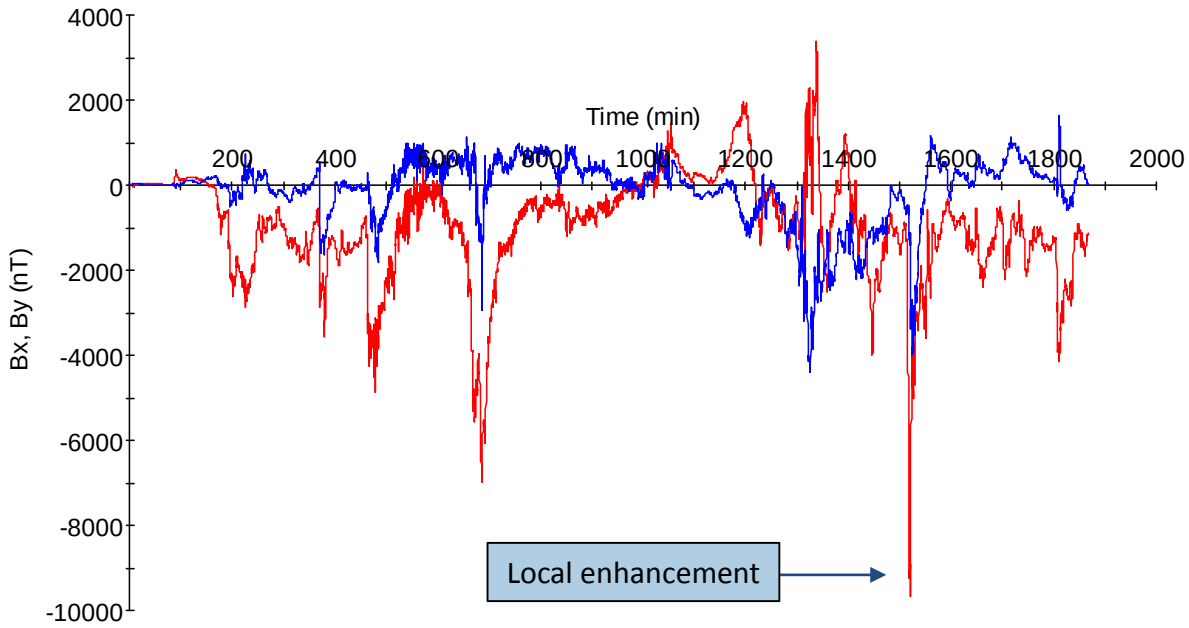


Figure I-13: Supplemental Geomagnetic Field Waveform. Red B_x (Northward), Blue B_y (Eastward)

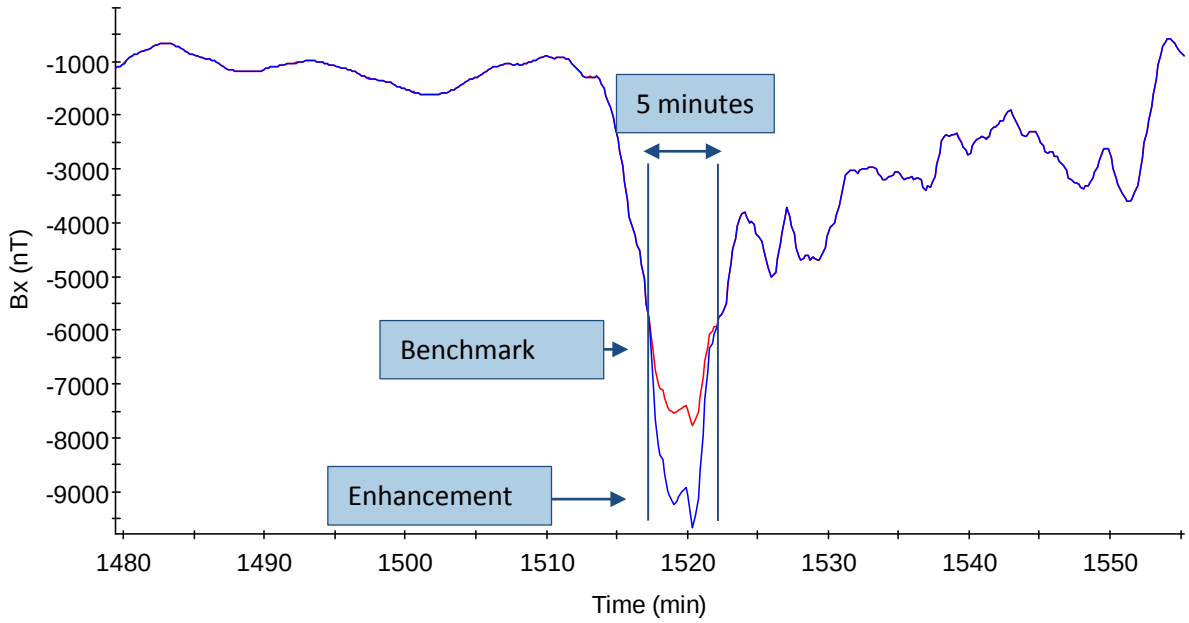


Figure I-14: Red Benchmark B_x and Blue Supplemental B_x (Northward) – Expanded View

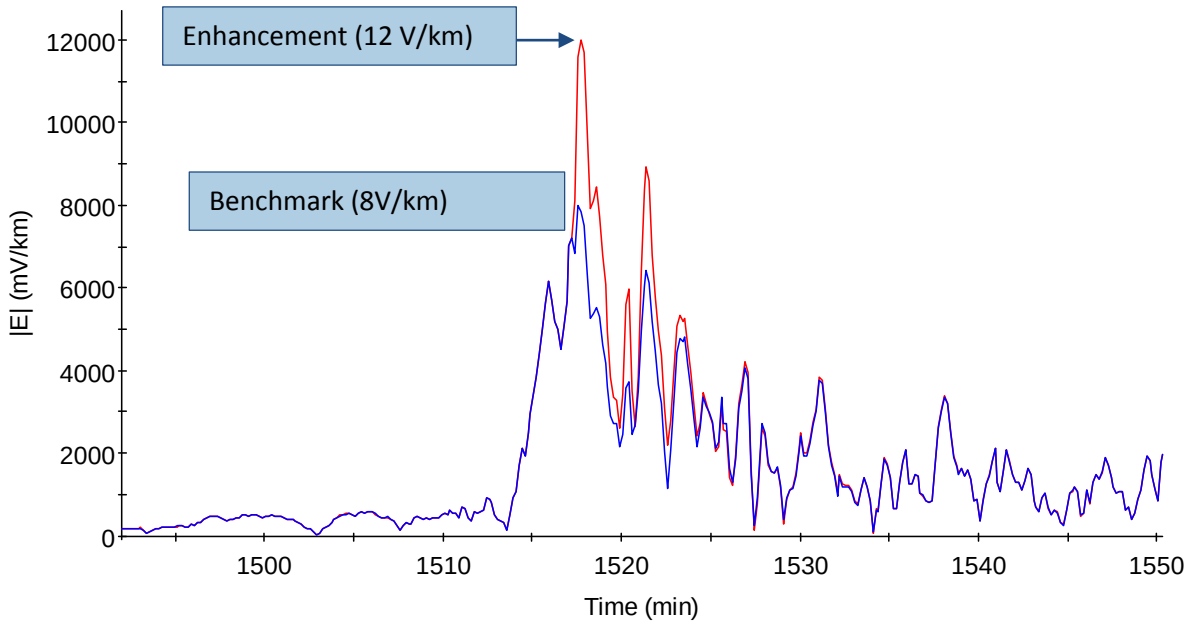


Figure I-15: Magnitude of the Geoelectric Field. Benchmark Blue and Supplemental Red – Expanded View

Transformer Thermal Assessment

The local enhancement of the supplemental GMD event waveform can have a material impact on the temperature rise (hot-spot heating or metallic parts) even though the duration of the local enhancement is approximately 5 minutes. Thermal assessments based on the supplemental GMD event can be performed using the same methods employed for benchmark thermal assessments.[9]

[9] See Transformer Thermal Impact Assessment white paper: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Appendix II – Scaling the Supplemental GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude and local earth conductivity [2].[10] Scaling factors for geomagnetic latitude take into consideration that the intensity of a GMD event varies according to latitude-based geographical location. Scaling factors for earth conductivity take into account that the induced geoelectric field depends on earth conductivity, and that different parts of the continent have different earth conductivity and deep earth structure.

Scaling the supplemental GMD event differs from the benchmark GMD event in two ways:

- E_{peak} is 12 V/km instead of 8 V/km
- Beta factors for scaling the geoelectric field based on earth conductivity are different (see **Table II-2**)

More discussion, including example calculations, is contained in the Benchmark GMD Event Description white paper.

Scaling the Geomagnetic Field

The supplemental GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. To allow usage of the supplemental geomagnetic field waveform in other locations, **Table II-1** summarizes the scaling factor α correlating peak geoelectric field to geomagnetic latitude as described in **Figure II-1** [3]. This scaling factor α has been obtained from a large number of global geomagnetic field observations of all major geomagnetic storms since the late 1980s [15]-[27], and can be approximated with the empirical expression in (II.1)

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \qquad \text{(II.1)}$$

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1.0$.

[10] Geomagnetic latitude is analogous to geographic latitude, except that bearing is in relation to the magnetic poles, as opposed to the geographic poles. Geomagnetic phenomena are often best organized as a function of geomagnetic coordinates. Local earth conductivity refers to the electrical characteristics to depths of hundreds of km down to the earth's mantle. In general terms, lower ground conductivity results in higher geoelectric field amplitudes.

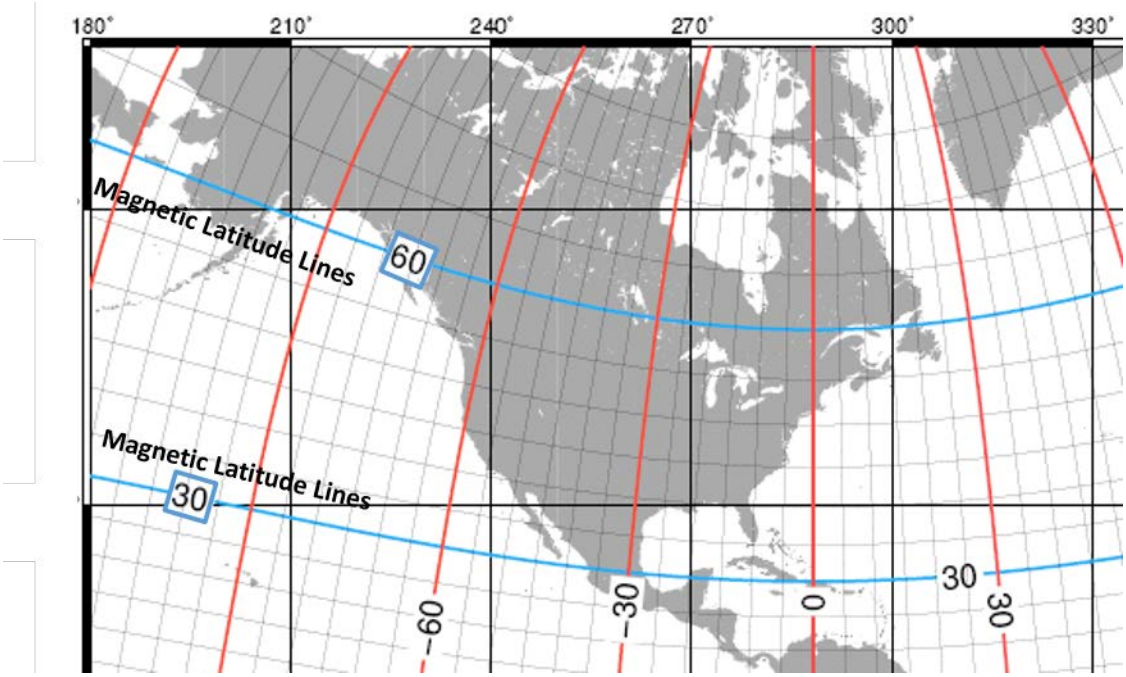


Figure II-1: Geomagnetic Latitude Lines in North America

Table II-1: Geomagnetic Field Scaling Factors

Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The supplemental GMD event is defined for the reference Quebec earth model provided in **Table 1**. This earth model has been used in many peer-reviewed technical articles [11, 15]. The peak geoelectric field depends on the geomagnetic field waveform and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic field waveform using the plane wave method and taking the maximum value of the resulting waveforms

$$E_N = (z(t)/\mu_o) * B_E(t)$$
$$E_E = -(z(t)/\mu_o) * B_N(t) \quad \text{(II.2)}$$
$$E_{peak} = \max\left\{\left|E_E(t), E_N(t)\right|\right\}$$

where,

* denotes convolution in the time domain,

z(t) is the impulse response for the earth surface impedance calculated from the laterally uniform or 1D earth model,

$B_E(t)$, $B_N(t)$ are the scaled Eastward and Northward geomagnetic field waveforms,

$E_E(t)$, $E_N(t)|$ are the magnitudes of the calculated Eastward and Northward geoelectric field $E_E(t)$ and $E_N(t)$.

As noted previously, the response of the earth to B(t) (and dB/dt) is frequency dependent. **Figure II-2** shows the magnitude of Z(ω) for the reference earth model.

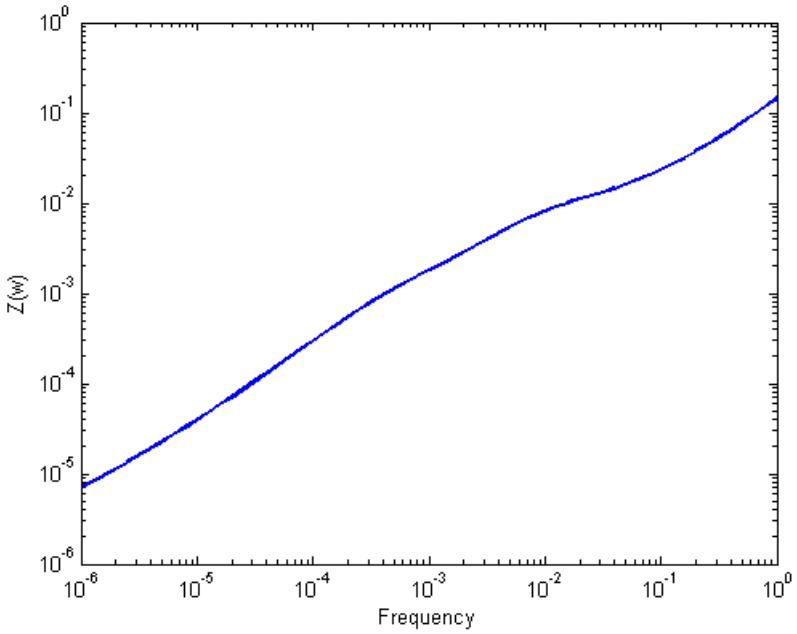


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

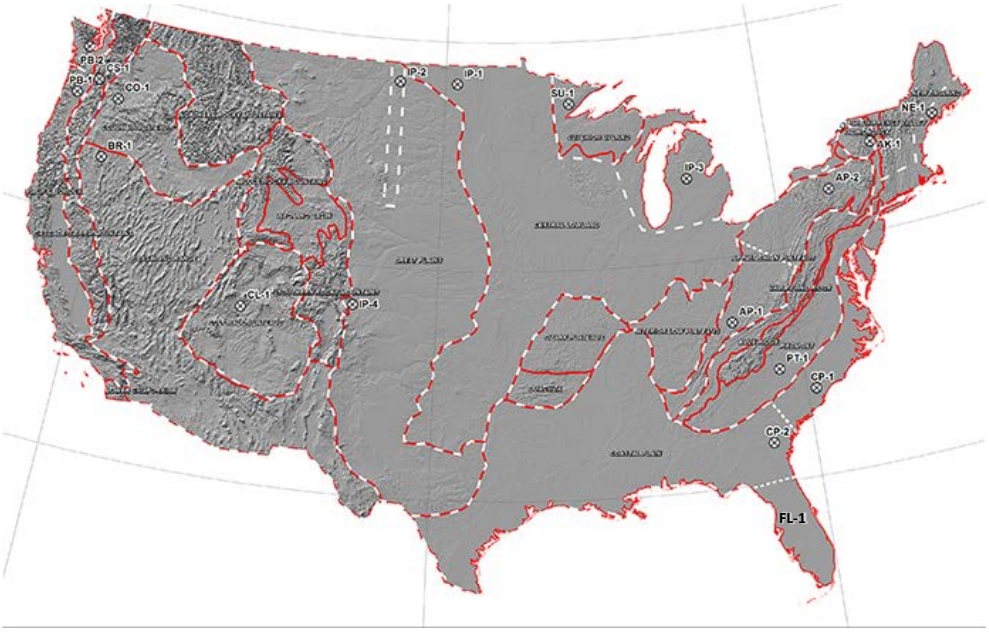
If a utility does not have the capability of calculating the waveform or time series for the geoelectric field, an earth conductivity scaling factor β_S can be obtained from **Table II-2**. Using α and β, the peak geoelectric field E_{peak} for a specific service territory shown in **Figure II-3** can be obtained using (II.3)

$$E_{peak}\ 12 \times \alpha \times \beta_s \ (\text{V/km}) \quad \text{(II.3)}$$

It should be noted that (II.3) is an approximation based on the following assumptions:

- The earth models used to calculate Table II-2 for the United States are from published information available on the USGS website. These scaling factors are slightly lower than the ones in the benchmark because the supplemental benchmark waveform has a higher frequency content at the time of the local enhancement.
- The models used to calculate Table II-2 for Canada were obtained from NRCan and reflect the average structure for large regions. When models are developed for sub-regions, there will be variance (to a greater or lesser degree) from the average model. For instance, detailed models for Ontario have been developed by NRCan and consist of seven major sub-regions.
- The conductivity scaling factor β_S is calculated as the quotient of the local geoelectric field peak amplitude in a physiographic region with respect to the reference peak amplitude value of 12 V/km. Both geoelectric field peak amplitudes are calculated using the supplemental geomagnetic field time series. If a different geomagnetic field time series were used, the calculated scaling factors (β) would be different than the values in Table II-2 because the frequency content of storm maxima is, in principle, different for every storm. If a utility has technically-sound earth models for its service territory and sub-regions thereof, then the use of such earth models is preferable to estimate E_{peak}.
- When a ground conductivity model is not available the planning entity should use the largest β_s factor of adjacent physiographic regions or a technically-justified value.

Physiographic Regions of the Continental United States



Physiographic Regions of Canada

Figure II-3: Physiographic Regions of North America

Table II-2 Supplemental Geoelectric Field Scaling Factors	
Earth model	**Scaling Factor (β)**
AK1A	0.51
AK1B	0.51
AP1	0.30
AP2	0.78
BR1	0.22
CL1	0.73
CO1	0.25
CP1	0.77
CP2	0.86
FL1	0.73
CS1	0.37
IP1	0.90
IP2	0.25
IP3	0.90
IP4	0.35
NE1	0.77
PB1	0.55
PB2	0.39
PT1	1.19
SL1	0.49
SU1	0.90
BOU	0.24
FBK	0.56
PRU	0.22
BC	0.62
PRAIRIES	0.88
SHIELD	1.0
ATLANTIC	0.76

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transformer Thermal Impact Assessment White Paper

~~Project 2013-03 (Geomagnetic Disturbance Mitigation)~~

TPL-007-~~1~~2~~–~~Transmission System Planned Performance for Geomagnetic Disturbance Events

Background

~~On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances (GMDs) in two stages:~~

- ~~Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.~~
- ~~Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.~~

~~TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779.~~

~~Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-1 will require owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers will be able to withstand the thermal transient effects associated with the Benchmark GMD event. This paper discusses methods that can be employed to conduct such analyses, including example calculations.~~

Proposed TPL-007-2 includes requirements for entities to perform two types of GMD Vulnerability Assessments to evaluate the potential impacts of GMD events on the Bulk Electric System (BES):

- The benchmark GMD Vulnerability Assessment is based on the benchmark GMD event associated with TPL-007-1 which was approved by the Federal Energy Regulatory Commission (FERC) in Order No. 830 in September 2016. The benchmark GMD event is derived from spatially-averaged geoelectric field values to address potential wide-area effects that could be caused by a severe 1-in-100 year GMD event.[1]
- The supplemental GMD Vulnerability Assessment, based on the supplemental GMD event, is used by entities to evaluate localized peaks in geomagnetic field during a severe GMD event that "could

[1] See *Benchmark Geomagnetic Disturbance Event Description* white paper, May 12, 2016. Filed by NERC in RM15-11 on June 28, 2016.

potentially affect the reliable operation of the Bulk-Power System."[2] Localized enhancements of geomagnetic field can result in geoelectric field values above the spatially-averaged benchmark in a local area.

The standard requires transformer thermal impact assessments to be performed on BES power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-2 requires owners of such BES transformers to conduct thermal analyses to determine if the BES transformers will be able to withstand the thermal transient effects associated with the GMD events. BES Transformers must undergo a thermal impact assessment if the maximum effective geomagnetically-induced current (GIC) in the transformer is equal to or greater than:[3]

- 75 A per phase for the benchmark GMD event
- 85 A per phase for the supplemental GMD event

This white paper discusses methods that can be employed to conduct transformer thermal impact assessments, including example calculations. The first version of the white paper was developed by the Project 2013-03 GMD Standards Drafting Team (SDT) for TPL-007-1 and was endorsed by the Electric Reliability Organization (ERO) as implementation guidance in October 2016. The SDT has updated the white paper to include the supplemental GMD event that is added in TPL-007-2 to address directives in FERC Order No. 830.

The primary impact of GMDs on large power transformers is a result of the quasi-dc current that flows through wye-grounded transformer windings. This geomagnetically-induced current (GIC) results in an offset of the ac sinusoidal flux resulting in asymmetric or half-cycle saturation (see **Figure 1**).

Half-cycle saturation results in a number of known effects:

- Hot spot heating of transformer windings due to harmonics and stray flux;
- Hot spot heating of non-current carrying transformer metallic members due to stray flux;
- Harmonics;
- Increase in reactive power absorption; and
- Increase in vibration and noise level.

[2] See Order No. 830 P. 47. On September 22, 2016, FERC directed NERC to develop modifications to the benchmark GMD event, included in TPL-007-1, such that assessments would not be based solely on spatially averaged data. The characteristics of a GMD event for this assessment are in the Supplemental GMD Event Description white paper.

[3] See *Screening Criterion for Transformer Thermal Impact Assessment* for technical justification.

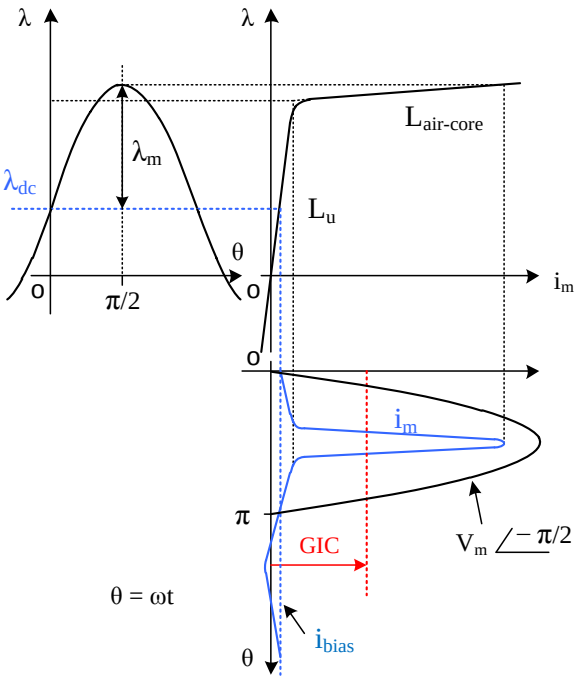


Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

This paper focuses on hot spot heating of transformer windings and non current-carrying metallic parts. Effects such as the generation of harmonics, increase in reactive power absorption, vibration, and noise are not within the scope of this document.

Technical Considerations

The effects of half-cycle saturation on HV and EHV transformers, namely localized "hot spot" heating, are relatively well understood, but are difficult to quantify. A transformer GMD impact assessment must consider GIC amplitude, duration, and transformer physical characteristics such as design and condition (e.g., age, gas content, and moisture in the oil). A single threshold value of GIC cannot be justified as a "pass or fail" screening criterion where "fail" means that the transformer will suffer damage. A single threshold value of GIC only makes sense in the context where "fail" means that a more detailed study is required ~~and that "pass" means that GIC in a particular transformer is so low that a detailed study is unnecessary.~~. Such a threshold would have to be technically justifiable and sufficiently low to be considered a conservative value ~~within the scope of the benchmark.~~of GIC.

The following considerations should be taken into account when assessing the thermal susceptibility of a transformer to half-cycle saturation:

- In the absence of manufacturer specific information, use the temperature limits for safe transformer operation such as those suggested in the IEEE Std C57.91-2011 ~~standard [1]~~(IEEE Guide for Loading Mineral-oil-immersed Transformers and Step-voltage Regulators) for hot spot heating during short-

term emergency operation. [1]. This standard does not suggest that exceeding these limits will result in transformer failure, but rather that it will result in additional aging of cellulose in the paper-oil insulation and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of evaluating possible transformer damage due to increased hot spot heating, these thresholds can be considered conservative for a transformer in good operational condition.

- The worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).
- Bulk oil temperature due to ambient temperature and transformer loading must be added to the incremental temperature rise caused by hot spot heating. For planning purposes, maximum ambient and loading temperature should be used unless there is a technically justified reason to do otherwise.
- The time series or "waveshapewaveform" of the reference GMD event in terms of peak amplitude, duration, and frequency of the geoelectric field has an important effect on hot spot heating. Winding and metallic part hot spot heating have different thermal time constants, and their temperature rise will be different if the GIC currents are sustained for 2, 10, or 30 minutes for a given GIC peak amplitude.
- The "effective" GIC in autotransformers (reflecting the different GIC ampere-turns in the common and the series windings) must be used in the assessment. The effective current $I_{dc,eq}$ in an autotransformer is defined by [2].

$$I_{dc,eq} = I_H + (I_N/3 - I_H)V_X/V_H \quad (1)$$

where

I_H is the dc current in the high voltage winding;
I_N is the neutral dc current;
V_H is the rms rated voltage at HV terminals;
V_X is the rms rated voltage at the LV terminals.

Transformer Thermal Impact Assessment Process

A simplified thermal assessment may be based on Table 2the appropriate tables from the "Screening Criterion for Transformer Thermal Impact Assessment" white paper [7]. This3].[4] Each table, shown as Table 1 below, provides the peak metallic hot spot temperatures that can be reached for the given GMD event using conservative thermal models. To use Table 1each table, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after

[4] Table 1 in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper provides upper bound temperatures for the benchmark GMD event. Table 2 in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper provides upper bound temperatures for the supplemental GMD event.

allowing for possible de-rating due to transformer condition. If the effective GIC results in higher than threshold temperatures, then the use of a detailed thermal assessment as described below should be carried out.[5]

Table 1: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event

Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC (A/phase)	Metallic hot spot Temperature (°C)
0	80	100	182
10	107	110	186
20	128	120	190
30	139	130	193
40	148	140	204
50	157	150	213
60	169	160	221
70	170	170	230
75	172	180	234
80	175	190	241
90	179	200	247

Table 2: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Supplemental GMD Event

Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	120	188
10	107	130	191
20	124	140	194
30	137	150	198
40	147	160	203
50	156	170	209
60	161	180	214
70	162	190	229
75	165	200	237
80	169	220	248
85	172	230	253

[5] Effective GIC in the table is the peak GIC(t) for the GMD event being assessed. Peak GIC(t) is not steady-state GIC.

90	177	250	276
100	181	275	298
110	185	300	316

Two different ways to carry out a detailed thermal impact assessment are discussed below. In addition, other approaches and models approved by international standard-setting organizations such as the Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE) may also provide technically justified methods for performing thermal assessments.[6] All thermal assessment methods should be demonstrably equivalent to assessments that use the ~~benchmark GMD event.~~GMD events associated with TPL-007-2.

1. Transformer manufacturer GIC capability curves. These curves relate permissible peak GIC (obtained by the user from a steady-state GIC calculation) and loading, for a specific transformer. An example of manufacturer capability curves is provided in **Figure 2**. Presentation details vary between manufacturers, and limited information is available regarding the assumptions used to generate these curves, in particular, the assumed waveshape or duration of the effective GIC. Some manufacturers assume that the ~~waveshape~~waveform of the GIC in the transformer windings is a square pulse of 2, 10, or 30 minutes in duration. In the case of the transformer capability curve shown in **Figure 2** ~~[3],~~ a square pulse of 900 A/phase with a duration of 2 minutes would cause the Flitch plate hot spot to reach a temperature of 180~~°~~°C at full load~~.~~ [5]. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC ~~waveshape~~waveform is equivalent to, for example, a 2 minute pulse. Also, manufacturers generally maintain that in the absence of transformer standards defining thermal duty due to GIC, such capability curves must be developed for every transformer design and vintage.

[6] For example, C57.163-2015 – IEEE Guide for Establishing Power Transformer Capability while under Geomagnetic Disturbances. [4]

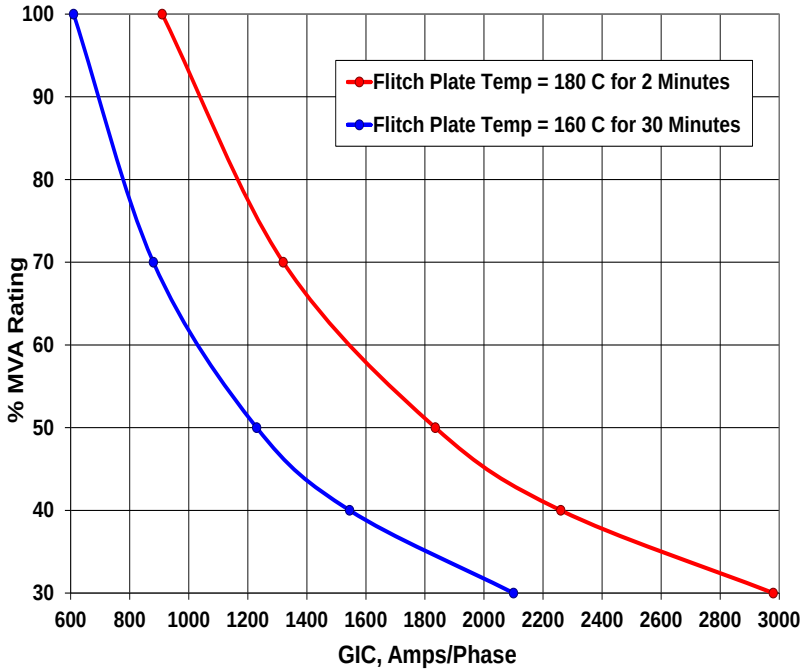


Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [~~3~~35]

2. Thermal response simulation.[7] ~~.~~ The input to this type of simulation is the time series or ~~waveshape~~waveform of effective GIC flowing through a transformer (taking into account the actual configuration of the system), and the result of the simulation is the hot spot temperature (winding or metallic part) time sequence for a given transformer. An example of GIC input and hotspot temperature time series values from [~~4~~46] are shown in **Figure 3**. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers. Conservative default values can be used (e.g~~.~~., those provided in [~~4~~46]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std C57.91-2011 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[7] Technical details of this methodology can be found in [~~4~~46].

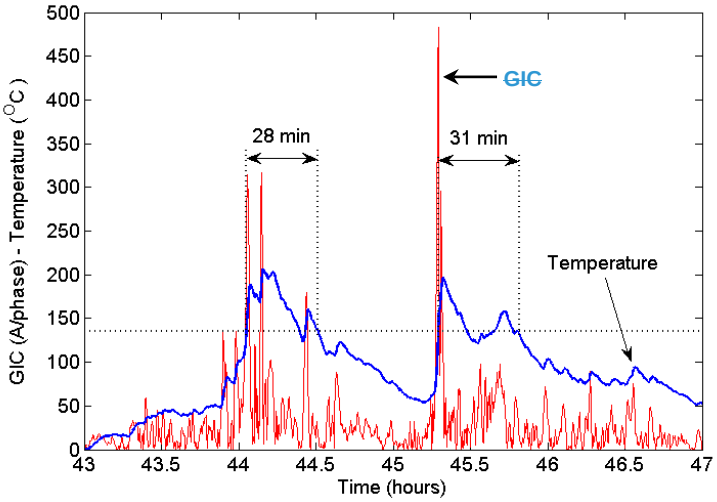


Figure 3: Sample Tie Plate Temperature Calculation
Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [~~4~~] 6]

It is important to reiterate that the characteristics of the time sequence or "~~waveshape~~waveform" are very important in the assessment of the thermal impact of GIC on transformers. Transformer hot spot heating is not instantaneous. The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes; therefore, hot spot temperatures are heavily dependent on GIC history and rise time, amplitude and duration of GIC in the transformer windings, bulk oil temperature due to loading, ambient temperature and cooling mode.

Calculation of the GIC ~~Waveshape~~Waveform for a Transformer

The following procedure can be used to generate time series GIC data~~,~~ (i.e~~.,~~ GIC(t~~,~~)) using a software program capable of computing GIC in the steady-state. The steps are as follows:

1. Calculate contribution of GIC due to eastward and northward geoelectric fields for the transformer under consideration;
2. Scale the GIC contribution according to the reference geoelectric field time series to produce the GIC time series for the transformer under consideration.

Most available GIC–capable software packages can calculate GIC in steady-state in a transformer assuming a uniform eastward geoelectric field of 1 V/km (GIC_E) while the northward geoelectric field is zero. Similarly, GIC_N can be obtained for a uniform northward geoelectric field of 1 V/km while the eastward geoelectric field is zero. GIC_E and GIC_N are the normalized GIC contributions for the transformer under consideration.

If the earth conductivity is assumed to be uniform (or laterally uniform) in the transmission system of interest, then the transformer GIC (in A/phase) for any value of $E_E(t)$ and $E_N(t)$ can be calculated using (2) [2].

$$GIC(t) = |E(t)| \cdot \{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\} \quad (2)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \quad (3)$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \quad (4)$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \quad (5)$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km. The units for GIC_N and GIC_E are A/phase~~/~~ per V/km)

The geoelectric field time series $E_N(t)$ and $E_E(t)$ is obtained, for instance, from the reference geomagnetic field time series ~~[5]~~(from [7] and/or [8]) after the appropriate geomagnetic latitude scaling factor α is applied.[8] ~~.~~ The reference geoelectric field time series is calculated using the reference earth model. When using this geoelectric field time series where a different earth model is applicable, it should be scaled with the appropriate conductivity scaling factor ~~ββ.~~[9] ~~.~~ Alternatively, the geoelectric field can be calculated from the reference geomagnetic field time series after the appropriate geomagnetic latitude scaling factor α is applied and the appropriate earth model is used. In such case, the conductivity scaling factor β is not applied because it is already accounted for by the use of the appropriate earth model.

Applying (5) to each point in $E_N(t)$ and $E_E(t)$ results in GIC(t).

GIC(t) Calculation Example

Let us assume that from the steady-state solution, the effective GIC in this transformer is GIC_E = -20 A/phase if E_N=0, E_E=1 V/km and GIC_N = 26 A/phase if E_N=1 V/km, E_E=0. Let us also assume the geomagnetic field time series corresponds to a geomagnetic latitude where α = 1 and that the earth conductivity corresponds to the reference earth model in [~~5~~7]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)} \quad (6)$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)} \quad (7)$$

[8] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator), the lower the amplitude of the geomagnetic field.

[9] The conductivity scaling factor β is described in [2], and is used to scale the geoelectric field according to the conductivity of different physiographic regions. Lower conductivity results in higher β scaling factors.

The resulting GIC ~~waveshape~~waveform GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

It should be emphasized that even for the same reference event, the GIC(t) ~~waveshape~~waveform in every transformer will be different, depending on the location within the system and the number and orientation of the circuits connecting to the transformer station. Assuming a single generic GIC(t) ~~waveshape~~waveform to test all transformers is incorrect.

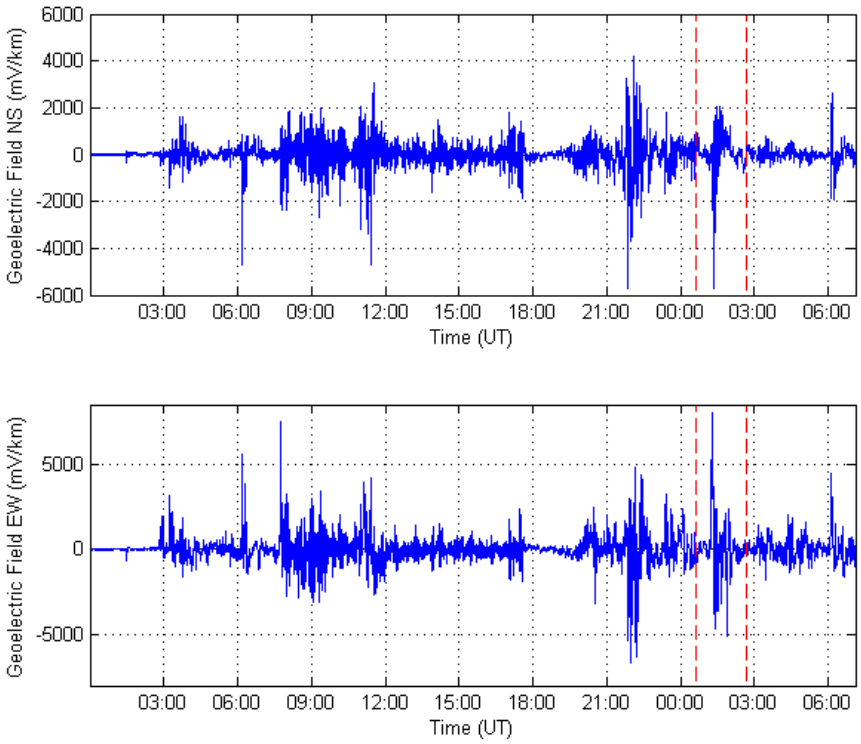


Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model).
Zoom area for subsequent graphs is highlighted.
Dashed lines approximately show the close-up area for subsequent Figures.

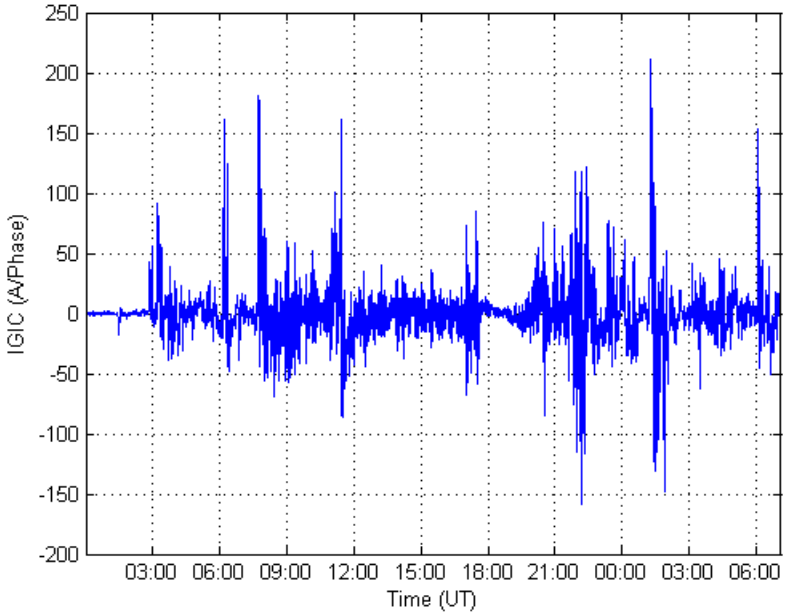


Figure 5: Calculated GIC(t) Assuming $\alpha=1$ and $\beta=1$
{Reference Earth Model}

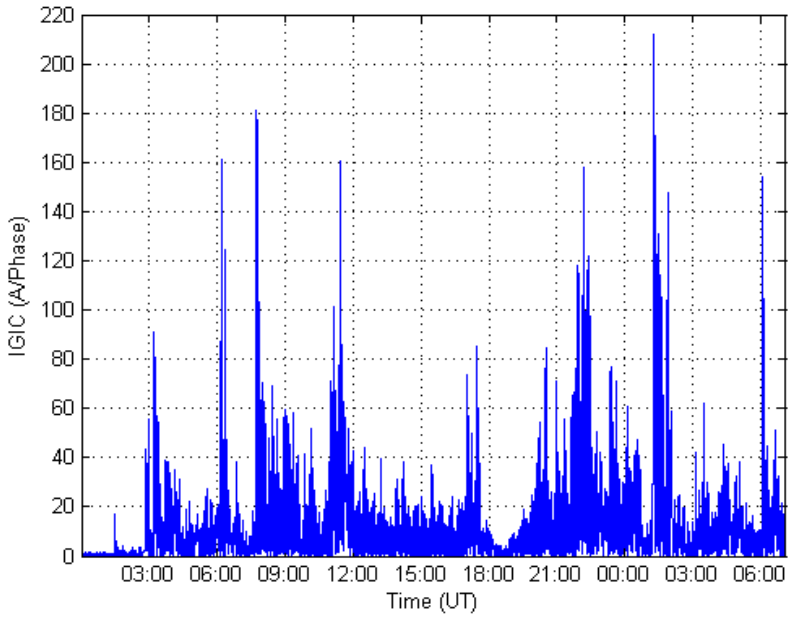


Figure 6: Calculated Magnitude of GIC(t) Assuming $\alpha=1$ and $\beta=1$
{Reference Earth Model}

Transformer Thermal Assessment Examples

There are two basic ways to carry out a transformer thermal analysis once the GIC time series GIC(t) is known for a given transformer: 1) calculating the thermal response as a function of time; and 2) using manufacturer's capability curves.

Example 1: Calculating thermal response as a function of time using a thermal response tool

The thermal step response of the transformer can be obtained for both winding and metallic part hot spots from: 1) measurements; 2) manufacturer's calculations; or 3) generic published values. **Figure 7** shows the measured metallic hot spot thermal response to a dc step of 16.67 A/phase of the top yoke clamp from [~~6~~9] that will be used in this example. **Figure 8** shows the measured incremental temperature rise (asymptotic response) of the same hot spot to long duration GIC steps.[10]

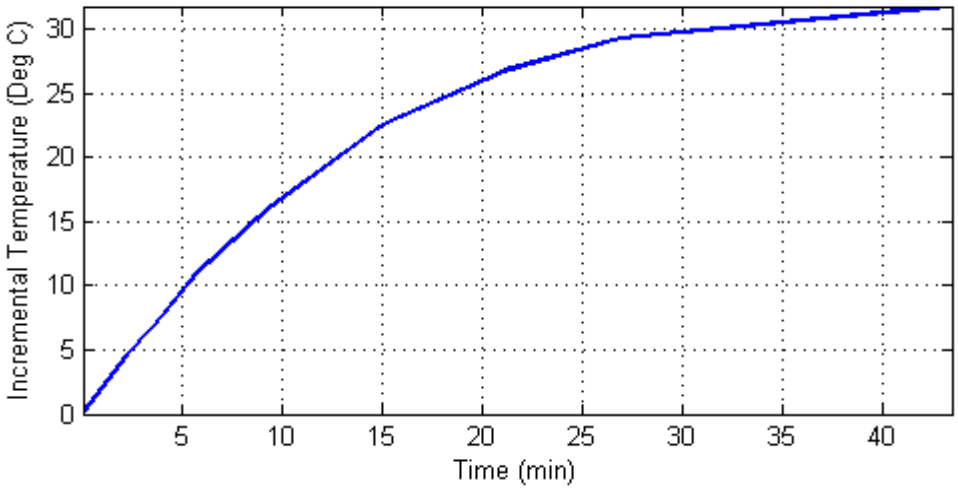


Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step

Metallic hot spot heating~~.~~

[10] Heating of bulk oil due to the hot spot temperature increase is not included in the asymptotic response because the time constant of bulk oil heating is at least an order of magnitude larger than the time constants of hot spot heating.

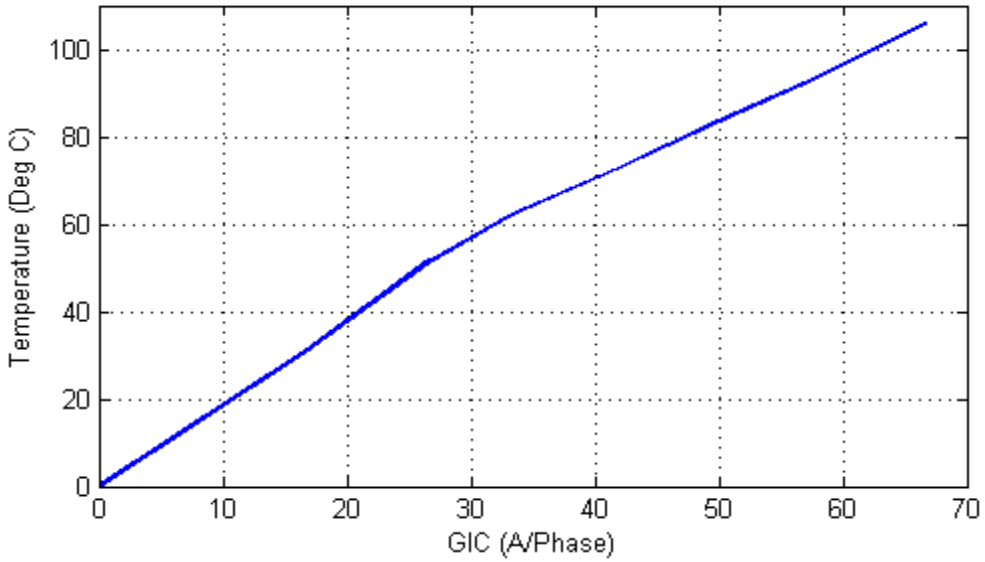


Figure 8: Asymptotic Thermal Step Response

Metallic hot spot heating~~.~~

The step response in **Figure 7** was obtained from the first GIC step of the tests carried out in [6]. The asymptotic thermal response in **Figure 8** was obtained from the final or near-final temperature values after each subsequent GIC step. **Figure 9** shows a comparison between measured temperatures and the calculated temperatures using the thermal response model used in the rest of this discussion.

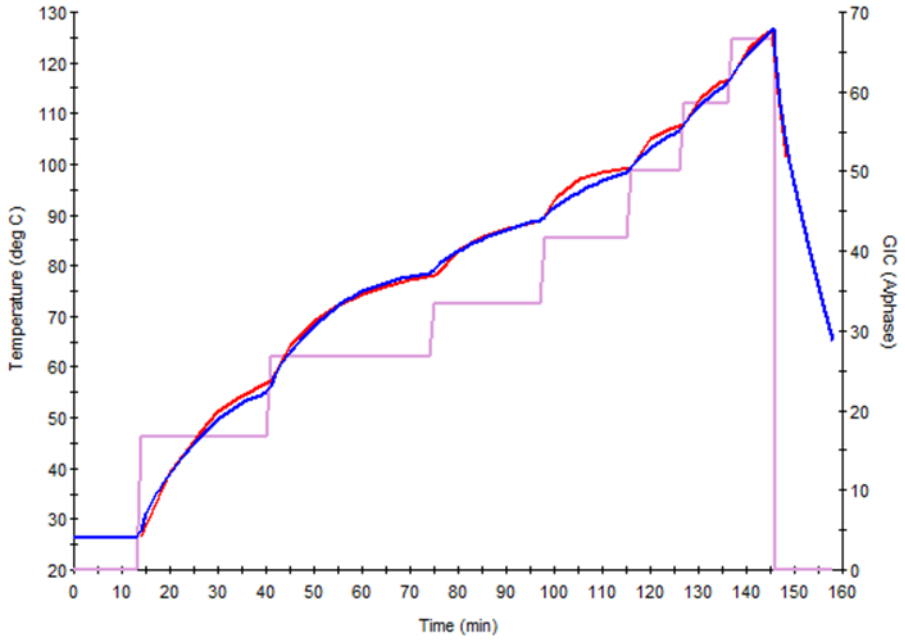


Figure 9: Comparison of measured temperatures (red ~~trace~~) and simulation results (blue ~~trace).~~).

Injected current is represented by ~~the~~ magenta ~~trace~~.

To obtain the thermal response of the transformer to a GIC ~~waveshape~~waveform such as the one in **Figure 6**, a thermal response model is required. To create a thermal response model, the measured or manufacturer-calculated transformer thermal step responses (winding and metallic part) for various GIC levels are required. The GIC(t) time series or ~~waveshape~~waveform is then applied to the thermal model to obtain the incremental temperature rise as a function of time $\theta(t)$ for the GIC(t) ~~waveshape~~waveform. The total temperature is calculated by adding the oil temperature, for example, at full load.

Figure 10 illustrates the calculated GIC(t) and the corresponding metallic hot spot temperature time series θ(t). **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

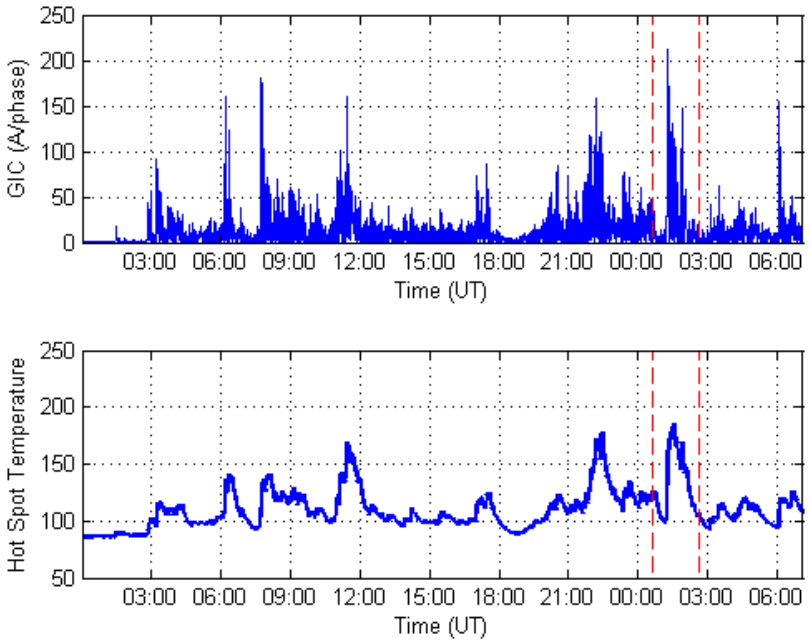


Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature θ(t) Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

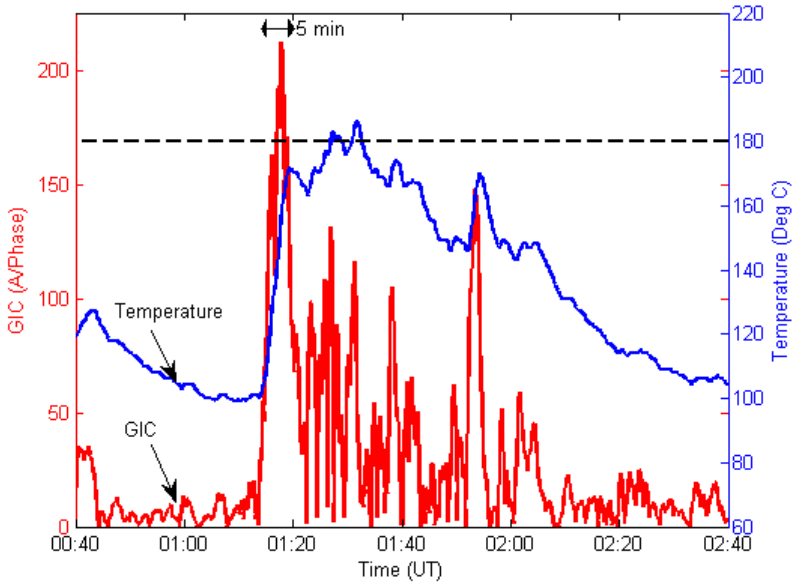


Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std C57.91-2011 emergency loading hot spot threshold of 200°C for metallic hot spot heating is not exceeded. Peak temperature is 186°C. The IEEE standard is silent as to whether the temperature can be higher than 200°C for less than 30 minutes. Manufacturers can provide guidance on individual transformer capability.

It is not unusual to use a lower temperature threshold of 180°C to account for calculation and data margins, as well as transformer age and condition. **Figure 11** shows that 180°C will be exceeded for 5 minutes.

At 75% loading, the initial temperature is 64.6°C rather than 85.3°C, and the hot spot temperature peak is 165°C, well below the 180°C threshold (see **Figure 12**).

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then the full load limits would be exceeded for approximately 22 minutes.

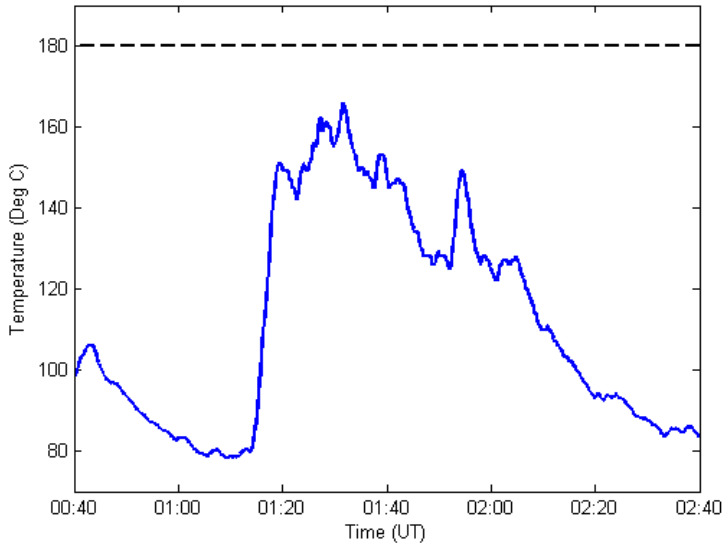


Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

Example 2: Using a Manufacturer's Capability Curves

The capability curves used in this example are shown in **Figure 13**. To maintain consistency with the previous example, these particular capability curves have been reconstructed from the thermal step response shown in **Figures 7** and **8**, and the simplified loading curve shown in **Figure 14** (calculated using formulas from IEEE Std C57.91~~).~~ 2011).

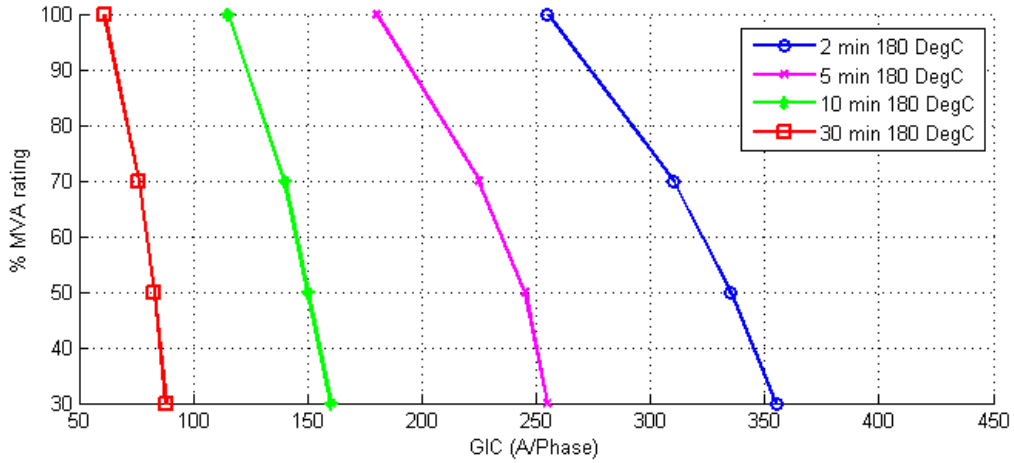


Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

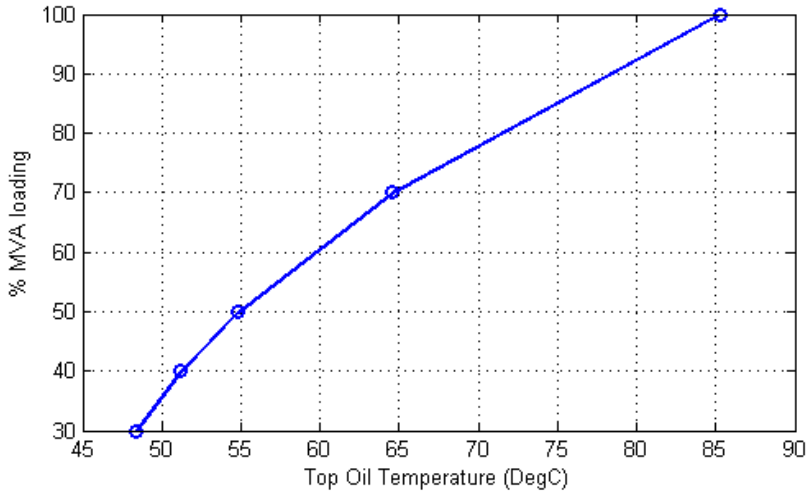


Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

The basic notion behind the use of capability curves is to compare the calculated GIC in a transformer with the limits at different GIC pulse widths. A narrow GIC pulse has a higher limit than a longer duration or wider one. If the calculated GIC and assumed pulse width falls below the appropriate pulse width curve, then the transformer is within its capability.

To use these curves, it is necessary to estimate an equivalent square pulse that matches the ~~waveshape~~waveform of GIC(t), generally at a GIC(t) peak. **Figure 15** shows a close-up of the GIC near its highest peak superimposed to a 255 Amperes per phase, 2 minute pulse at 100% loading from **Figure 13**. Since a narrow 2-minute pulse is not representative of GIC(t) in this case, a 5 minute pulse with an amplitude of 180 A/phase at 100% loading has been superimposed on **Figure 16**. It should be noted that a 255 A/phase, 2 minute pulse is equivalent to a 180 A/phase 5 minute pulse from the point of view of transformer capability. Deciding what GIC pulse is equivalent to the portion of GIC(t) under consideration is a matter of engineering judgment.

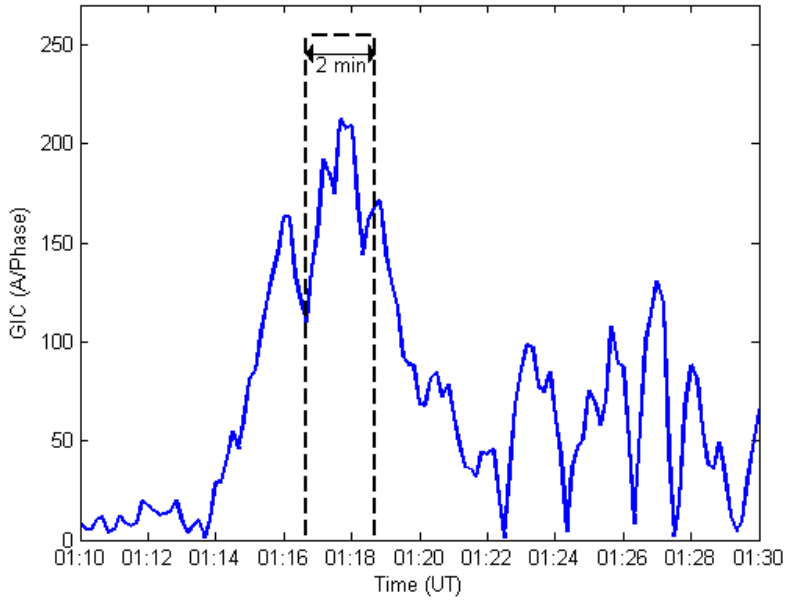


Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

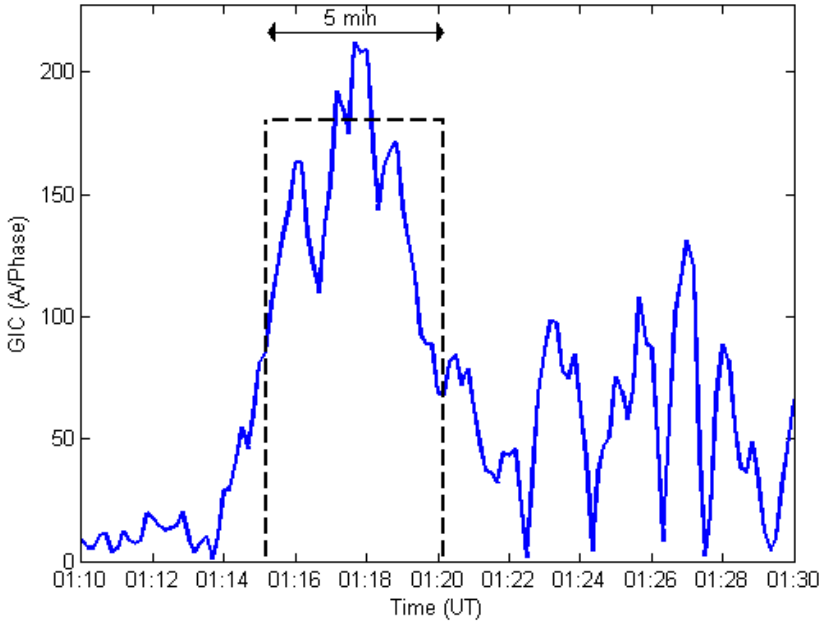


Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

When using a capability curve, it should be understood that the curve is derived assuming that there is no hot spot heating due to prior GIC at the time the GIC pulse occurs (only an initial temperature due to loading). Therefore, in addition to estimating the equivalent pulse that matches GIC(t), prior metallic hot spot heating must be accounted for. From these considerations, it is unclear whether the capability curves would be exceeded at full load with a 180°C threshold in this example.

At 70% loading, the two and five minute pulses from **Figure 13** would have amplitudes of 310 and 225 A/phase, respectively. The 5 minute pulse is illustrated in **Figure 17**. In this case, judgment is also required to assess if the GIC(t) is within the capability curve for 70% loading. In general, capability curves are easier to use when GIC(t) is substantially above, or clearly below the GIC thresholds for a given pulse duration.

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then a new set of capability curves would be required.

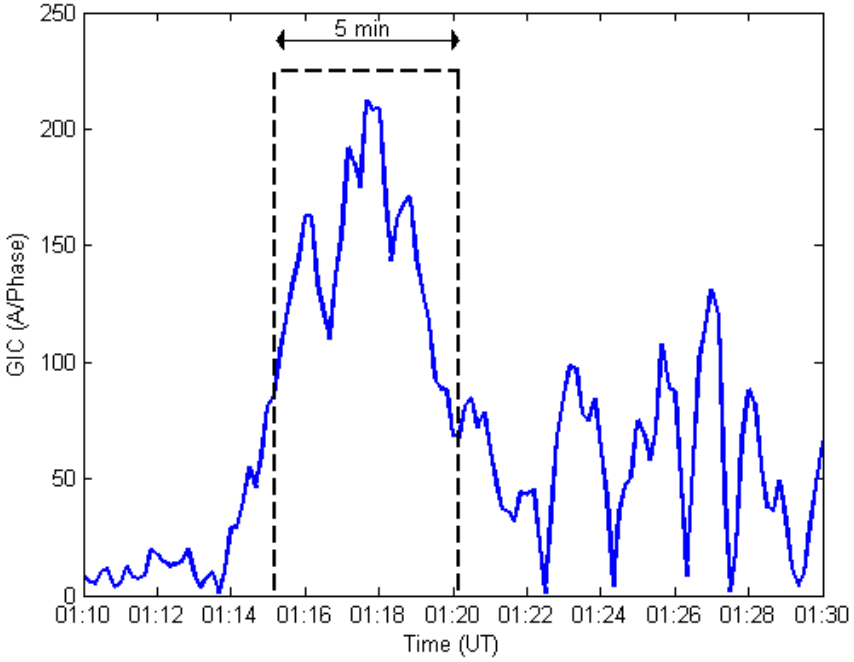


Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

References

[1] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

[2] Application Guide: Computing Geomagnetically-Induced Current in the Bulk-Power System, NERC. Available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

[3] "Screening Criterion for Transformer Thermal Impact Assessment". Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

[4] "IEEE Guide for Establishing Power Transformer Capability while under Geomagnetic Disturbances." IEEE Std C57.163-2015

~~[3]~~[5] Girgis, R.; Vedante, K. "Methodology for evaluating the impact of GIC and GIC capability of power transformer designs." IEEE PES 2013 General Meeting Proceedings. Vancouver, Canada.

~~[4]~~[6] Marti, L., Rezaei-Zare, A., Narang, A. "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents." IEEE Transactions on Power Delivery, vol.28, no.1. pp 320-327. January 2013.

~~[5]~~[7] Benchmark Geomagnetic Disturbance Event Description white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

[8] Supplemental Geomagnetic Disturbance Event Description white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

~~[6]~~[9] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

~~[7]~~[1] ~~"Screening Criterion for Transformer Thermal Impact Assessment". Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:~~

~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx~~

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

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	September 2017
10-day final ballot	January 2018
Board adoption	February 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.

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-~~1~~2**

3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.2. Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.3. Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   4.2.1. Generating unit(s).

   4.2.2. Generator step-up (i.e., GSU) transformer(s).

   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

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

[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-~~1~~2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

~~5.~~ **Background:**

6. After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. Standard Only Definition: None.

~~**7.1. Effective Date:** See Implementation Plan~~

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings.

C. Compliance

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

8. Compliance Monitoring Process

8.1. Compliance Enforcement Authority

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

8.2. Evidence Retention

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

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

8.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

8.4. Additional Compliance Information

None

~~Table of Compliance Elements~~

:

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-~~1~~2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

~~E. Interpretations~~

~~F.~~E. Associated Documents

NERC System Protection and Control Subcommittee, ~~July 2010, "~~"Considerations for Power Plant and Transmission System Protection Coordination~~."~~," technical reference document, Revision 2. (Date of Publication: July 2015)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, “IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers.” (Date of Publication: September 18, 2012)

IEEE C37.2-2008, “IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.” (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	

~~PRC-025-1~~2	April 19, 2017	SAR accepted by Standards Committee	Revision
2		Adopted by NERC Board of Trustees	
2		FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay ~~pickup~~ setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay ~~pickup~~ setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For ~~the application case~~applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads~~.),)~~, the ~~pickup~~ setting criteria shall be determined by vector summing the ~~pickup~~ setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative

assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for ~~Special Protection Systems~~Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of ~~fullload~~full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[3]
7. Protection systems that detect ~~transformer~~ overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 ~~beginning on the next page~~below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU

[3] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~. Elements may also supply generating plant loads).~~). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the ~~applied~~ application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text~~.~~, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and ~~pickup~~ setting criteria in the fourth and fifth column, respectively. The bus voltage column and ~~pickup~~ setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[4] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~),~~ or ~~(~~51V-R~~)~~ – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	~~The same application continues with a different relay type below~~			
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Asynchronous generating unit(s) (including inverter-based installations), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~),~~ or ~~(~~51V-R~~)~~ – voltage-restrained~~)~~	~~5~~5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 14~~ [5]	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] If the relay is installed on the high-side of the GSU transformer use Option 14.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 15~~ [6]	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[6] If the relay is installed on the high-side of the GSU transformer use Option 15.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 16~~ [7]	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[7] If the relay is installed on the high-side of the GSU transformer use Option 16.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 17~~[8]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 18~~[9]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	~~The same application continues on the next page with a different relay type~~			

[8] If the relay is installed on the high-side of the GSU transformer use Option 17.
[9] If the relay is installed on the high-side of the GSU transformer use Option 18.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 19~~[10]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts ~~below~~on the next page				
Unit auxiliary transformer(s) (UAT)	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
~~A different application starts on the next page~~				

[10] If the relay is installed on the high-side of the GSU transformer use Option 19.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. (Elements may also supply generating plant loads.) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system —installed on the high-side of the GSU transformer ~~If the relay is installed~~ and on the ~~generator-side~~remote end of ~~the GSU transformer use Option 7~~line[11]	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		~~OR~~		
		~~14b~~	~~Simulated line voltage coincident with the highest Reactive Power output achieved during field forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field forcing~~	~~The impedance element shall be set less than the calculated impedance derived from 115% of:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and~~ ~~(2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field forcing as determined by simulation~~
	~~The same application continues on the next page with a different relay type~~			

[11] If the relay is installed on the generator-side of the GSU transformer use Option 7.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. — connected to synchronous generators~~	~~Phase overcurrent supervisory element (50) — associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) — installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 8~~	~~15a~~	~~0.85 per unit of the line nominal voltage~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output — 100% of the aggregate generation gross MW reported to the Transmission Planner, and~~ ~~(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor~~
		OR		
		~~15b~~14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The ~~overcurrent~~impedance element shall be set ~~greater~~less than ~~115% of~~ the calculated ~~current~~impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit	Phase ~~directional~~instantaneous overcurrent supervisory element (~~67~~e.g., 50) – associated with current-based, communication-	~~16a~~15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
or generating plant~~.~~ (Elements may also supply generating plant ~~load.~~ loads) – connected to synchronous generators	assisted schemes where the scheme is capable of tripping for loss of communications ~~directional toward the Transmission system~~ installed on the high-side of the GSU transformer and remote end of the line and/or phase ~~directional~~ time overcurrent relay (~~67) – directional toward the Transmission system~~e.g., 51) – installed on the high-side of the GSU transformer ~~If the relay is installed on the generator-side of the GSU transformer use Option 9~~and remote end of the line[12]	15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer use Option 8.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant load.) – connected to synchronous generators	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line[13]	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[13] If the relay is installed on the generator-side of the GSU transformer use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system– installed on the high-side of the GSU transformer ~~If the relay is installed~~ and on the ~~generator-side~~remote end of ~~the GSU transformer use Option 10~~line[14]	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[14] If the relay is installed on the generator-side of the GSU transformer use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase time overcurrent relay (e.g., 51) – installed on the high-side of the GSU transformer ~~If the relay is installed on the generator side of~~ and on the ~~GSU transformer use Option 11~~remote end of the line[15]	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
	The same application continues on the next page with a different relay type			

[15] If the relay is installed on the generator-side of the GSU transformer use Option 11.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase directional time overcurrent relay (e.g., 67) – installed on the high-side of the GSU transformer ~~If the relay is installed on the generator side of~~ and on the ~~GSU transformer use Option 12~~remote end of the line[16]	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

[16] If the relay is installed on the generator-side of the GSU transformer use Option 12.

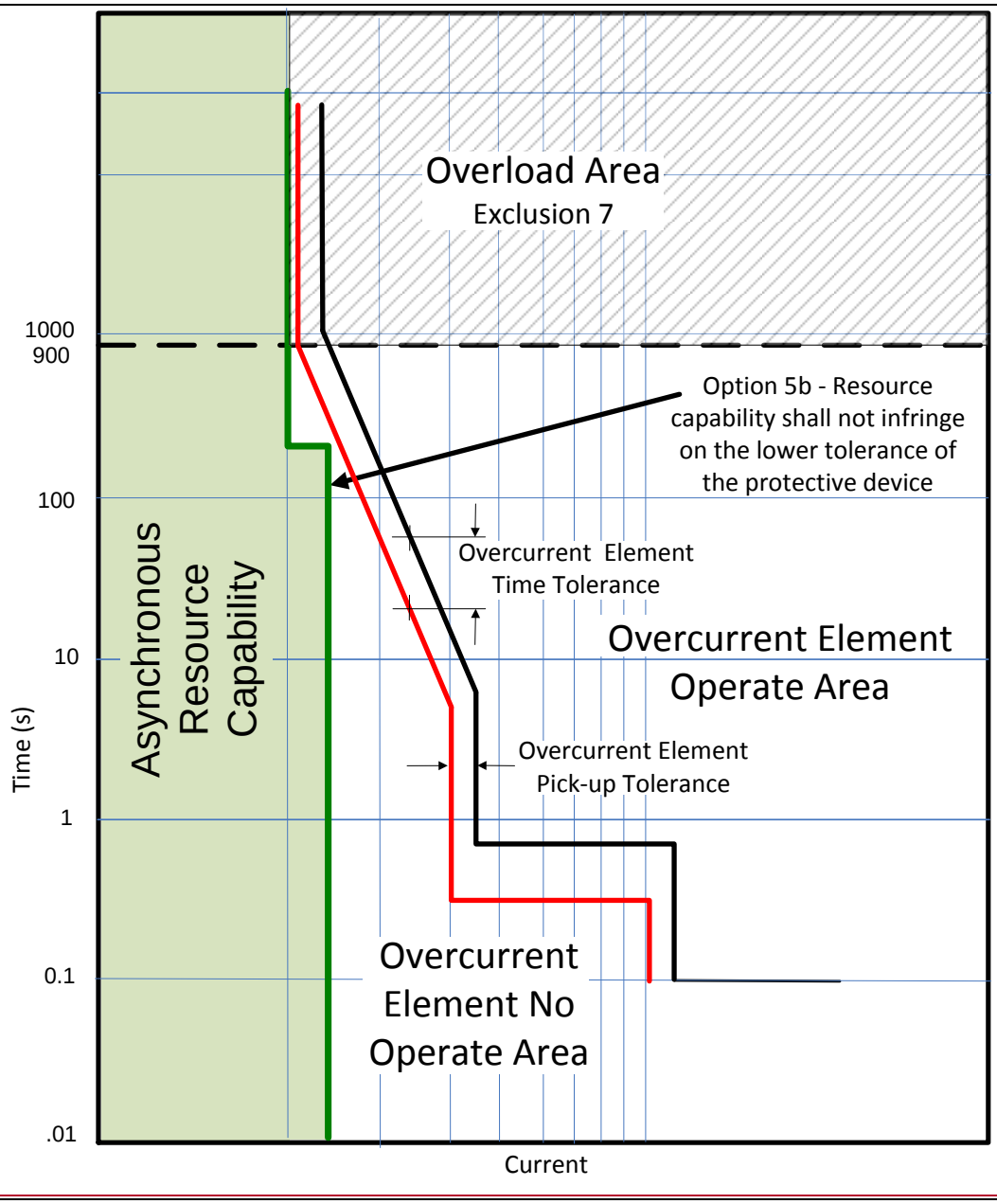


Figure A. This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-~~1~~2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July ~~2010~~2015.[17]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard

[17] ~~http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf~~
http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf

is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.
For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system.

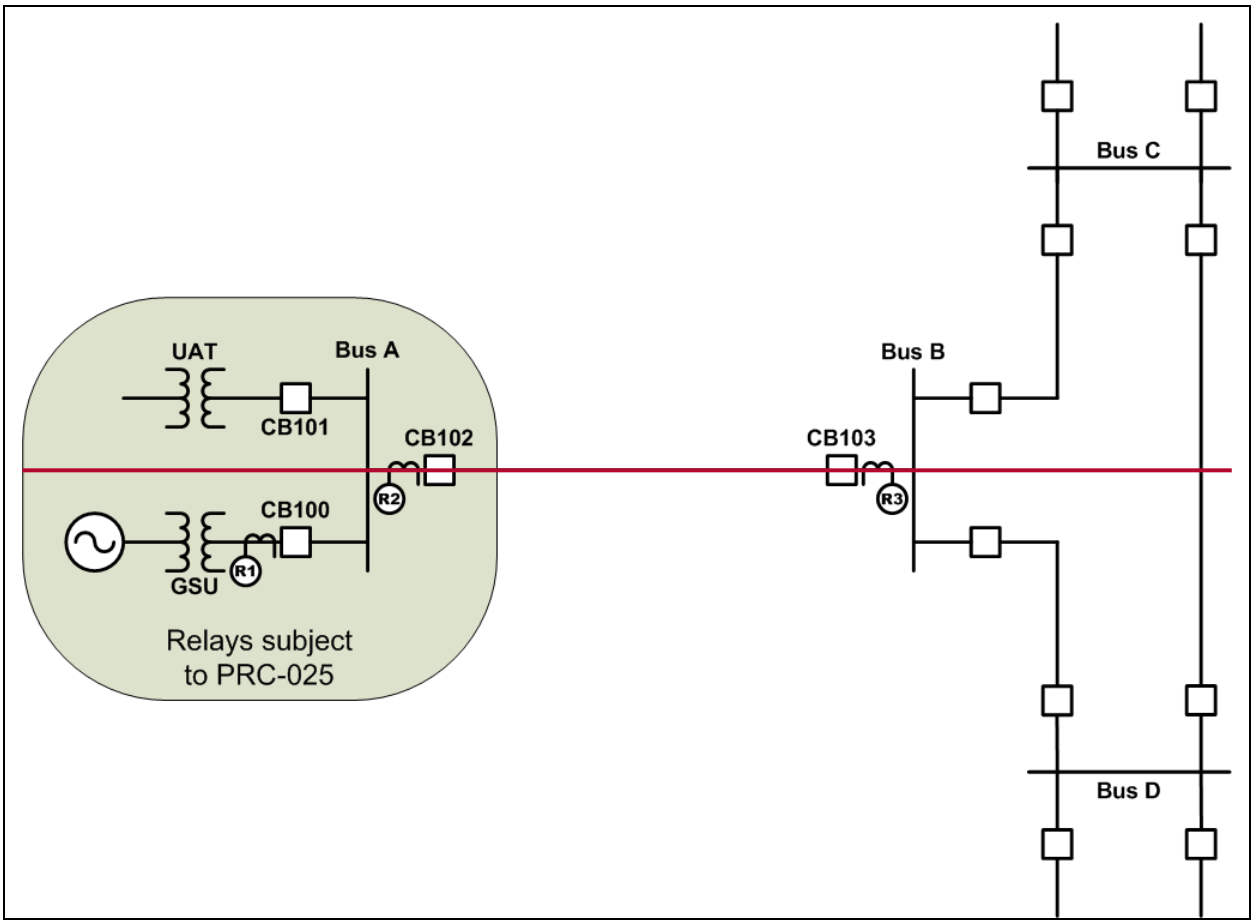
Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

~~In this particular case, the applicable responsible entity's directional relay R3 located on breaker CB103 at Bus B looking toward Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not affected by increased generator output in response to system disturbances described in this standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.~~


UAT
Bus A
CB101
CB102
CB100
R2
R1
GSU
Relays subject
to PRC-025
Bus B
CB103
R3
Bus C
Bus D

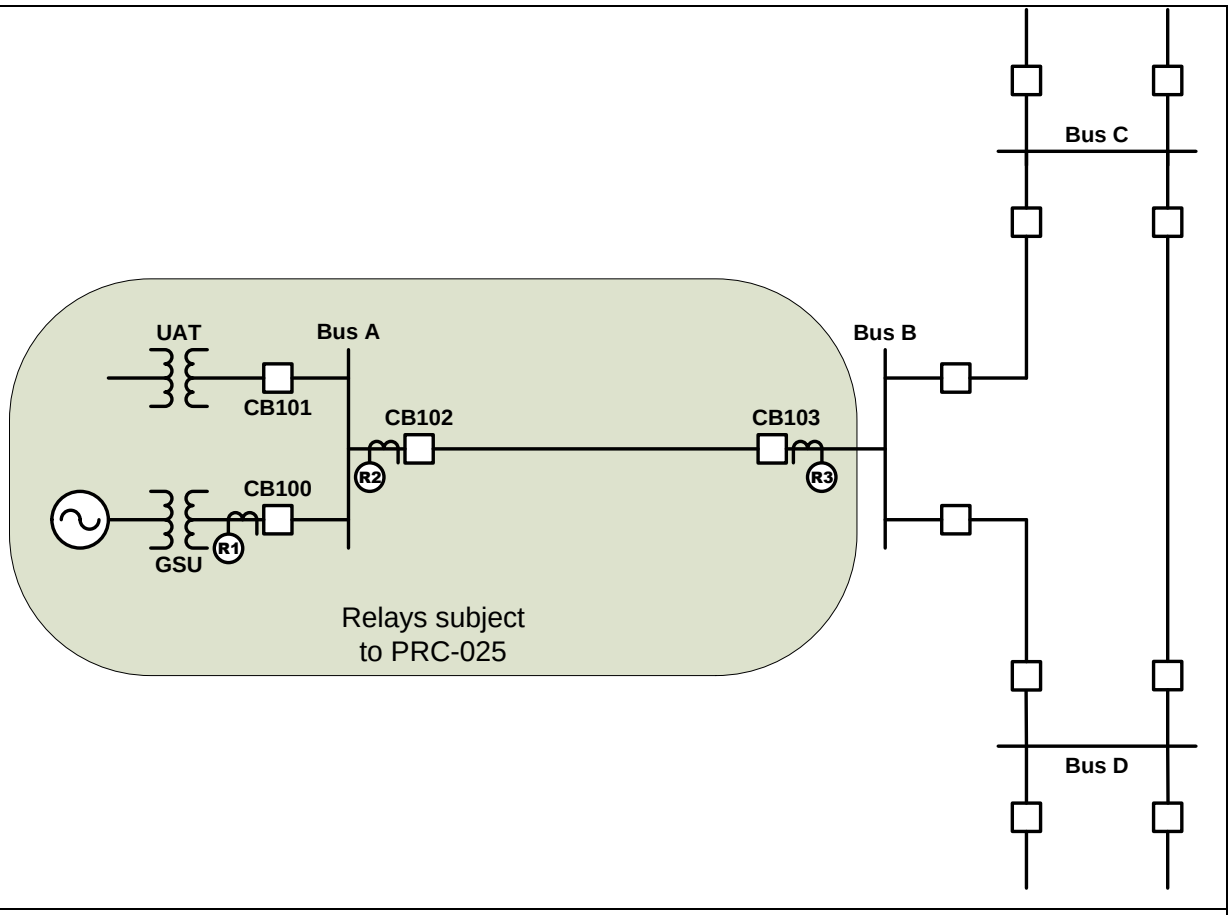


Figure 1. Generation exported through a single radial line.

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

~~In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.~~

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

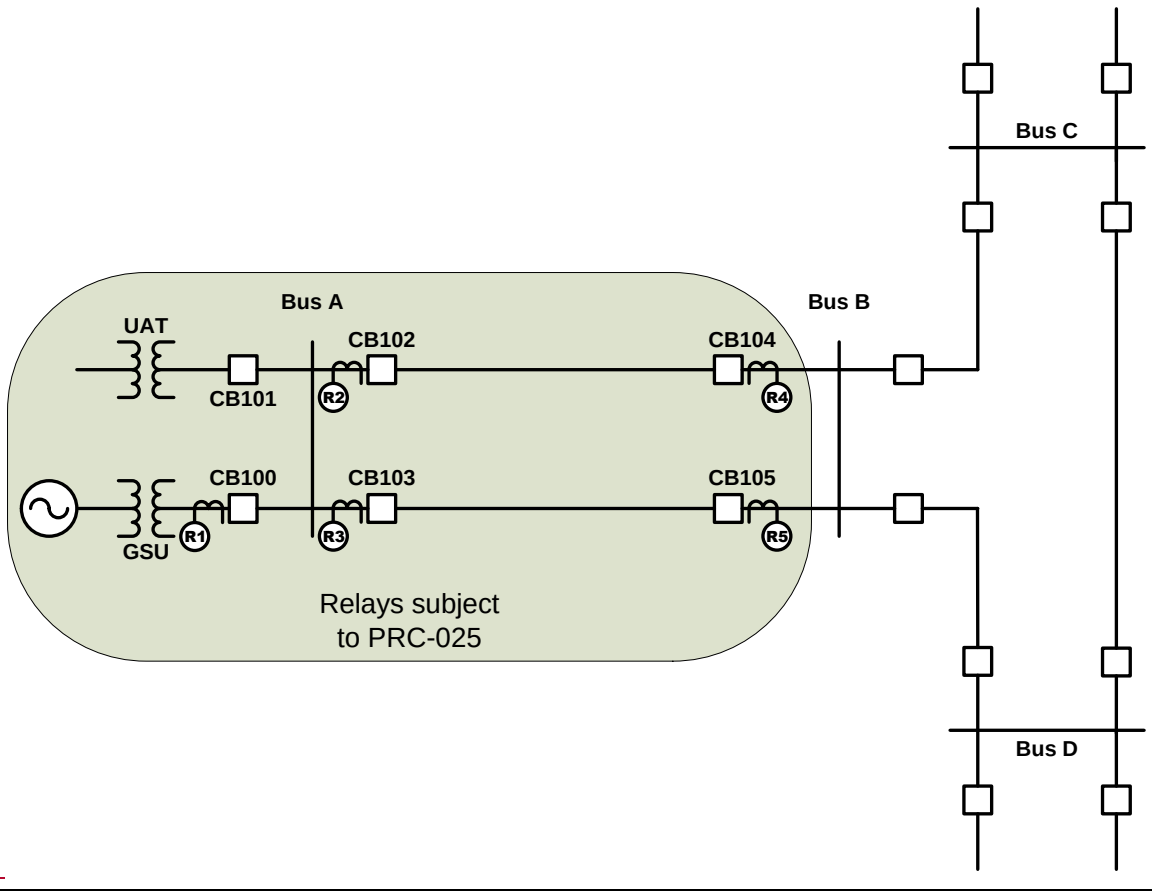


Figure 2. Generation exported through multiple radial lines.

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

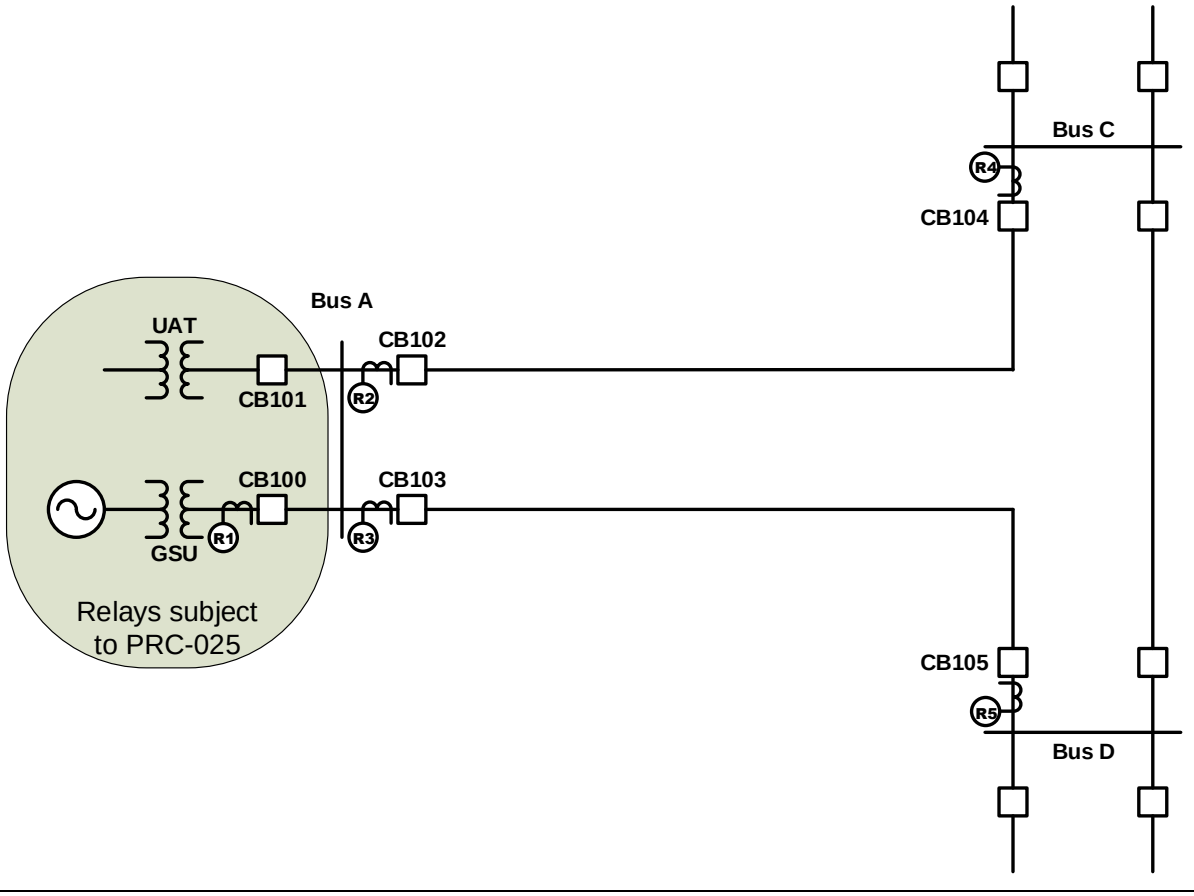


Figure 3. Generation exported through a network.

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of

the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of ~~Transmission system~~the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had ~~not~~ other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "~~Pickup~~ Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line

during a system disturbance; therefore, all output load-responsive protective ~~elements~~relays associated with the facility are included in PRC-~~-~~025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-~~1~~2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-~~1~~2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 5) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators~~, however, do not have excitation systems and~~ will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before ~~a crowbar function~~limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage ~~on~~at the

remote end of the line or at the high-side of the GSU transformer~~.~~ (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor ~~on~~at the ~~Transmission system to lower~~remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage to be used to calculate relay ~~pickup~~ setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, ~~contributing~~which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to*

clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the ~~Table 1~~ setting criteria established within the Table 1 options ~~differ~~differs from ~~section 3.9.2 of~~ the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. ~~See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.~~

~~**Phase Time Overcurrent Relay – Voltage Controlled (51V-C)**~~

~~Phase time overcurrent voltage-controlled relays (51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See section 3.10 of the~~See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional ~~time~~ overcurrent relays is similar. Note that the ~~Table 1setting~~setting criteria established within the Table 1 options ~~differ~~differs from ~~section 3.9.2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-~~1~~2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

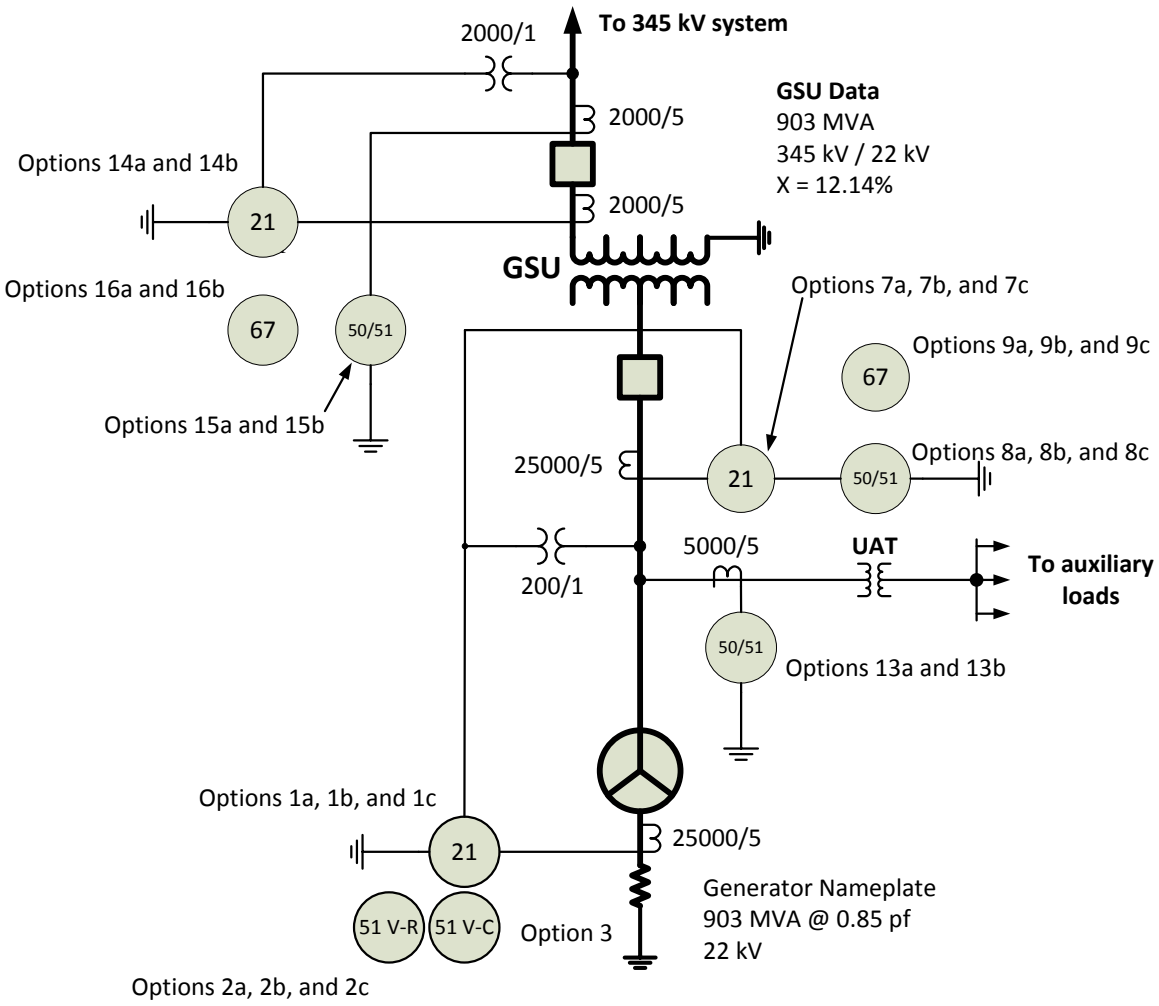


Figure 4. Relay Connection for corresponding synchronous options.

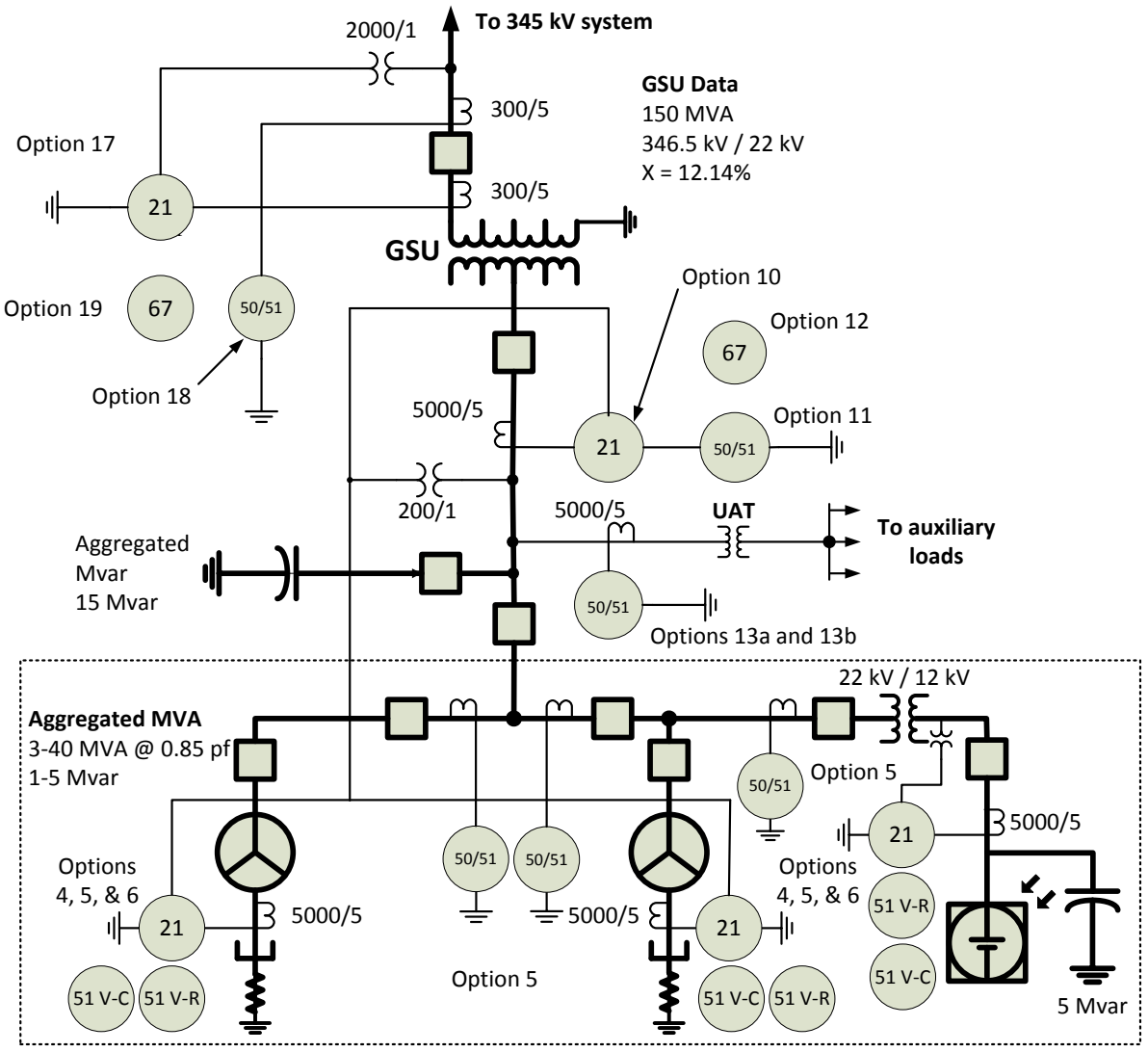


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~

calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts for~~as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~ in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element ~~is~~shall be set less than the calculated impedance derived from ~~115percent~~115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage~~-~~ Restrained ~~(51V-R~~) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase ~~time~~ overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which ~~change their~~changes its sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer

is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts~~as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element ~~is~~shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators;~~

~~the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option 4, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage~~-~~ Restrained ~~(51V-R) (Option 5)~~ (Options 5a and 5b))

Table 1, Option ~~5~~5a is provided for assessing loadability for asynchronous generators applying phase ~~time~~ overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which ~~change their~~changes its sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option ~~5~~5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer

~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option ~~5~~5a, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The overcurrent element shall be set to not infringe upon the resource capability with worst case documented tolerances applied to the setting. Figure A illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability ~~for GSU transformers applying~~of phase distance relays that are directional toward the Transmission system ~~on synchronous generators that are~~and connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~overcurrent~~impedance element ~~overall~~than Options 7a or 7b.

For Options 7a and 7b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate

generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 7c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. ~~Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

~~Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for GSU transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 15.~~

~~Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.~~

~~Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.~~

~~Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.~~

~~For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW~~

~~capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.~~

~~For Option 8c, the overcurrent element~~ ~~is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.~~

~~Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)~~

~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers.~~ ~~Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document.~~ Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability ~~for GSU transformers applying~~of phase directional ~~time~~ overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~impedance~~overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more

~~involved, more~~in-depth and precise method for setting ~~of~~ the overcurrent element ~~overall~~than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 9c, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element ~~is~~shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. ~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability ~~for GSU transformers applying~~of phase ~~time~~ overcurrent relays ~~on asynchronous generators~~ that are connected to the generator-side of the GSU transformer~~. Where~~ of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.~~

~~Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option 11, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined

by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

~~Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)~~

~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers.~~ ~~Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

~~Table 1, Option 12 is provided for assessing loadability for GSU transformers applying phase directional time overcurrent relays directional toward the Transmission System on asynchronous generators that are connected to the generator-side of the GSU transformer of an asynchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 19.~~
~~Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer.~~ ~~The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.~~
~~Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage.~~ ~~Asynchronous generators do not produce as much Reactive Power as synchronous generators;~~ ~~the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~
~~For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices.~~ ~~This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.~~

Unit Auxiliary Transformers Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase ~~time~~ overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase ~~time~~ overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard.

Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase ~~time~~ overcurrent relaying applied ~~to~~at the low-side of the UAT are not addressed in this standard. These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.

Refer to the Figures 6 and 7 below for example configurations:

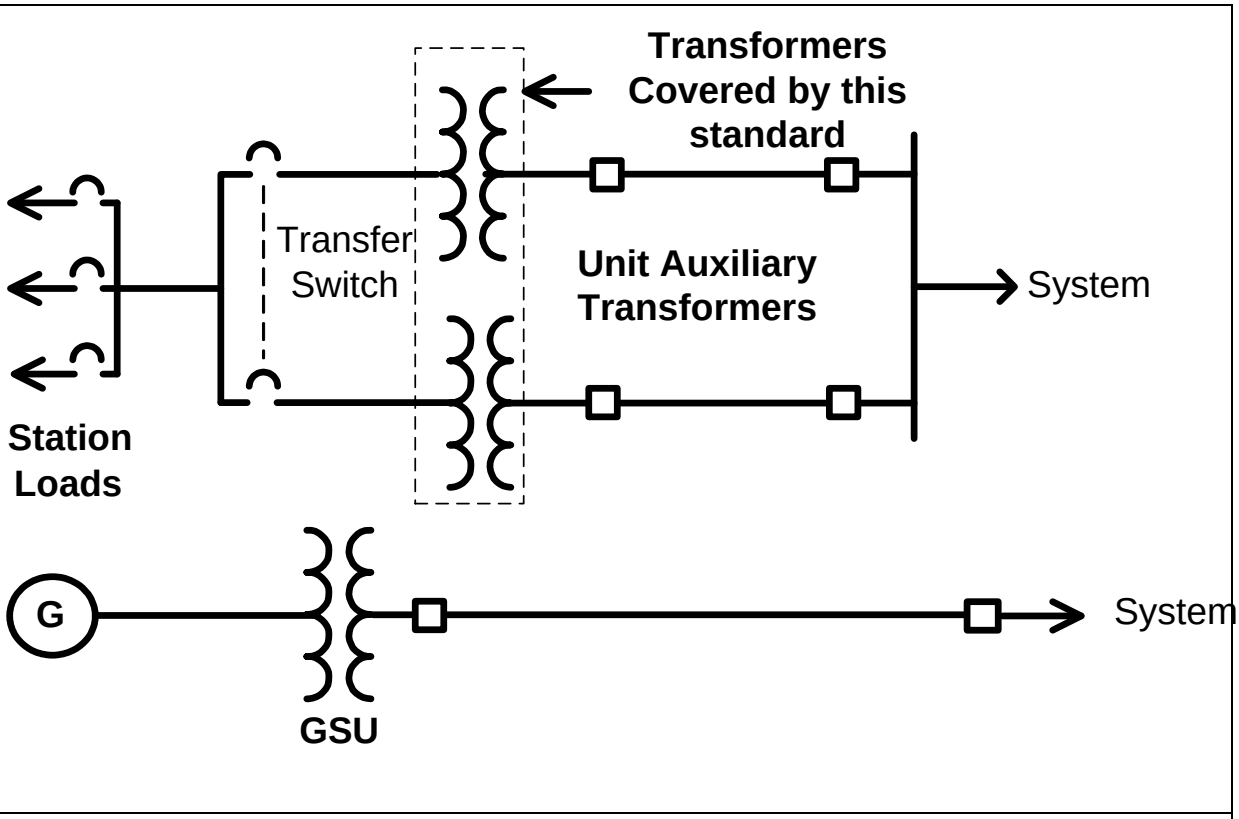


Figure-6 – Auxiliary Power System (independent from generator).

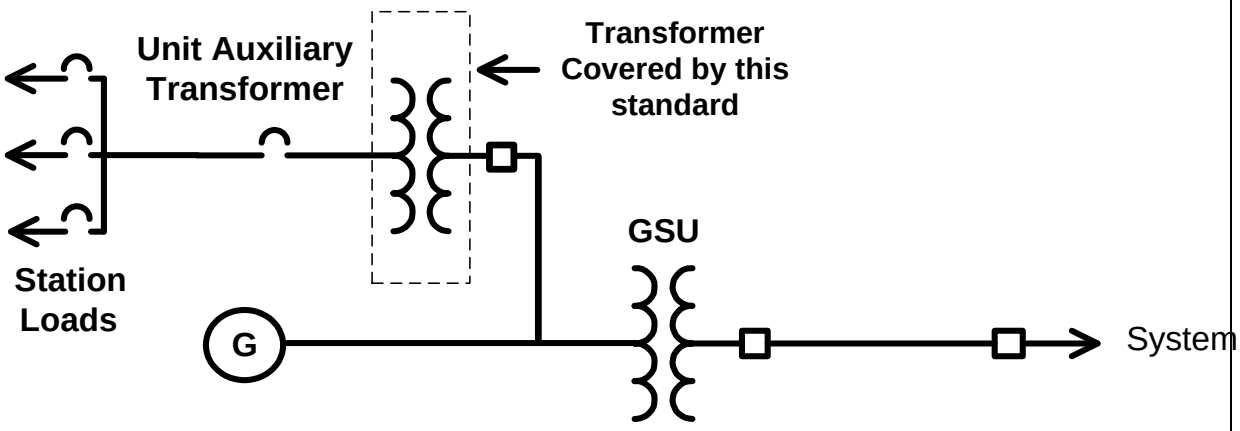


Figure-7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase ~~time~~ overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting ~~pickup~~ compared to Option 13a and the entity's relay setting philosophy. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response

of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum ~~pickup~~setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy

directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase

instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional ~~time~~ overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high side terminals of the GSU transformer prior to field forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the impedance from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 17, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase ~~time~~ overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals~~location of the ~~GSU transformer~~relay to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 18, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 19, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio_hv} = \frac{2000}{5}$

Example Calculations.	
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$
Reactive Power output of static reactive device generation:	$MVAR_{gen_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch_ratio_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio_remote_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7° \, \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7° \, \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7° \, \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7° \, \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{8.035\angle 58.7° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 6.9873\angle 58.7° \, \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873 \, \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873 \, \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0° \, \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $$P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{~~7.74\ \Omega~~}{~~\cos(85.0° - 58.7°)~~} \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633 \angle 85.0° \ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

In this simulation the following values are derived:

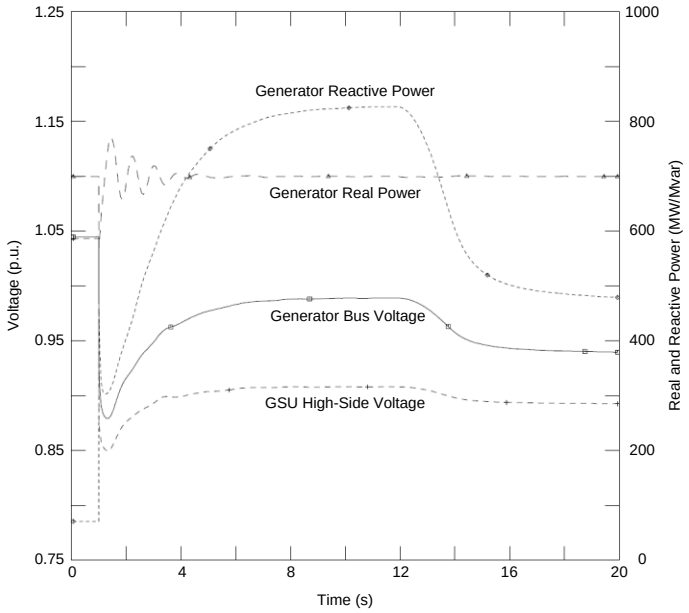
$$Q = 827.4\ Mvar$$

$$~~V_{bus}~~V_{bus_simulated} = 0.989 \times V_{gen_nom} = 21.76\ k\text{V}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch_reported} = 700.0\ MW$$

Example Calculations: Options 1c and 7c



Apparent power (S):

Eq. (24) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{\cancel{V_{bus}^2}}{\cancel{S^*}} \frac{V_{bus_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

Example Calculations: Options 1c and 7c

$$Z_{sec} = 0.437\angle 49.8° \, \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8° \, \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{10.92\angle 49.8° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 9.50\angle 49.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{\text{~~9.50 Ω~~}}{\text{~~cos(85.0° − 49.8°)~~}} \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < \ 11.63\angle 85.0° \, \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (29) $$P = \ GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \ \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Option 2a

Reactive Power output (Q):

Eq. (30) $Q = 150\% \times P$

$Q = 1.50 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$

$V_{gen} = 20.81\ kV$

Apparent power (S):

Eq. (32) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4 \angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (33) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$

$I_{pri} = 37383\ A$

Secondary current (I_{sec}):

Eq. (34) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$

Example Calculations: Option 2a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.477\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Example Calculations: Option 2b

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Option 2b

Apparent power (S):

Eq. (46) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4 \angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (47) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$

$I_{pri} = 35553\ A$

Secondary current (I_{sec}):

Eq. (48) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$

$I_{sec} = 7.111\ A$

To satisfy the 115% margin in Option 2b:

Eq. (49) $I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$

$I_{\mathrm{sec}\,limit} > 7.111\ A \times 1.15$

$I_{\mathrm{sec}\,limit} > 8.178\ A$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.

~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.~~

In this simulation the following values are derived:

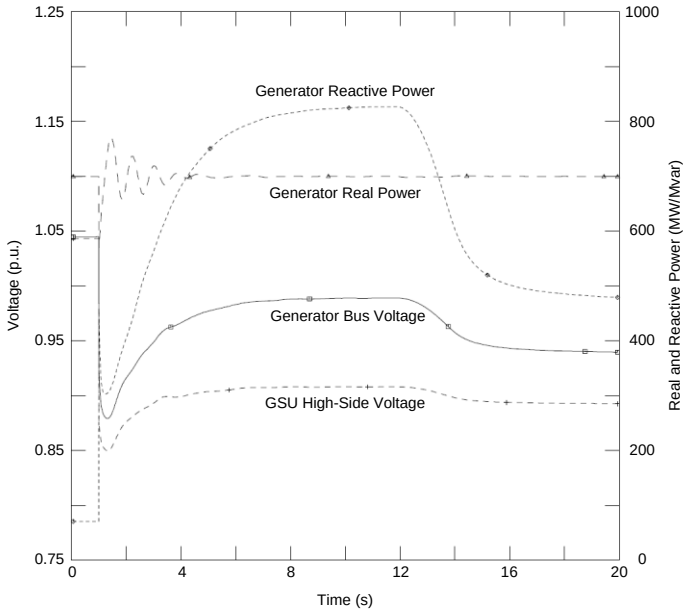
$$Q = 827.4\ Mvar$$

$$~~V_{bus}~~V_{bus_simulated} = 0.989 \times V_{gen_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch_reported} = 700.0\ MW$$

Example Calculations: Option 2c



Apparent power (S):

Eq. (50) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j827.4\ Mvar$

$S = 1083.8 \angle 49.8°\ MVA$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \frac{~~S~~}{~~\sqrt{3} \times V_{bus}~~} \frac{S}{\sqrt{3} \times V_{bus_simulated}}$

$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$

$I_{pri} = 28790\ A$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$

Example Calculations: Option 2c

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 5.758\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C)~~ voltage controlled~~ relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21)— directional toward the Transmission system.

Example Calculations: Option 4

Real Power output (P):

Eq. (56) $$P = GEN_{Asych_nameplate} \times pf$$

$$P = 40\ MVA \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0 \angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0 \angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99 \angle 31.8°\ \Omega$$

Example Calculations: Option 4

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99 \angle 31.8° \, \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99 \angle 31.8° \, \Omega \times 5$$

$$Z_{sec} = 59.95 \angle 31.8° \, \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\text{sec}\,limit} = \frac{59.95 \angle 31.8° \, \Omega}{1.30}$$

$$Z_{\text{sec}\,limit} = 46.12 \angle 31.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~,85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12 \, \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12 \, \Omega}{0.599}$$

$$Z_{max} < 77.0 \angle 85.0° \, \Omega$$

Example Calculations: Option ~~5~~5a

This represents the calculation for three asynchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~– voltage-restrained~~ relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option ~~5~~5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Option ~~5~~5a

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option ~~5~~5a:

Eq. (70) $$I_{\text{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\text{sec}\,limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\text{sec}\,limit} > 4.52\angle -39.2°\ A$$

Example Calculations: ~~Options 7a and 10~~Option 5b

~~This~~Similarly to Option 5a, this example represents the calculation for ~~a mixture of~~three asynchronous ~~(i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations)~~generators applying a phase ~~distance~~overcurrent (e.g., 50, 51, or 51V-R) relay ~~(21) – directional toward the Transmission system.~~. In this application it was assumed that 20 Mvar of total static compensation was added.

~~**Synchronous Generation (Option 7a)**~~

Real Power output (~~P_{sync}~~):P):

Eq. (71) ~~$P_{Synch} = GEN_{Synch_nameplate} \times pf$~~$P = 3 \times GEN_{Asynch_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Example Calculations: ~~Options 7a and 10~~Option 5b

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

Example Calculations: ~~Options 7a and 10~~Option 5b

$$I_{sec} = 3.473\angle -39.2° \; A$$

To satisfy Option 5b, the overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch_nameplate} \times pf$$

$$P_{Synch} = 903 \; MVA \times 0.85$$

$$P_{Synch} = 767.6 \; MW$$

Reactive Power output (Q_{synch}):

Eq. (~~72~~78) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6 \; MW$$

$$Q_{Synch} = 1151.3 \; MW$$

Apparent power (S_{Synch}):

Eq. (~~73~~79) $$S_{Synch} = P_{Synch_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0 \; MW + j1151.3 \; Mvar$$

Example Calculations: Options 7a and 10

Asynchronous Generation (Option 10)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~74~~80) $P_{Asynch} = 3 \times GEN_{Asynch_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (~~75~~81) $Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (~~76~~82) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (~~77~~83) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (~~78~~84) $S = 115\% \times \left(P_{Synch_reported} + jQ_{Synch}\right) + 130\% \times (P_{Asynch} + jQ_{Asynch})$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

Example Calculations: Options 7a and 10

$$S = 1711.8 \angle 56.8° \, MVA$$

Primary impedance (Z_{pri}):

Eq. (~~79~~85) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81 \, kV)^2}{1711.8 \angle -56.8° \, MVA}$$

$$Z_{pri} = 0.2527 \angle 56.8° \, \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~80~~86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527 \angle 56.8° \, \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527 \angle 56.8° \, \Omega \times 25$$

$$Z_{sec} = 6.32 \angle 56.8° \, \Omega$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~85~~84 to satisfy the margin requirements in Options 7a and 10~~:~~.

Eq. (~~81~~87) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\text{sec}\,limit} = \frac{6.32 \angle 56.8° \, \Omega}{1.00}$$

$$Z_{\text{sec}\,limit} = 6.32 \angle 56.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (~~82~~88) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

Example Calculations: Options 7a and 10

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} < 7.17 \angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (~~83~~89) $P = GEN_{Synch_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~84~~90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (~~85~~91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Example Calculations: Options 8a and 9a

Apparent power (S):

Eq. (~~86~~92) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4 \angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (~~87~~93) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$

$I_{pri} = 37383\ A$

Secondary current (I_{sec}):

Eq. (~~88~~94) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$

$I_{sec} = 7.477\ A$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (~~89~~95) $I_{\text{sec}\,limit} > I_{sec} \times 115\%$

$I_{\text{sec}\,limit} > 7.477\ A \times 1.15$

$I_{\text{sec}\,limit} > 8.598\ A$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more ~~complex~~precise calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch_nameplate}$ value to represent an “aggregate” value to illustrate the option:

Example Calculations: Options 8b and 9b

Real Power output (P):

Eq. (~~90~~96) $P = GEN_{Synch_nameplate} \times pf$

$P = 903\ MVA \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

Eq. (~~91~~97) $Q = 150\% \times P$

$Q = 1.50 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU Transformer MVA_{base}).

Real Power output (P):

Eq. (~~92~~98) $P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$

$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$

$P_{pu} = 0.91\ p.u.$

Reactive Power output (Q):

Eq. (~~93~~99) $Q_{pu} = \frac{Q}{MVA_{base}}$

$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$

$Q_{pu} = 1.5\ p.u.$

Transformer impedance:

Eq. (~~94~~100) $X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$

Example Calculations: Options 8b and 9b

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (~~95~~101)
$$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \lceil V_{high-side} \rceil\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (~~97~~103)
$$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \lceil V_{high-side} \rceil\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Example Calculations: Options 8b and 9b

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (~~99~~105)
$$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (~~100~~106)
$$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4 \angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (~~101~~107)
$$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Example Calculations: Options 8b and 9b

Secondary current (I_{sec}):

Eq. (~~102~~108)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (~~103~~109)
$$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.111\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

~~Real Power output (P_{Synch}):~~

Real Power output (P_{Synch}):

Eq. (~~104~~110)
$$P_{Synch} = GEN_{Synch_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 8a, 9a, 11, and 12

Reactive Power output (Q_{Synch}):

Eq. (~~105~~111) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (~~106~~112) $$S_{Synch} = P_{Synch_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4 \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (~~107~~113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (~~108~~114) $$I_{pri-sync} = \frac{115\% \times S^{*}_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061 \angle -58.7°\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

Asynchronous Generation (Options 11 and 12)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~109~~115)
$$P_{Asynch} = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (~~110~~116)
$$Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (~~111~~117)
$$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{Asynch}):

Eq. (~~112~~118)
$$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{Asynch} = 171.1 \angle 39.2°\ MVA$$

Example Calculations: Options 8a, 9a, 11, and 12

Primary current ($I_{pri\text{-}async}$):

Eq. (~~113~~119)
$$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1 \angle -39.2° \, MVA}{1.73 \times 20.81 \, kV}$$

$$I_{pri-async} = 4755 \angle -39.2° \, A$$

Secondary current (I_{sec}):

Eq. (~~114~~120)
$$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061 \angle -58.7° \, A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \, A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \, A$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation ~~94~~114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~98:~~118.

Eq. (~~115~~121)
$$I_{\text{sec}\,limit} > I_{sec} \times 100\%$$

$$I_{\text{sec}\,limit} > 9.514 \angle -56.8° \, A \times 1.00$$

$$I_{\text{sec}\,limit} > 9.514 \angle -56.8° \, A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase ~~time~~ overcurrent relay~~.~~ (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter

Example Calculations: Options 8c and 9c

reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

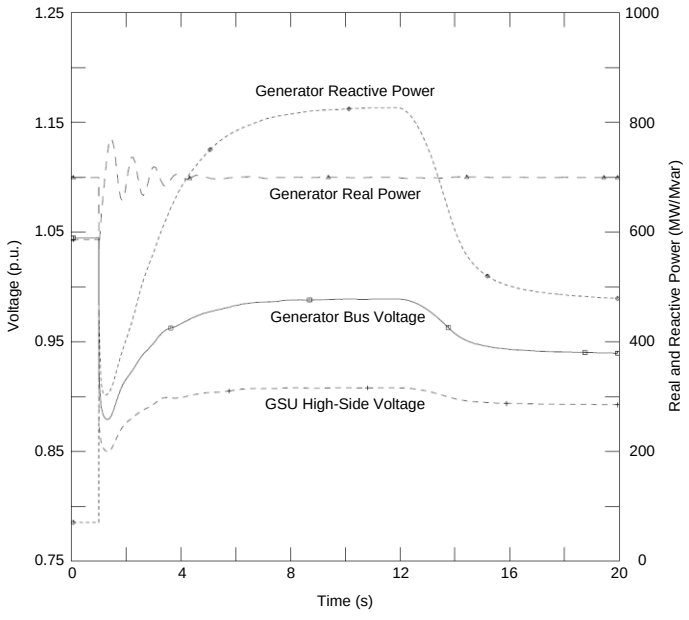
In this simulation the following values are derived:~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low side of the GSU transformer during field forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.~~

$$Q = 827.4\ Mvar$$

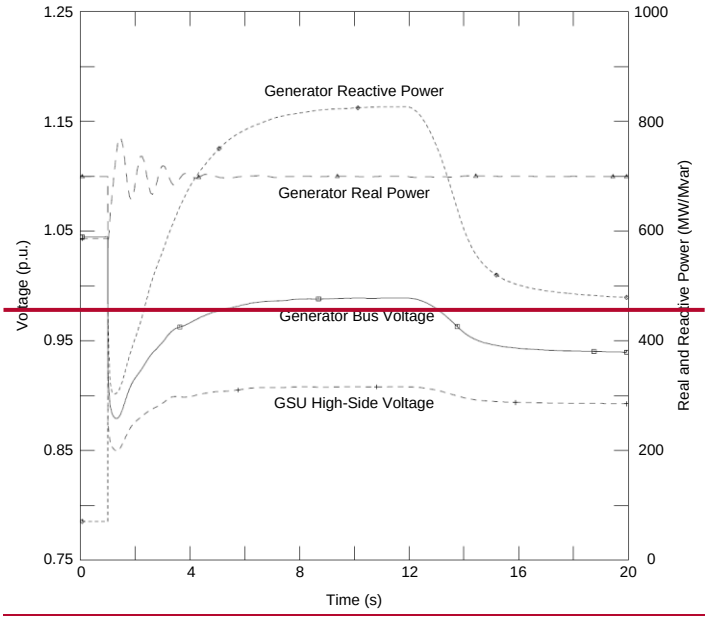
$$~~V_{bus}~~V_{bus_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Example Calculations: Options 8c and 9c



Apparent power (S):

Eq. (~~116~~122) $S = P_{Synch_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (~~117~~123) $I_{pri} = \frac{~~S~~}{~~\sqrt{3} \times V_{bus}~~} \frac{S}{\sqrt{3} \times V_{bus_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (~~118~~124) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8c and 9c

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (~~119~~125) $I_{\text{sec } limit} > I_{sec} \times 115\%$

$$I_{\text{sec } limit} > 5.758\ A \times 1.15$$

$$I_{\text{sec } limit} > 6.622\ A$$

Example Calculations: Option10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21)— directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~120~~126) $P = 3 \times GEN_{Asych_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~121~~127) $Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (~~122~~128) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

Example Calculations: Option10

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (~~123~~129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~124~~130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~125~~131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (~~126~~132) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\text{sec}\,limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

Example Calculations: Option10

$$Z_{\sec limit} = 14.02\angle 39.2° \ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (~~127~~133)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0° \ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase ~~time~~ overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional ~~time~~ overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~128~~134)
$$P = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~129~~135)
$$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

Example Calculations: Options 11 and 12

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (~~130~~136)
$$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (~~131~~137)
$$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6 \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (~~132~~138)
$$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6 \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473 \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (~~133~~139)
$$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473 \angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473 \angle -39.2°\ A$$

Example Calculations: Options 11 and 12

To satisfy the 130% margin in Options 11 and12:

Eq. (~~134~~140)
$$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2° \; A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2° \; A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes ~~that~~ the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (~~135~~141)
$$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60 \; MVA}{1.73 \times 13.8 \; kV}$$

$$I_{pri} = 2510.2 \; A$$

Secondary current (I_{sec}):

Eq. (~~136~~142)
$$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2 \; A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51 \text{ A}$$

To satisfy the 150% margin in Options 13a:

Eq. (~~137~~143)
$$I_{\sec limit} > I_{sec} \times 150\%$$

Example Calculations: Options 13a and 13b

$$I_{sec\,limit} > 2.51\ A \times 1.50$$

$$I_{sec\,limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is ~~applying~~protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (~~138~~144)
$$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~139~~145)
$$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the ~~high side~~line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (~~140~~146)
$$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Example Calculations: Option 14a

Apparent power (S):

Eq. (~~141~~147) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}):

Eq. (~~142~~148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~143~~149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (~~144~~150) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Example Calculations: Option 14a

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (~~145~~151)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283 \angle 85.0°\ \Omega$$

Example Calculations: Option 14b

Option 14b represents the simulation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that~~connected to synchronous generation. In this example, the Element is ~~applying~~protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

In this simulation the following values are derived:

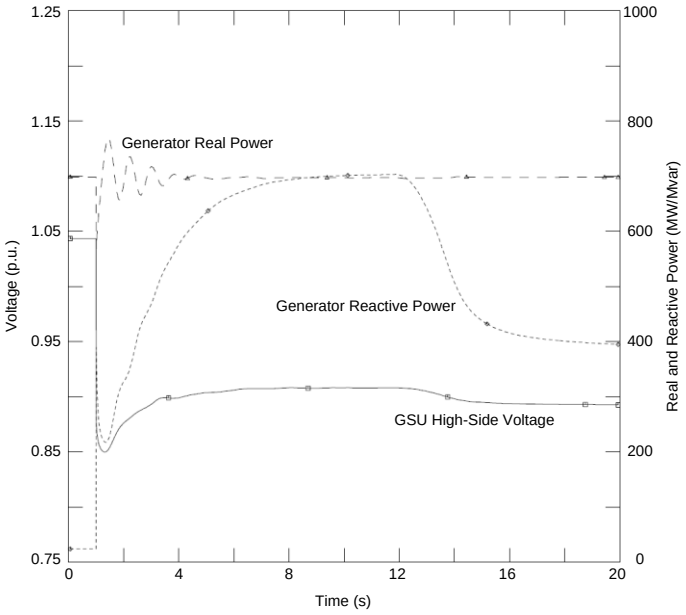
$$Q = 703.6\ Mvar$$

Example Calculations: Option 14b

$$~~V_{bus}~~V_{bus_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (~~146~~152)
$$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Primary impedance (Z_{pri}):

Eq. (~~147~~153)
$$Z_{pri} = \frac{~~\frac{V_{bus}^2}{S^*}~~}{} \frac{V_{bus_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$$

Example Calculations: Option 14b

$$Z_{pri} = 98.90\angle 45.1° \, \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~148~~154)
$$Z_{sec} = Z_{pri} \times \frac{CT_{ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 98.90\angle 45.1° \, \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\angle 45.1° \, \Omega \times 0.2$$

$$Z_{sec} = 19.78\angle 45.1° \, \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (~~149~~155)
$$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{19.78\angle 45.1° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 17.20\angle 45.1° \, \Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (~~150~~156)
$$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{17.20 \, \Omega}{\cos(85.0° - 45.1°)}$$

$$Z_{max} < \frac{17.20 \, \Omega}{0.767}$$

$$Z_{max} < 22.42\angle 85.0° \, \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ connected to synchronous generation. Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or ~~Phase~~phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —installed on the high-side of the GSU transformer~~,~~ and remote end of the line. Option 16a represents applying a phase directional ~~time overcurrent relay or Phase directional~~instantaneous overcurrent supervisory ~~elements (~~element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —directional toward the Transmission system– installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line.

~~This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer.~~Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer. The 0.85 per unit of the line nominal voltage at the relay location will be at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (~~151~~157)
$$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~152~~158)
$$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Example Calculations: Options 15a and 16a

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the ~~high side~~line nominal voltage:

Eq. (~~153~~159)
$$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (~~154~~160)
$$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157 \angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (~~155~~161)
$$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1157 \angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6 \angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (~~156~~162)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio_hv}}$$

$$I_{sec} = \frac{2280.6 \angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and ~~15b~~16a:

Eq. (~~157~~163)
$$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

Example Calculations: Options 15a and 16a

$$I_{sec\,limit} > 5.701 \angle -52.8° \; A \times 1.15$$

$$I_{sec\,limit} > 6.56 \angle -52.8° \; A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903 \; MVA \times 0.85$$

$$P = 767.6 \; MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6 \; MW$$

$$Q = 921.12 \; Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus_remote_substation} = 0.85 \; p.u. \times V_{nom}$$

$$V_{bus_remote_substation} = 0.85 \times 345 \; kV$$

$$V_{bus_remote_substation} = 293.25 \; kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0 \; MW + j921.12 \; Mvar$$

$$S = 1157 \angle 52.8° \; MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus_remote_substation}}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio_remote_bus}}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 5.701 \angle -52.8°\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 6.56 \angle -52.8°\ A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ connected to synchronous generation. Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or ~~Phase~~phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —installed on the high-side of the GSU transformer~~.~~ and remote end of the line. Option 16b represents applying a phase directional ~~time overcurrent relay or Phase directional~~instantaneous overcurrent supervisory ~~elements (~~element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —directional toward the Transmission system– installed on the high-side of the GSU and at the remote end of the line and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU and remote end of the line.

~~This example uses Option 15b as a simulation example~~Example calculations are provided for the case, where PTs and CTs are located at the remote end of the line from the plant. The 0.85 per unit of the line nominal voltage is applied at the remote end of the line.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the ~~in the~~ high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.~~

In this simulation the following values are derived:

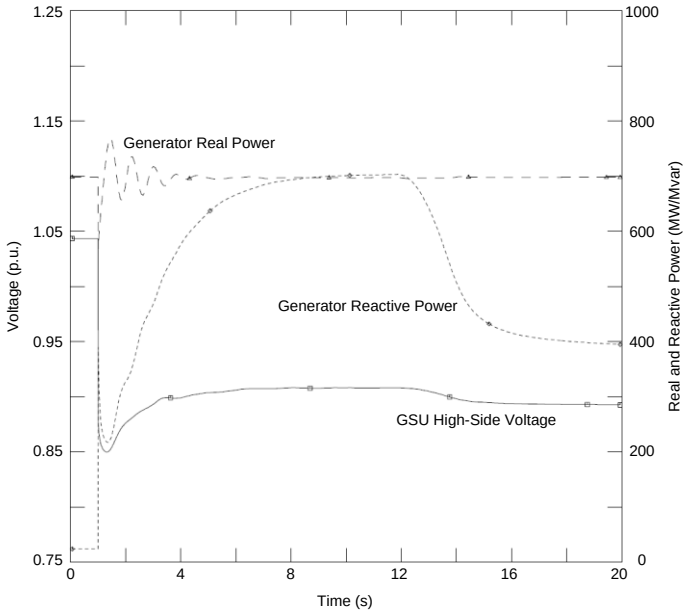
$$Q = 703.6\ Mvar$$

$$~~V_{bus}~~V_{bus_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Example Calculations: Options 15b and 16b



Apparent power (S):

Eq. (~~158~~171)
$$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

Primary current (I_{pri}):

Eq. (~~159~~172)
$$I_{pri} = \frac{\cancel{S^*}}{\cancel{\sqrt{3} \times V_{bus}}} \frac{S^*}{\sqrt{3} \times V_{bus_simulated}}$$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

$$I_{pri} = 1831.2\angle -45.1°\ A$$

Secondary current (I_{sec}):

Eq. (~~160~~173)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio_hv}}$$

Example Calculations: Options 15b and 16b

$$I_{sec} = \frac{1831.2\angle -45.1° \; A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578 \angle -45.1° \; A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (~~161~~174)
$$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 4.578 \angle -45.1° \; A \times 1.15$$

$$I_{\text{sec}\,limit} > 5.265 \angle -45.1° \; A$$

Example Calculations: Option 17

Option 17 represents the calculation for ~~three asynchronous generation~~ Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21)~~–~~ directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~162~~175)
$$P_{Asynch} = \; 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \; MVA \; \times 0.85$$

$$P_{Asynch} = 102.0 \; MW$$

Reactive Power output (Q):

Eq. (~~163~~176)
$$Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q_{Asynch} = 15 \; Mvar + 5 \; Mvar + (3 \times 40 \; MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \; Mvar$$

Example Calculations: Option 17

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the ~~high side~~line nominal voltage for the bus voltage (V_{bus}):

Eq. (~~164~~177)
$$V_{bus} = 1.0\ p.u. \times V_{nom}$$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (~~165~~178)
$$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~166~~179)
$$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~167~~180)
$$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

Example Calculations: Option 17

To satisfy the 130% margin in Option 17:

Eq. (~~168~~181)
$$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, and then the maximum allowable impedance reach is:

Eq. (~~169~~182)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for ~~three generation~~relays on Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that is~~. Option 18 represents applying a phase time overcurrent (e.g., 51) ~~relay connected to three asynchronous generators.~~ and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional ~~time~~ overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer and remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Options 18 and 19

Real Power output (P):

Eq. (~~170~~183)
$$P = 3 \times GEN_{Asych_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~171~~184)
$$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the ~~high side~~line nominal voltage (V_{bus}):

Eq. (~~172~~185)
$$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (~~173~~186)
$$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (~~174~~187)
$$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

Example Calculations: Options 18 and 19

$$I_{pri} = 220.5 \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (~~175~~188)
$$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio_hv}}$$

$$I_{sec} = \frac{220.5 \angle -39.2° \, A}{\frac{300}{5}}$$

$$I_{sec} = 3.675 \angle -39.2° \, A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (~~176~~189)
$$I_{\text{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\text{sec}\,limit} > 3.675 \angle -39.2° \, A \times 1.30$$

$$I_{\text{sec}\,limit} > 4.778 \angle -39.2° \, A$$

End of calculations

Rationale:

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

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

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Implementation Plan

Project 2016-04 – Modifications to PRC-025-1

Requested Approvals

- PRC-025-2 – Generator Relay Loadability

Requested Retirements

- PRC-025-1 – Generator Relay Loadability

Prerequisite Approvals

- None.

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Terms in the NERC Glossary of Terms

- No definitions are proposed as a part of this standard.

Background

The Reliability Standard PRC-025-1 went into effect in the United States on October 1, 2014 under a phased implementation plan based on two time frames. The first timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider to apply settings to its existing load-responsive protective relays that are capable of meeting the standard while maintaining reliable fault protection. The second and extended timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider that determined its existing load-responsive protective relays require replacement or removal. The PRC-025-1 standard drafting team recognized that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment or that removal of the load-responsive protective relay is the best alternative to satisfy the entity's protection criteria and meet the requirements of PRC-025-1.

General Considerations

The PRC-025-2 standard drafting team considered the scope of the proposed revisions and the timing for regulatory approvals with respect to the version one enforcement dates. The first U.S. enforcement date of October 1, 2019 applies to load-responsive protective relays where the applicable entity will be making a setting change to meet the setting criteria of the standard while maintaining reliable fault protection. The second U.S. enforcement date of October 1, 2021 applies to load-responsive protective relays where

the applicable entity will be removing or replacing the relay to meet the setting criteria of the standard while maintaining reliable fault protection.

The PRC-025-2 Implementation Plan reflects consideration of the following:

- The proposed Option 5b reduces the implementation burden to the applicable entities.
- The proposed revisions to Options 14a, 14b, 15a, 15b, 16a, 16b, 17, 18, and 19 may give reason for entities to re-evaluate their settings for load-responsive protective relays.
- A few proposed Option(s) now include the 50 element.

Effective Date

PRC-025-2

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Effective Date and Phased-In Compliance Dates

Load-responsive protective relays subject to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider shall not be required to comply with Requirement R1 until the following dates after the effective date of Reliability Standard PRC-025-2:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 12 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 36 months after the effective date of Reliability Standard PRC-025-2

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including but

not limited to changes in NERC Registration Criteria or Bulk Electric System (BES) definition, shall not be required to comply with Requirement R1 until the following dates:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months beyond the date the load-responsive protective relays become applicable to the standard

Retirement Date

- PRC-025-1
  Reliability Standard PRC-025-1 shall be retired immediately prior to the effective date of PRC-025-2 in the particular jurisdiction in which the revised standard is becoming effective.

Phased-In Retirement

- None.

Implementation Plan for Definitions

- No definitions are proposed as a part of this standard.

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Violation Risk Factor and Violation Severity Level Justifications

PRC-025-2 – Generator Relay Loadability

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-025 – Generator Relay Loadability. Note that no Requirement, Measure, or VRF/VSL changes have been made in this proposed PRC-025-2 Reliability Standard.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Reliability Coordination Standard Drafting Team (SDT) applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or

restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline 1 – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors 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:[2]

- 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

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline 2 – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline 3 – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors 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 Violation Risk Factor 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 – Violation Severity Levels

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.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's 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 and VSL Justifications

VRF Justifications – PRC-025-2, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-2, Attachment 1; Relay Settings, 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. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a “High” VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a “High” VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.

VRF Justifications – PRC-025-2, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-025-2, R1				
R1	**Lower**	**Moderate**	**High**	**Severe**
R1	N/A	N/A	N/A	The Generator Owner, Transmission Owner, or Distribution Provider did not apply settings in accordance with PRC-025-2 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.
VSL Justifications – PRC-025-2, R1				
NERC VSL Guidelines				The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance				The VSL is not changing from the current approved version; therefore, there is no lowering the current level of compliance.

Proposed VSLs for PRC-025-2, R1	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be "Severe" in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent 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 addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on "an applied load-responsive protective relay" in accordance with Attachment 1: Relay Settings.

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

Anticipated Actions	Date
30-day informal comment period with ballot	April 2017
45-day formal comment period with additional ballot	July 2017
45-day formal comment period with additional ballot	October 2017
10-day final ballot	December 2017
Board adoption	February 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):

~~Text~~ 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:** **See Implementation Plan.** ~~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.~~

~~6. 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.~~

~~7. 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:~~

~~8. P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)~~

~~9. P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)~~

~~10. P2-1~~

~~11. P2-2 (above 300 kV)~~

~~12. P2-3 (above 300 kV)~~

~~13. P3-1 through P3-5~~

~~14. P4-1 through P4-5 (above 300 kV)~~

~~15.~~5. ~~P5 (above 300 kV)~~

~~16. Background: Text (DELETE GREEN TEXT PRIOR TO PUBLISHING) This section is to only be used for standards that currently have a background section. Going forward standard drafting teams should avoid using this section.~~

~~17. Standard-Only Definition: Text (DELETE GREEN TEXT PRIOR TO PUBLISHING) This section is to only be used for standards that currently have standard only definitions. Going forward a standard must provide a justification as to why the standard needs a standard-only definition and cannot be moved to the NERC Glossary of Terms.~~

B. Requirements and Measures

Rationale for Requirement R1:

References to MOD-010 and MOD-012 in Requirement R1 have been replaced with MOD-032, which is now the applicable standard to assemble the network modeling data necessary to meet the TPL-001 requirements. MOD-032-1 superseded MOD-010 and MOD-012, which were retired on 6/30/2016 in the United States.

Rationale for Requirement R1 Part 1.1.2:

In Order 786, Federal Energy Regulatory Commission (FERC) directed 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" (P 40). The Commission clarified that its directive is to "include known generator and transmission planned maintenance outages in planning assessments, not hypothetical planned outages" (P 42). FERC stated that NERC had flexibility in addressing the identified concerns and outlined three acceptable approaches, that include:

1. "eliminating the six-month threshold altogether";
2. "decreasing the threshold to fewer months to include additional significant planned outages"; or
3. "including parameters on what constitutes a significant planned outage based for example on MW or facility ratings."

See Order No. 786 at P 43.

Order 786 includes the following additional concerns:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods (*see* P 41);
- Planned outages during those times should be considered to allow for a single element to be taken out of service without compromising the ability to meet demand (*see* P 41);
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability (*see* P 41);
- Planned outages are not "hypothetical outages" and should not be treated as multiple contingencies in the planning standard (should be addressed in N-0 base case) (*see* P 42);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages (*see* P 44);
- The Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two, and year five, and known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon (*see* P 45).

The change to Requirement 1 Part 1.1.2 eliminates the specified 6 month outage duration and provides the opportunity for the Reliability Coordinator to assist the Planning Coordinator and/or Transmission Planner to determine which known outages, if any, need to be considered in the Planning Assessment for the Near-Term.

Note: The drafting team points out that this is coordination of known outages beyond the Operations Planning.

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~~MOD-032 -standard~~s~~, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) ~~with a duration of at least six months~~ 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 ~~R.~~ 2.4.3.

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-010 and MOD-012,~~ 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.

Rationale for Requirement R2 Part 2.4.5:

In Order No. 786, FERC stated that it believed a stability analysis for spare equipment strategy should exist, similar to the steady state analysis under TPL-001-4 Requirement 2 Part 2.1.5 (*see* P 89). The SDT modified the standard to add R2.4.5, which includes similar language to that used for the steady-state analysis under R2.1.5.

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, as selected in consultation with the ~~as directed~~ Reliability Coordinator, with ~~the~~ known outages modeled as specified in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish

this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

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

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

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

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

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

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

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

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

2.4.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

~~2.4.3.~~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.

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 studied. The studies shall be performed for the 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.

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

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

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

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

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

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

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

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

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the

Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

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

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

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

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

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.

Rationale for Requirement R4 Part 4.6:

The SPF of a non-redundant Protection System component is a relevant reliability concern for the electrical utility industry and have been identified as the cause of significant system disturbances in past years. (*See Industry Advisory-Protection System Single Point*

of Failure, Informational Filing of the North American Electric Reliability Corporation in Response to Order No. 754, Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request). The changes herein clearly establish the TPL-001 standard as requiring corrective actions for Planning Events for which a single point of failure of a non-redundant component of a Protection System, as described by footnote 13. The drafting team took into consideration the recent history of attention given to single point of failure and the tradeoffs with incorporating the 3Ø fault with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing into the existing P5 or similar, Table 1 event. Consistent with the concerns expressed in FERC Order No. 754, the drafting team decided to maintain the 3Ø fault event in the extreme event section of Table 1, while incorporating a specific Requirement R4 Part 4.6 to develop Corrective Action Plan when analysis concludes that Cascading is caused. By featuring the extreme events 2e-2h listed from the stability column of Table 1 in Requirement 4 Part 4.6, this highlights the single point of failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing as having higher risk than other extreme events, but only demanding corrective action if observed to cause Cascading. This is a reasonable balance of likelihood of the event and its consequences. In this way, the drafting team intends for the extreme events 2e-2h listed from the stability column of Table 1 that cause Cascading to require correction, most likely through Protection System modifications, not simply be evaluated for possible actions designed to reduce the likelihood or mitigate the consequences of the extreme event, in accordance with Requirement R4 Part 4.5.

A planner is permitted to use engineering judgment to select the Protection System component failures for evaluation that would produce the more severe system results or impact, and the evaluation would address all Protection Systems affected by the selected component. A Protection System component failure that impacts one or more Protection Systems and increases the total fault clearing time requires a planner to simulate the full impact (clearing time and facilities removed) on Bulk Electric System performance.

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

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

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

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

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

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

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

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

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

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

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

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

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

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to

ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

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

4.6. If the analysis concludes there is Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h, a Corrective Action Plan shall be developed. The Corrective Action Plan shall:

4.6.1. List ~~s~~System deficiencies and the associated actions needed to prevent the ~~s~~System from Cascading.

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

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

~~17.1.~~1.1. Compliance Enforcement Authority:

~~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.

~~17.2.~~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 M7 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.

~~17.3.~~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.

~~17.4.~~

~~17.5.~~

~~17.6.~~1.4. ~~1.2~~ **Compliance Monitoring Period and Reset Timeframe:**

Not applicable.

~~17.7.~~

~~17.8.~~1.5. ~~**Compliance Monitoring and Enforcement Processes:**~~

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~**17.9.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.~~

~~17.10.~~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~~ 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.
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. 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 P7) 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 P7) 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 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. OR The responsible entity did not develop a Corrective Action Plan as described in Requirement R4, Part 4.6.	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.
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.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents. **(DELETE GREEN TEXT PRIOR TO PUBLISHING) A link should be added to the implementation plan and other important documents associated with the standard once finalized.**

Rationale for Table 1 P5 Event and Footnote 13:

The revisions to Table 1 Category P5 event require an entity to model a single point of failure of a non-redundant Protection System component that may prevent correct operation of a Protection System, including other Protection Systems impacted by that failed component based on the as-built design of that Protection System. The evaluation shall address all Protection Systems affected by the failed component and the increases (if any) of the total fault clearing time. Footnote 13 provides the attributes of the specific system component failure that the entity shall consider for evaluation.

Changes to the Table 1 P5 event and related footnote 13 are driven by subsequent results of an assessment of Protection System single points of failure in response to FERC Order No. 754. In paragraph 19 of Order No. 754, FERC stated that there is "an issue concerning the study of the non-operation of non-redundant primary Protection Systems; e.g., the study of a single point of failure on Protection Systems." NERC subsequently issued a NERC Section 1600 Request for Data or Information, the results of which were analyzed by the System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS). In their 2015 report "*Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request*," the SPCS and SAMS considered a variety of alternatives to address the reliability risk posed by single points of failure. SPCS and SAMS concluded that the most appropriate recommendation aligning with Order No. 754 directives and maximizing reliability of Protection System performance included modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process.

The SPCS/SAMS report made the recommendations to replace “relay” with “component of a Protection System” in the Table 1 P5 event and replace footnote 13 in TPL-001-4 with alternate wording: “The components from the definition of Protection System for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.”

This revision to footnote 13 clarifies the components of the Protection System that must be considered when simulating delayed fault clearing due to the failure of a non-redundant component of a Protection System. The SPCS/SAMS report described voltage or current sensing devices as having a lower level of risk of failure to trip due to robustness and likelihood to actually cause tripping upon failure. Therefore, these components of a Protection System are omitted from footnote 13.

The drafting team sought to limit the scope of protective relays which respond to electrical quantities that may be considered non-redundant components of a Protection System that may experience a single point of failure to those relays that are used for primary protection at the local terminal and applied over the element in question. As typical Protection System designs implement backup protective relaying locally and remotely, the drafting team did not include backup protective relays or overlapping zonal protection as components of a Protection System specified in footnote 13.

Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. The drafting team augmented the SAMS/SPCS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that Protection System is required to achieve Transmission System Planning Performance Requirements, enumerated in Table 1 of TPL-

001-5. In other words, a communication-aided Protection System that may experience a SPF, causing it to operate improperly or not at all, must be considered as part of non-redundancy. The drafting team concluded that the failure of communication-aided Protection Systems may take many forms; however, by alarming and monitoring these systems, the overall risk of impact to the Bulk Electric System is reduced to an acceptable level. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. This alarm monitoring is similar to the requirement associated with station DC supplies. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL-001-5 standard.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

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

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

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

d. Simulate Normal Clearing unless otherwise specified.

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

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

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

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

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

Stability Only:

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

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

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

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~~ 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

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 fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. f. 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.	g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. ~~d.~~i. 3Ø internal breaker fault. ~~e.~~j. 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:
    1. A single protective relay
    2. A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported
    3. 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
    4. A single control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices ~~Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).~~

Attachment 1

I. Stakeholder Process

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

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

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

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

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

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

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

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

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

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

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees.	

Version	Date	Action	Change Tracking
		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.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual

VERSION ~~3~~4

Effective: ~~June 26, 2013~~TBD

to ensure the reliability of the bulk power system

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Section 1.0: Introduction

1.1: Authority
This manual is published by the authority of the NERC Board of Trustees. The Board of Trustees, as necessary to maintain NERC's certification as the Electric Reliability Organization ("ERO"), may file the manual with Applicable Governmental Authorities for approval as an ERO document. When approved, the manual is appended to and provides implementation detail in support of the ERO Rules of Procedure Section 300 — Reliability Standards Development.

Capitalized terms not otherwise defined herein, shall have the meaning set forth in the Definitions Used in the Rules of Procedure, Appendix 2 to the Rules of Procedure.

1.2: Scope
The policies and procedures in this manual shall govern the activities of the North American Electric Reliability Corporation ("NERC") related to the development, approval, revision, reaffirmation, and withdrawal of Reliability Standards, Interpretations, Violation Risk Factors ("VRFs"), Violation Severity Levels ("VSLs"), definitions, Variances, and reference documents developed to support standards for the Reliable Operation and planning of the North American Bulk Power Systems.

This manual also addresses the role of the Standards Committee, drafting team and ballot body in the development and approval of Compliance Elements in conjunction with standard development.

1.3: Background
NERC is a nonprofit corporation formed for the purpose of becoming the North American ERO. NERC works with all stakeholder segments of the electric industry, including electricity users, to develop Reliability Standards for the reliability planning and Reliable Operation of the North American Bulk Power Systems. In the United States, the Energy Policy Act of 2005 added Section 215 to the Federal Power Act for the purpose of establishing a framework to make Reliability Standards mandatory for all Bulk Power System owners, operators, and users. Similar authorities are provided by Applicable Governmental Authorities in Canada. NERC was certified as the ERO effective July 2006. *North American Electric Reliability Corp*., 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007).

1.4: Essential Attributes of NERC's Reliability Standards Processes
NERC's Reliability Standards development processes provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing a proposed Reliability Standard consistent with the attributes necessary for American National Standards Institute ("ANSI") accreditation. The same attributes, as well as transparency, consensus-building, and timeliness, are also required under the ERO Rules of Procedure Section 304.

- ***Open Participation***
  Participation in NERC's Reliability Standards development balloting and approval processes shall be open to all entities materially affected by NERC's Reliability Standards. There shall be no financial barriers to participation in NERC's Reliability Standards balloting and approval processes. Membership in the Registered Ballot Body shall not be conditional upon membership in any organization, nor unreasonably restricted on the basis of technical qualifications or other such requirements.

- ***Balance***
  NERC's Reliability Standards development processes shall not be dominated by any two interest categories, individuals, or organizations and no single interest category, individual, or organization is able to defeat a matter.

  NERC shall use a voting formula that allocates each industry Segment an equal weight in determining the final outcome of any Reliability Standard action. The Reliability Standards development processes shall have a balance of interests. Participants from diverse interest categories shall be encouraged to join the Registered Ballot Body and participate in the balloting process, with a goal of achieving balance between the interest categories. The Registered Ballot Body serves as the consensus body voting to approve each new or proposed Reliability Standard, definition, Variance, and Interpretation.

- ***Coordination and harmonization with other American National Standards activities***
  NERC is committed to resolving any potential conflicts between its Reliability Standards development efforts and existing American National Standards and candidate American National Standards.

- ***Notification of standards development***
  NERC shall publicly distribute a notice to each member of the Registered Ballot Body, and to each stakeholder who indicates a desire to receive such notices, for each action to create, revise, reaffirm, or withdraw a Reliability Standard, definition, or Variance; and for each proposed Interpretation. Notices shall be distributed electronically, with links to the relevant information, and notices shall be posted on NERC's Reliability Standards web page. All notices shall identify a readily available source for further information.

- ***Transparency***
  The process shall be transparent to the public.

- ***Consideration of views and objections***
  Drafting teams shall give prompt consideration to the written views and objections of all participants as set forth herein. Drafting teams shall make an effort to resolve each objection that is related to the topic under review.

- ***Consensus Building***
  The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

- ***Consensus vote***
  NERC shall use its voting process to determine if there is sufficient consensus to approve a proposed Reliability Standard, definition, Variance, or Interpretation. NERC shall form a ballot pool for each Reliability Standard action from interested members of its Registered Ballot Body. Approval of any Reliability Standard action requires:

  - A quorum, which is established by at least 75% of the members of the ballot pool submitting a response excluding unreturned ballots; and
  - A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast during all stages of balloting except the final ballot is the sum of affirmative and negative votes with comments, excluding abstentions, non-responses, and negative votes without comments. During the final ballot, the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

- ***Timeliness***
  Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

- ***Metric Policy***
  The International System of units is the preferred units of measurement in NERC Reliability Standard. However, because NERC's Reliability Standards apply in Canada, the United States and portions of Mexico, where applicable, measures are provided in both the metric and English units.

1.5: Ethical Participation

All participants in the NERC Standard development process, including drafting teams, quality reviewers, Standards Committee members and members of the Registered Ballot Body, are obligated to act in an ethical manner in the exercise of all activities conducted pursuant to the terms and conditions of the Standard Processes Manual and the standard development process.

Section 2.0: Elements of a Reliability Standard

2.1: Definition of a Reliability Standard

A Reliability Standard includes a set of Requirements that define specific obligations of owners, operators, and users of the North American Bulk Power Systems. The Requirements shall be material to reliability and measurable. A Reliability Standard is defined as follows:

> "Reliability Standard" means a requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk Power System., ~~including without limiting the foregoing,~~ The term includes requirements for the operation of existing Bulk Power System ~~Facilities~~facilities, including cyber-security protection, and ~~including~~ the design of planned additions or modifications to such ~~Facilities~~ facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge ~~Bulk Power System~~such ~~Facilities~~ facilities or to construct new transmission capacity or generation capacity. (In certain contexts, this term may also refer to a "Reliability Standard" that is in the process of being developed, or not yet approved or recognized by FERC or an applicable governmental authority in other jurisdictions). ~~A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.~~ *See* Appendix 2 to the NERC Rules of Procedure, Definitions Used in the Rules of Procedure.

2.2: Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American Bulk Power Systems.[1] Each Reliability Standard shall enable or support one or more of the reliability principles, thereby ensuring that each Reliability Standard serves a purpose in support of reliability of the North American Bulk Power Systems. Each Reliability Standard shall also be consistent with all of the reliability principles, thereby ensuring that no Reliability Standard undermines reliability through an unintended consequence.

2.3: Market Principles

Recognizing that Bulk Power System reliability and electricity markets are inseparable and mutually interdependent, all Reliability Standards shall be consistent with the market interface principles.[2] Consideration of the market interface principles is intended to ensure that Reliability Standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

2.4: Types of Reliability Requirements

Generally, each Requirement of a Reliability Standard shall identify what Functional Entities shall do, and under what conditions, to achieve a specific reliability objective. Although Reliability Standards all follow this format, several types of Requirements may exist, each with a different approach to measurement.

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[1] The intent of the set of NERC Reliability Standards is to deliver an adequate level of reliability. The latest set of reliability principles and the latest set of characteristics associated with an adequate level of reliability are posted on the Reliability Standards Resources web page.

[2] The latest set of market interface principles is posted on the Reliability Standards Resources web page.

- **Performance-based Requirements** define a specific reliability objective or outcome achieved by one or more entities that has a direct, observable effect on the reliability of the Bulk Power System, *i.e.* an effect that can be measured using power system data or trends. In its simplest form, a performance-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome.*

- **Risk-based Requirements** define actions by one or more entities that reduce a stated risk to the reliability of the Bulk Power System and can be measured by evaluating a particular product or outcome resulting from the required actions. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the Bulk Power System.*

- **Capability-based Requirements** define capabilities needed by one or more entities to perform reliability functions and can be measured by demonstrating that the capability exists as required. A capability-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the Bulk Power System.*

The body of reliability Requirements collectively provides a defense-in-depth strategy supporting reliability of the Bulk Power System.

2.5: Elements of a Reliability Standard

A Reliability Standard includes several components designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the Bulk Power System.

The components of a Reliability Standard may include the following:

Title: A brief, descriptive phrase identifying the topic of the Reliability Standard.

Number: A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the Reliability Standards.[3]

Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard.

Applicability: Identifies which entities are assigned reliability requirements. The specific Functional Entities and Facilities to which the Reliability Standard applies.

Effective Dates: Identification of the date or pre-conditions determining when each Requirement becomes effective in each jurisdiction.

Requirement: An explicit statement that identifies the Functional Entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement for which compliance is mandatory.

[3] Reliability Standards shall be numbered in accordance with the NERC Standards Numbering Convention as provide on the Reliability Standards Resources web page.

Compliance Elements: Elements to aid in the administration of ERO compliance monitoring and enforcement responsibilities.[4]

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

- ***Violation Risk Factors and Violation Severity Levels:*** Violation risk factors (VRFs) and violation severity levels (VSLs) are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved reliability standard.[5] Each requirement in each reliability standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NERC Staff, at the same time as the associated reliability standard, but are not part of the reliability standard. The Board of Trustees is responsible for approving VRFs and VSLs.

  - ***Violation Risk Factors***
    VRFs identify the potential reliability significance of noncompliance with each requirement. Each requirement is assigned a VRF in accordance with the latest approved set of VRF criteria.[6]

  - ***Violation Severity Levels***
    VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria.[7]

Version History: The version history is provided for informational purposes and lists information regarding prior versions of Reliability Standards.

Variance: A Requirement (to be applied in the place of the continent-wide Requirement) that is applicable to a specific geographic area or to a specific set of Registered Entities.

Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated Reliability Standard. The Compliance Enforcement Authority will be NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

***Application guidelines*:** Guidelines to support the implementation of the associated Reliability Standard.

***Procedures*:** Procedures to support implementation of the associated Reliability Standard.

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[4] It is the responsibility of the ERO staff to develop compliance tools for each standard; these tools are not part of the standard but are referenced in this manual because the preferred approach to developing these tools is to use a transparent process that leverages the technical and practical expertise of the drafting team and ballot pool..
[5] The *Sanction Guidelines of the North American Electric Reliability Corporation* identifies the factors used to determine a penalty or sanction for violation of reliability standard and is posted on the NERC Web Site.
[6] The latest set of approved VRF Criteria is posted on the Reliability Standards Resources Web Page.
[7] The latest set of approved VSL Criteria is posted on the Reliability Standards Resources Web Page.

The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.

Section 3.0: Reliability Standards Program Organization

3.1: Board of Trustees

The NERC Board of Trustees shall consider for adoption Reliability Standards, definitions, Variances and Interpretations and associated implementation plans that have been processed according to the processes identified in this manual. Once the Board adopts a Reliability Standard, definition, Variance or Interpretation, the Board shall direct NERC Staff to file the document(s) for approval with Applicable Governmental Authorities.

3.2: Registered Ballot Body

The Registered Ballot Body comprises all entities or individuals that qualify for one of the Segments approved by the Board of Trustees[8], and are registered with NERC as potential ballot participants in the voting on Reliability Standards. Each member of the Registered Ballot Body is eligible to join the ballot pool for each Reliability Standard action.

3.3: Ballot Pool

Each Reliability Standard action has its own ballot pool formed of interested members of the Registered Ballot Body. The ballot pool comprises those members of the Registered Ballot Body that respond to a pre-ballot request to participate in that particular Reliability Standard action. The ballot pool votes on each Reliability Standards action. The ballot pool remains in place until all balloting related to that Reliability Standard action has been completed.

3.4: Standards Committee

The Standards Committee serves at the pleasure and direction of the NERC Board of Trustees, and the Board approves the Standards Committee's Charter.[9] Standards Committee members are elected by their respective Segment's stakeholders. The Standards Committee consists of two members of each of the Segments in the Registered Ballot Body.[10] A member of the NERC Reliability Standards Staff shall serve as the non-voting secretary to the Standards Committee.

The Standards Committee is responsible for managing the Reliability Standards processes for development of Reliability Standards, definitions, Variances and Interpretations in accordance with this manual. The responsibilities of the Standards Committee are defined in detail in the Standards Committee's Charter. The Standards Committee is responsible for ensuring that the Reliability Standards, definitions, Variances and Interpretations developed by drafting teams are developed in accordance with the processes in this manual and meet NERC's benchmarks for Reliability Standards as well as criteria for governmental approval.[11]

The Standards Committee has the right to remand work to a drafting team, to reject the work of a drafting team, or to accept the work of a drafting team. The Standards Committee may disband a drafting team if it determines (a) that the drafting team is not producing a standard in a timely manner; (b) the drafting team

[8] The industry Segment qualifications are described in the Development of the Registered Ballot Body and Segment Qualification Guidelines document posted on the Reliability Standards Resources web page and are included in Appendix 3D of the NERC Rules of Procedure.

[9] The Standards Committee Charter is posted on the Reliability Standards Resources web page.

[10] In addition to balanced Segment representation, the Standards Committee shall also have representation that is balanced among countries based on Net Energy for Load ("NEL"). As needed, the Board of Trustees may approve special procedures for the balancing of representation among countries represented within NERC.

[11] The Ten Benchmarks of an Excellent Reliability Standard and FERC's Criteria for Approving Reliability Standards are posted on the Reliability Standards Resources web page.

is not able to produce a standard that will achieve industry consensus; (c) the drafting team has not addressed the scope of the SAR; or (d) the drafting team has failed to fully address a regulatory directive or otherwise provided a responsive or equally efficient and effective alternative. The Standards Committee may direct a drafting team to revise its work to follow the processes in this manual or to meet the criteria for NERC's benchmarks for Reliability Standards, or to meet the criteria for governmental approval; however, the Standards Committee shall not direct a drafting team to change the technical content of a draft Reliability Standard.

The Standards Committee shall meet at regularly scheduled intervals (either in person, or by other means). All Standards Committee meetings are open to all interested parties.

3.5: NERC Reliability Standards Staff

The NERC Reliability Standards Staff, led by the Director of Standards, is responsible for administering NERC's Reliability Standards processes in accordance with this manual. The NERC Reliability Standards Staff provides support to the Standards Committee in managing the Reliability Standards processes and in supporting the work of all drafting teams. The NERC Reliability Standards Staff works to ensure the integrity of the Reliability Standards processes and consistency of quality and completeness of the Reliability Standards. The NERC Reliability Standards Staff facilitates all steps in the development of Reliability Standards, definitions, Variances, Interpretations and associated implementation plans.

The NERC Reliability Standards Staff is responsible for presenting Reliability Standards, definitions, Variances, and Interpretations to the NERC Board of Trustees for adoption. When presenting Reliability Standards-related documents to the NERC Board of Trustees for adoption or approval, the NERC Reliability Standards Staff shall report the results of the associated stakeholder ballot, including identification of unresolved stakeholder objections and an assessment of the document's practicality and enforceability.

3.6: Drafting Teams

The Standards Committee shall appoint industry experts to drafting teams to work with stakeholders in developing and refining Standard Authorization Requests ("SARs"), Reliability Standards, definitions, and Variances. The NERC Reliability Standards Staff shall appoint drafting teams that develop Interpretations. The NERC Reliability Standards Staff shall provide, or solicit from the industry, essential support for each of the drafting teams in the form of technical writers, legal, compliance, and rigorous and highly trained project management and facilitation support personnel.

Each drafting team may consist of a group of technical, legal, and compliance experts that work cooperatively with the support of the NERC Reliability Standards Staff.[12] The technical experts provide the subject matter expertise and guide the development of the technical aspects of the Reliability Standard, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the Reliability Standard. Each drafting team appointed to develop a Reliability Standard is responsible for following the processes identified in this manual as well as procedures developed by the Standards Committee from the inception of the assigned project through the final acceptance of that project by Applicable Governmental Authorities.

Collectively, each drafting team:

- Drafts proposed language for the Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.

[12] The detailed responsibilities of drafting teams are outlined in the Drafting Team Guidelines, which is posted on the Reliability Standards Resources web page.

- Develops and refines technical documents that aid in the understanding of Reliability Standards.
- Works collaboratively with NERC Compliance Monitoring and Enforcement Staff to develop Reliability Standard Audit Worksheets ("RSAWs") at the same time Reliability Standards are developed.
- Provides assistance to NERC Staff in the development of Compliance Elements of proposed Reliability Standards.
- Solicits, considers, and responds to comments related to the specific Reliability Standards development project.
- Participates in industry forums to help build consensus on the draft Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.
- Assists in developing the documentation used to obtain governmental approval of the Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.

All drafting teams report to the Standards Committee.

3.7: Governmental Authorities

The Federal Energy Regulatory Commission ("FERC") in the United States of America, and where permissible by statute or regulation, the federal or provincial governments of other North American jurisdictions that have recognized NERC as the ERO ~~each of the eight Canadian Provinces (Manitoba, Nova Scotia, Saskatchewan, Alberta, Ontario, British Columbia, New Brunswick and Quebec) and the National Energy Board of Canada~~ have the authority to approve each new, revised or withdrawn Reliability Standard, definition, Variance, VRF, VSL and Interpretation following adoption or approval by the NERC Board of Trustees.

3.8: Committees, Subcommittees, Working Groups, and Task Forces

NERC's technical committees, subcommittees, working groups, and task forces provide technical research and analysis used to justify the development of new Reliability Standards and provide guidance, when requested by the Standards Committee, in overseeing field tests or collection and analysis of data. The technical committees, subcommittees, working groups, and task forces provide feedback to drafting teams during both informal and formal comment periods.

The Standards Committee may request that a NERC technical committee or other group prepare a Technical document to support development of a proposed Reliability Standard.

The technical committees, subcommittees, working groups, and task forces share their observations regarding the need for new or modified Reliability Standards or Requirements with the NERC Reliability Standards Staff for use in identifying the need for new Reliability Standards projects for the three-year *Reliability Standards Development Plan*.

3.9: Compliance and Certification Committee

The Compliance and Certification Committee is responsible for monitoring NERC's compliance with its Reliability Standards processes and procedures and for monitoring NERC's compliance with the Rules of Procedure regarding the development of new or revised Reliability Standards, definitions, Variances, and Interpretations. The Compliance and Certification Committee may assist in verifying that each proposed Reliability Standard is enforceable as written before the Reliability Standard is posted for formal stakeholder comment and balloting.

3.10: Compliance Monitoring and Enforcement Program

As applicable, the NERC Compliance Monitoring and Enforcement Program Staff manages and enforces compliance with approved Reliability Standards. Compliance Monitoring and Enforcement Staff are responsible for the development of select compliance tools. The drafting team and the Compliance Monitoring and Enforcement Program Staff shall work together during the Reliability Standard development process to ensure an accurate and consistent understanding of the Requirements and their intent, and to ensure that applicable compliance tools accurately reflect that intent. The goal of this collaboration is to ensure that application of the Reliability Standards in the Compliance Monitoring and Enforcement Program by NERC and the Regional Entities is consistent.

The Compliance Monitoring and Enforcement Program is encouraged to share its observations regarding the need for new or modified Requirements with the NERC Reliability Standards Staff for use in identifying the need for new Reliability Standards projects.

3.11: North American Energy Standards Board ("NAESB")

While NERC has responsibility for developing Reliability Standards to support reliability, NAESB has responsibility for developing business practices and coordination between reliability and business practices as needed. NERC and NAESB developed and approved a procedure[13] to guide the development of Reliability Standards and business practices where the reliability and business practice components are intricately entwined within a proposed Reliability Standard.

[13] The NERC NAESB Template Procedure for Joint Standards Development and Coordination is posted on the Reliability Standards Resources web page.

Section 4.0: Process for Developing, Modifying, Withdrawing or Retiring a Reliability Standard

There are several steps to the development, modification, withdrawal or retirement of a Reliability Standard.[14]

The development of the *Reliability Standards Development Plan* is the appropriate forum for reaching agreement on whether there is a need for a Reliability Standard and the scope of a proposed Reliability Standard. A typical process for a project identified in the *Reliability Standards Development Plan* that involves a revision to an existing Reliability Standard is shown below. Note that most projects do not include a field test.

[14] The process described is also applicable to projects used to propose a new or modified definition or Variance or to propose retirement of a definition or Variance.

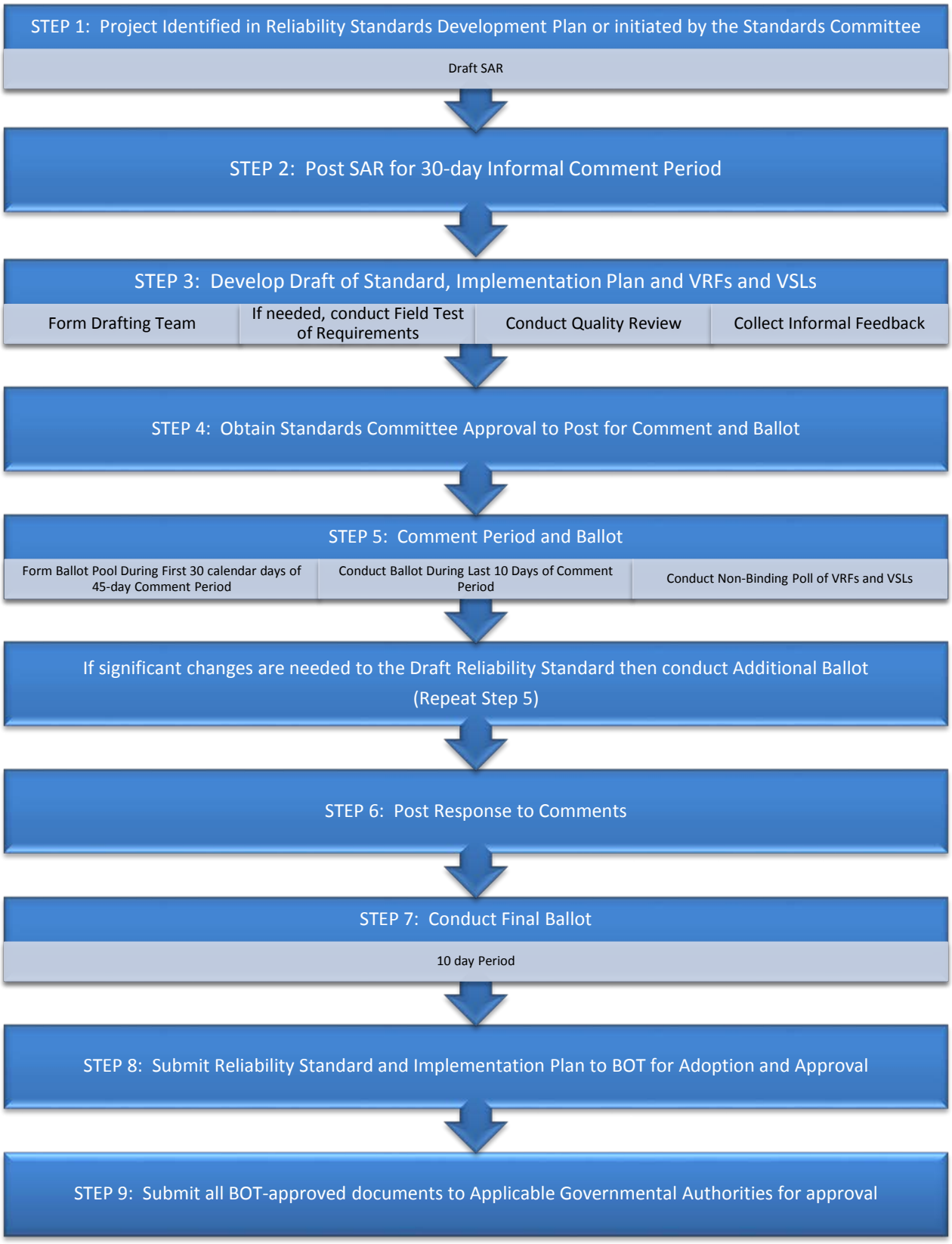


FIGURE 1: Process for Developing or Modifying a Reliability Standard

4.1: Posting and Collecting Information on SARs

Standard Authorization Request

A Standard Authorization Request ("SAR") is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified Reliability Standards or definitions or the benefit of retiring one or more approved Reliability Standards. Any entity or individual, including NERC committees or subgroups and NERC Staff, may propose the development of a new or modified Reliability Standard, or may propose the retirement of a Reliability Standard (in whole or in part), by submitting a completed SAR[15] to the NERC Reliability Standards Staff. The Standards Committee has the authority to approve the posting of all SARs for projects that propose (i) developing a new or modified Reliability Standard or definition or (ii) propose retirement of an existing Reliability Standard (or elements thereof).

The NERC Reliability Standards Staff sponsors an open solicitation period each year seeking ideas for new Reliability Standards projects (using *Reliability Standards Suggestions and Comments forms*). The open solicitation period is held in conjunction with the annual revision to the *Reliability Standards Development Plan*. While the Standards Committee prefers that ideas for new projects be submitted during this annual solicitation period through submittal of a *Reliability Standards Suggestions and Comments Form*,[16] a SAR proposing a specific project may be submitted to the NERC Reliability Standards Staff at any time.

Each SAR that proposes a "new" or substantially revised Reliability Standard or definition should be accompanied by a technical justification that includes, as a minimum, a discussion of the reliability-related benefits and costs of developing the new Reliability Standard or definition, and a technical foundation document (*e.g.*, research paper) to guide the development of the Reliability Standard or definition. The technical document should address the engineering, planning and operational basis for the proposed Reliability Standard or definition, as well as any alternative approaches considered during SAR development.

The NERC Reliability Standards Staff shall review each SAR and work with the submitter to verify that all required information has been provided. All properly completed SARs shall be submitted to the Standards Committee for action at the next regularly scheduled Standards Committee meeting.

When presented with a SAR, the Standards Committee shall determine if the SAR is sufficiently complete to guide Reliability Standard development and whether the SAR is consistent with this manual. The Standards Committee shall take one of the following actions:

- Accept the SAR.
- Remand the SAR back to the requestor or to NERC Reliability Standards Staff for additional work.
- Reject the SAR. The Standards Committee may reject a SAR for good cause. If the Standards Committee rejects a SAR, it shall provide a written explanation for rejection to the sponsor within ten days of the rejection decision.
- Delay action on the SAR pending one of the following: (i) development of a technical justification for the proposed project; or (ii) consultation with another NERC Committee to determine if there is another approach to addressing the issue raised in the SAR.

If the Standards Committee is presented with a SAR that proposes developing a new Reliability Standard or definition but does not have a technical justification upon which the Reliability Standard or definition can be developed, the Standards Committee shall direct the NERC Reliability Standards Staff to post the

[15] The SAR form can be downloaded from the Reliability Standards Resources web page.
[16] The *Reliability Standards Suggestions and Comments Form* can be downloaded from the Reliability Standards Resources web page.

SAR for a 30-day comment period solely to collect stakeholder feedback on the scope of technical foundation, if any, needed to support the proposed project. If a technical foundation is determined to be necessary, the Standards Committee shall solicit assistance from NERC's technical committees or other industry experts to provide that foundation before authorizing development of the associated Reliability Standard or definition.

During the SAR comment process, the drafting team may become aware of potential regional Variances related to the proposed Reliability Standard. To the extent possible, any regional Variances or exceptions should be made a part of the SAR so that if the SAR is authorized, such variations shall be made a part of the draft new or revised Reliability Standard.

If the Standards Committee accepts a SAR, the project shall be added to the list of approved projects. The Standards Committee shall assign a priority to the project, relative to all other projects under development, and those projects already identified in the *Reliability Standards Development Plan* that are already approved for development.

The Standards Committee shall work with the NERC Reliability Standards Staff to coordinate the posting of SARs for new projects, giving consideration to each project's priority.

4.2: SAR Posting

When the Standards Committee determines it is ready to initiate a new project, the Standards Committee shall direct NERC Staff to post the project's SAR in accordance with the following:

- For SARs that are limited to addressing regulatory directives, or revisions to Reliability Standards that have had some vetting in the industry, authorize posting the SAR for a 30-day informal comment period with no requirement to provide a formal response to the comments received.
- For SARs that address the development of new projects or Reliability Standards, authorize posting the SAR for a 30-day formal comment period.

If a SAR for a new Reliability Standard is posted for a formal comment period, the Standards Committee shall appoint a drafting team to work with the NERC Staff coordinator to give prompt consideration of the written views and objections of all participants. The Standards Committee may use a public nomination process to populate the Reliability Standard drafting team, or may use another method that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. In some situations, an *ad hoc* team may already be in place with the requisite expertise, competencies, and diversity of views that are necessary to refine the SAR and develop the Reliability Standard, and additional members may not be needed. The drafting team shall address all comments submitted, which may be in the form of a summary response addressing each of the issues raised in comments received, during the public posting period. An effort to resolve all expressed objections shall be made, and each objector shall be advised of the disposition of the objection and the reasons therefore. If the drafting team concludes that there is not sufficient stakeholder support to continue to refine the SAR, the team may recommend that the Standards Committee direct curtailment of work on the SAR.

While there is no established limit on the number of times a SAR may be posted for comment, the Standards Committee retains the right to reverse its prior decision and reject a SAR if it believes continued revisions are not productive. The Standards Committee shall notify the sponsor in writing of the rejection within 10 calendar days.

If stakeholders indicate support for the project proposed with the SAR, the drafting team shall present its work to the Standards Committee with a request that the Standards Committee authorize development of the associated Reliability Standard.

The Standards Committee, once again considering the public comments received and their resolution, may then take one of the following actions:

- Authorize drafting the proposed Reliability Standard or revisions to a Reliability Standard.
- Reject the SAR with a written explanation to the sponsor and post that explanation.

4.3: Form Drafting Team

When the Standards Committee is ready to have a drafting team begin work on developing a new or revised Reliability Standard, the Standards Committee shall appoint a drafting team, if one was not already appointed to develop the SAR. If the Standards Committee appointed a drafting team to refine the SAR, the same drafting team shall work to develop the associated Reliability Standard.

If no drafting team is in place, then the Standards Committee may use a public nomination process to populate the Reliability Standard drafting team, or may use another method that results in a team that collectively has the necessary technical expertise, diversity of views and work process skills to accomplish the objectives of the project on a timely basis. In some situations, an ad hoc team may already be in place with the requisite expertise, competencies, and diversity of views that are necessary to develop the Reliability Standard, and additional members may not be needed.

The NERC Reliability Standards Staff shall provide one or more members as needed to support the team with facilitation, project management, compliance, legal, regulatory and technical writing expertise and shall provide administrative support to the team, guiding the team through the steps in completing its project. In developing the Reliability Standard, the individuals provided by the NERC Reliability Standards Staff serve as advisors to the drafting team and do not have voting rights but share accountability along with the drafting team members assigned by the Standards Committee for timely delivery of a final draft Reliability Standard that meets the quality attributes identified in NERC's Benchmarks for Excellent Standards. The drafting team members assigned by the Standards Committee shall have final authority over the technical details of the Reliability Standard, while the technical writer shall provide assistance to the drafting team in assuring that the final draft of the Reliability Standard meets the quality attributes identified in NERC's Benchmarks for Excellent Standards.

Once it is appointed by the Standards Committee, the Reliability Standard drafting team is responsible for making recommendations to the Standards Committee regarding the remaining steps in the Reliability Standards process. Consistent with the need to provide for timely standards development, the Standards Committee may decide a project is so large that it should be subdivided and either assigned to more than one drafting team or assigned to a single drafting team with clear direction on completing the project in specified phases. The normally expected timeframes for standards development within the context of this manual are applicable to individual standards and not to projects containing multiple standards. Alternatively, a single drafting team may address the entire project with a commensurate increase in the expected duration of the development work. If a SAR is subdivided and assigned to more than one drafting team, each drafting team will have a clearly defined portion of the work such that there are no overlaps and no gaps in the work to be accomplished.

The Standards Committee may supplement the membership of a Reliability Standard drafting team or provide for additional advisors, as appropriate, to ensure the necessary competencies and diversity of views are maintained throughout the Reliability Standard development effort.

4.4: Develop Preliminary Draft of Reliability Standard, Implementation Plan and VRFs and VSLs

4.4.1: Project Schedule

When a drafting team begins its work, either in refining a SAR or in developing or revising a proposed Reliability Standard, the drafting team shall develop a project schedule which shall be approved by the Standards Committee. The drafting team shall report progress to the Standards Committee, against the initial project schedule and any revised schedule as requested by the Standards Committee. Where project milestones cannot be completed on a timely basis, modifications to the project schedule must be presented to the Standards Committee for consideration along with proposed steps to minimize unplanned project delays.

4.4.2: Draft Reliability Standard

The team shall develop a Reliability Standard that is within the scope of the associated SAR that includes all required elements as described earlier in this manual with a goal of meeting the quality attributes identified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval. The team shall document its justification for the Requirements in its proposed Reliability Standard by explaining how each meets these criteria. The standard drafting team shall document its justification for selecting each reference by explaining how each Requirement fits the category chosen.

4.4.3: Implementation Plan

As a drafting team drafts its proposed revisions to a Reliability Standard, that team is also required to develop an implementation plan to identify any factors for consideration when approving the proposed effective date or dates for the associated Reliability Standard or Standards. As a minimum, the implementation plan shall include the following:

- The proposed effective date (the date entities shall be compliant) for the Requirements.
- Identification of any new or modified definitions that are proposed for approval with the associated Reliability Standard.
- Whether there are any prerequisite actions that need to be accomplished before entities are held responsible for compliance with one or more of the Requirements.
- Whether approval of the proposed Reliability Standard will necessitate any conforming changes to any already approved Reliability Standards – and identification of those Reliability Standards and Requirements.
- The Functional Entities that will be required to comply with one or more Requirements in the proposed Reliability Standard.

A single implementation plan may be used for more than one Reliability Standard. The implementation plan is posted with the associated Reliability Standard or Standards during the 45 (calendar) day formal comment period and is balloted with the associated Reliability Standard.

4.4.4: Violation Risk Factors and Violation Severity Levels

The drafting team shall work with NERC Staff in developing a set of VRFs and VSLs that meet the latest criteria established by NERC and Applicable Governmental Authorities. The drafting team shall document its justification for selecting each VRF and for setting each set of proposed VSLs by explaining how its proposed VRFs and VSLs meet these criteria. NERC Staff is responsible for ensuring that the VRFs and VSLs proposed for stakeholder review meet these criteria.

Before the drafting team has finalized its Reliability Standard, implementation plan, and VRFs and VSLs, the team should seek stakeholder feedback on its preliminary draft documents.

4.5: Informal Feedback[17]

Drafting teams may use a variety of methods to collect informal stakeholder feedback on preliminary drafts of its documents, including the use of informal comment periods,[18] webinars, industry meetings, workshops, or other mechanisms. Information gathered from informal comment forms shall be publicly posted. While drafting teams are not required to provide a written response to each individual comment received, drafting teams are encouraged, where possible, to post a summary response that identifies how it used comments submitted by stakeholders. Drafting teams are encouraged, where possible, to reach out directly to individual stakeholders in order to facilitate resolution of identified stakeholder concerns. The intent is to gather stakeholder feedback on a "working document" before the document reaches the point where it is considered the "final draft."

4.6: Conduct Quality Review

The NERC Reliability Standards Staff shall coordinate a quality review of the Reliability Standard, implementation plan, and VRFs and VSLs in parallel with the development of the Reliability Standard and implementation plan, to assess whether the documents are within the scope of the associated SAR, whether the Reliability Standard is clear and enforceable as written, and whether the Reliability Standard meets the criteria specified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval of Reliability Standards. The drafting team shall consider the results of the quality review, decide upon appropriate changes, and recommend to the Standards Committee whether the documents are ready for formal posting and balloting.

The Standards Committee shall authorize posting the proposed Reliability Standard, and implementation plan for a formal comment period and ballot and the VRFs and VSLs for a non-binding poll as soon as the work flow will accommodate.

If the Standards Committee finds that any of the documents do not meet the specified criteria, the Standards Committee shall remand the documents to the drafting team for additional work.

If the Reliability Standard is outside the scope of the associated SAR, the drafting team shall be directed to either revise the Reliability Standard so that it is within the approved scope, or submit a request to expand the scope of the approved SAR. If the Reliability Standard is not clear and enforceable as written, or if the Reliability Standard does not meet the specified criteria, the Reliability Standard shall be returned to the drafting team by the Standards Committee with specific identification of any Requirement that is deemed to be unclear or unenforceable as written.

4.7: Conduct Formal Comment Period and Ballot

Proposed new or modified Reliability Standards require a formal comment period where the new or modified Reliability Standard, implementation plan and associated VRFs and VSLs or the proposal to retire a Reliability Standard, implementation plan and associated VRFs and VSLs are posted.

The formal comment period shall be at least 45-days long. Formation of the ballot pool and Ballot of the Reliability Standard take place during this formal 45-day comment period. The intent of the formal comment period(s) is to solicit very specific feedback on the final draft of the Reliability Standard, implementation plan and VRFs and VSLs.

[17] While this discussion focuses on collecting stakeholder feedback on proposed Reliability Standards and implementation plans, the same process is used to collect stakeholder feedback on proposed new or modified Interpretations, definitions and Variances.

[18] The term "informal comment period" refers to a comment period conducted outside of the ballot process and where there is no requirement for a drafting team to respond in writing to submitted comments.

Comments in written form may be submitted on a draft Reliability Standard by any interested stakeholder, including NERC Staff, FERC Staff, and other interested governmental authorities. If stakeholders disagree with some aspect of the proposed set of products, comments provided should explain the reasons for such disagreement and, where possible, suggest specific language that would make the product acceptable to the stakeholder.

4.8: Form Ballot Pool

The NERC Reliability Standards Staff shall establish a ballot pool during the first 30 calendar days of the 45-day formal comment period. The NERC Reliability Standards Staff shall post the proposed Reliability Standard, along with its implementation plan, VRFs and VSLs and shall send a notice to every entity in the Registered Ballot Body to provide notice that there is a new or revised Reliability Standard proposed for approval and to solicit participants for the associated ballot pool. All members of the Registered Ballot Body are eligible to join each ballot pool to vote on a new or revised Reliability Standard and its implementation plan and to participate in the non-binding poll of the associated VRFs and VSLs.

Any member of the Registered Ballot Body may join or withdraw from the ballot pool until the ballot window opens. No Registered Ballot Body member may join or withdraw from the ballot pool once the first ballot starts through the point in time where balloting for that Reliability Standard action has ended. The Director of Standards may authorize deviations from this rule for extraordinary circumstances such as the death, retirement, or disability of a ballot pool member that would prevent an entity that had a member in the ballot pool from eligibility to cast a vote during the ballot window. Any approved deviation shall be documented and noted to the Standards Committee.

4.9: Conduct Ballot and Non-binding Poll of VRFs and VSLs[19]

The NERC Reliability Standards Staff shall announce the opening of the Ballot window and the non-binding poll of VRFs and VSLs. The Ballot window and non-binding poll of VRFs and VSLs shall take place during the last 10 calendar days of the 45-day formal comment period and for the Final Ballot shall be no less than 10 calendar days. If the last day of the ballot window falls on a Saturday or Sunday, the period does not end until the next business day.[20]

The ballot and non-binding poll shall be conducted electronically. The voting window shall be for a period of 10 calendar days but shall be extended, if needed, until a quorum is achieved. During a ballot window, NERC shall not sponsor or facilitate public discussion of the Reliability Standard action under ballot.

There is no requirement to conduct a new non-binding poll of the revised VRFs and VSLs if no changes were made to the associated standard, however if the requirements are modified and conforming changes are made to the associated VRFs and VSLs, another non-binding poll of the revised VRFs and VSLs shall be conducted.

[19] While RSAWs are not part of the Reliability Standard, they are developed through collaboration of the SDT and NERC Compliance Staff. A non-binding poll, similar to what is done for VRFs and VSLs may be conducted for the RSAW developed through this process to gauge industry support for the companion RSAW to be provided for informational purposes to the NERC Board of Trustees.

[20] Closing dates may be extended as deemed appropriate by NERC Staff.

4.10: Criteria for Ballot Pool Approval

Ballot pool approval of a Reliability Standard requires:

A quorum, which is established by at least 75% of the members of the ballot pool submitting a response; and

A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast is the sum of affirmative votes and negative votes with comments. This calculation of votes for the purpose of determining consensus excludes (i) abstentions, (ii) non-responses, and (iii) negative votes without comments.

The following process[21] is used to determine if there are sufficient affirmative votes.

- For each Segment with ten or more voters, the following process shall be used: The number of affirmative votes cast shall be divided by the sum of affirmative and negative votes with comments cast to determine the fractional affirmative vote for that Segment. Abstentions, non-responses, and negative votes without comments shall not be counted for the purposes of determining the fractional affirmative vote for a Segment.
- For each Segment with less than ten voters, the vote weight of that Segment shall be proportionally reduced. Each voter within that Segment voting affirmative or negative with comments shall receive a weight of 10% of the Segment vote.
- The sum of the fractional affirmative votes from all Segments divided by the number of Segments voting[22] shall be used to determine if a two-thirds majority has been achieved. (A Segment shall be considered as "voting" if any member of the Segment in the ballot pool casts either an affirmative vote or a negative vote with comments.)
- A Reliability Standard shall be approved if the sum of fractional affirmative votes from all Segments divided by the number of voting Segments is at least two thirds.

4.11: Voting Positions

Each member of the ballot pool may **only** vote one of the following positions on the Ballot and Additional Ballot(s):

- Affirmative;
- Affirmative, with comment;
- Negative with comments;
- Abstain.

Given that there is no formal comment period concurrent with the Final Ballot, each member of the ballot pool may **only** vote one of the following positions on the Final Ballot:

- Affirmative;
- Negative;[23]
- Abstain.

[21] Examples of weighted segment voting calculation are posted on the Reliability Standards Resources web page.

[22] When less than ten entities vote in a Segment, the total weight for that Segment shall be determined as one tenth per entity voting, up to ten.

[23] The Final Ballot is used to confirm consensus achieved during the Formal Comment and Ballot stage. Ballot Pool members voting negative on the Final Ballot will be deemed to have expressed the reason for their negative ballot in their own comments or the comments of others during prior Formal Comment periods.

4.12: Consideration of Comments
If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot.

There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.

4.13: Additional Ballots
A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted.

However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted.

4.14: **Conduct Final Ballot**
When the drafting team has reached a point where it has made a good faith effort at resolving applicable objections and is not making any substantive changes from the previous ballot, the team shall conduct a "Final Ballot." A non-substantive revision is a revision that does not change the scope, applicability, or intent of any Requirement and includes but is not limited to things such as correcting the numbering of a Requirement, correcting the spelling of a word, adding an obviously missing word, or rephrasing a Requirement for improved clarity. Where there is a question as to whether a proposed modification is "substantive," the Standards Committee shall make the final determination.

In the Final Ballot, members of the ballot pool shall again be presented the proposed Reliability Standard along with the reasons for negative votes from the previous ballot, the responses of the drafting team to those concerns, and any resolution of the differences.

All members of the ballot pool shall be permitted to reconsider and change their vote from the prior ballot. Members of the ballot pool who did not respond to the prior ballot shall be permitted to vote in the Final Ballot. In the Final Ballot, votes shall be counted by exception only — members on the Final Ballot may indicate a revision to their original vote; otherwise their vote shall remain the same as in their prior ballot.

4.15: Final Ballot Results
There are no limits to the number of public comment periods and ballots that can be conducted to result in a Reliability Standard or interpretation that is clear and enforceable, and achieves a quorum and sufficient affirmative votes for approval. The Standards Committee has the authority to conclude this process for a particular Reliability Standards action if it becomes obvious that the drafting team cannot develop a Reliability Standard that is within the scope of the associated SAR, is sufficiently clear to be enforceable, and achieves the requisite weighted Segment approval percentage.

The NERC Reliability Standards Staff shall post the final outcome of the ballot process. If the Reliability Standard is rejected, the Standards Committee may decide whether to end all further work on the proposed standard, return the project to informal development, or continue holding ballots to attempt to reach

consensus on the proposed standard. If the Reliability Standard is approved, the Reliability Standard shall be posted and presented to the Board of Trustees by NERC management for adoption and subsequently filed with Applicable Governmental Authorities for approval.

4.16: Board of Trustees Adoption of Reliability Standards, Implementation Plan and VRFs and VSLs

If a Reliability Standard and its associated implementation plan are approved by its ballot pool, the Board of Trustees shall consider adoption of that Reliability Standard and its associated implementation plan and shall direct the standard to be filed with Applicable Governmental Authorities for approval. In making its decision, the Board shall consider the results of the balloting and unresolved dissenting opinions. The Board shall adopt or reject a Reliability Standard and its implementation plan, but shall not modify a proposed Reliability Standard. If the Board chooses not to adopt a Reliability Standard, it shall provide its reasons for not doing so.

The board shall consider approval of the VRFs and VSLs associated with a reliability standard. In making its determination, the board shall consider the following:

- The Standards Committee shall present the results of the non-binding poll conducted and a summary of industry comments received on the final posting of the proposed VRFs and VSLs.
- NERC Staff shall present a set of recommended VRFs and VSLs that considers the views of the standard drafting team, stakeholder comments received on the draft VRFs and VSLs during the posting for comment process, the non-binding poll results, appropriate governmental agency rules and directives, and VRF and VSL assignments for other Reliability Standards to ensure consistency and relevance across the entire spectrum of Reliability Standards.

4.17: Compliance

For a Reliability Standard to be enforceable, it shall be approved by its ballot pool, adopted by the NERC Board of Trustees, and approved by Applicable Governmental Authorities, unless otherwise approved by the NERC Board of Trustees pursuant to the NERC Rules of Procedure (*e.g*, Section 321) and approved by Applicable Governmental Authorities. Once a Reliability Standard is approved or otherwise made mandatory by Applicable Governmental Authorities, all persons and organizations subject to jurisdiction of the ERO will be required to comply with the Reliability Standard in accordance with applicable statutes, regulations, and agreements.

4.18: Withdrawal of a Reliability Standard, Interpretation, or Definition

The term "withdrawal" as used herein, refers to the discontinuation of a Reliability Standard, Interpretation, Variance or definition that has been approved by the Board of Trustees and (1) has not been filed with Applicable Governmental Authorities, or (2) has been filed with, but not yet approved by, Applicable Governmental Authorities. The Standards Committee may withdraw a Reliability Standard, Interpretation or definition for good cause upon approval by the Board of Trustees. Upon approval by the Board of Trustees, NERC Staff will petition the Applicable Governmental Authorities, as needed, to allow for withdrawal. The Board of Trustees also has an independent right of withdrawal that is unaffected by the terms and conditions of this Section.

4.19: Retirement of a Reliability Standard, Interpretation, or Definition

The term "retirement" refers to the discontinuation of a Reliability Standard, Interpretation or definition that has been approved by Applicable Governmental Authorities. A Reliability Standard, Variance or Definition may be retired when it is superseded by a revised version, and in such cases the retirement of the

earlier version is to be noted in the implementation plan presented to the ballot pool for approval and the retirement shall be considered approved by the ballot pool upon ballot pool approval of the revised version.

Upon identification of a need to retire a Reliability Standard, Variance, Interpretation or definition, where the item will not be superseded by a new or revised version, a SAR containing the proposal to retire a Reliability Standard, Variance, Interpretation or definition will be posted for a comment period and ballot in the same manner as a Reliability Standard. The proposal shall include the rationale for the retirement and a statement regarding the impact of retirement on the reliability of the Bulk Power System. Upon approval by the Board of Trustees, NERC Staff will petition the Applicable Governmental Authorities to allow for retirement.

Section 5.0: Process for Developing a Defined Term

NERC maintains a glossary of approved terms, entitled the *Glossary of Terms Used in NERC Reliability Standards*[24] ("Glossary of Terms"). The Glossary of Terms includes terms that have been through the formal approval process and are used in one or more NERC Reliability Standards. Definitions shall not contain statements of performance Requirements. The Glossary of Terms is intended to provide consistency throughout the Reliability Standards.

There are several methods that can be used to add, modify or retire a defined term used in a continent-wide Reliability Standard.

- Anyone can use a Standard Authorization Request ("SAR") to submit a request to add, modify, or retire a defined term.
- Anyone can submit a Standards Comments and Suggestions Form recommending the addition, modification, or retirement of a defined term. (The suggestion would be added to a project and incorporated into a SAR.)
- A drafting team may propose to add, modify, or retire a defined term in conjunction with the work it is already performing.

5.1: Proposals to Develop a New or Revised Definition

The following considerations should be made when considering proposals for new or revised definitions:

- Some NERC Regional Entities have defined terms that have been approved for use in Regional Reliability Standards, and where the drafting team agrees with a term already defined by a Regional Entity, the same definition should be adopted if needed to support a NERC Reliability Standard.
- If a term is used in a Reliability Standard according to its common meaning (as found in a collegiate dictionary), the term shall not be proposed for addition to the Glossary of Terms.
- If a term has already been defined, any proposal to modify or delete that term shall consider all uses of the definition in approved Reliability Standards, with a goal of determining whether the proposed modification is acceptable, and whether the proposed modification would change the scope or intent of any approved Reliability Standards.
- When practical, where NAESB has a definition for a term, the drafting team shall use the same definition to support a NERC Reliability Standard.

Any definition that is balloted separately from a proposed new or modified Reliability Standard or from a proposal for retirement of a Reliability Standard shall be accompanied by an implementation plan.

If a SAR is submitted to the NERC Reliability Standards Staff with a proposal for a new or revised definition, the Standards Committee shall consider the urgency of developing the new or revised definition and may direct NERC Staff to post the SAR immediately, or may defer posting the SAR until a later time based on its priority relative to other projects already underway or already approved for future development. If the SAR identifies a term that is used in a Reliability Standard already under revision by a drafting team, the Standards Committee may direct the drafting team to add the term to the scope of the existing project. Each time the Standards Committee accepts a SAR for a project that was not identified in the *Reliability Standards Development Plan*, the project shall be added to the list of approved projects.

[24] The latest approved version of the Glossary of Terms is posted on the NERC website on the Standards web page.

5.2: Stakeholder Comments and Approvals

Any proposal for a new or revised definition shall be processed in the same manner as a Reliability Standard and quality review shall be conducted in parallel with this process. Once authorized by the Standards Committee, the proposed definition and its implementation plan shall be posted for at least one formal stakeholder comment period and shall be balloted in the same manner as a Reliability Standard. If a new or revised definition is proposed by a drafting team, that definition may be balloted separately from the associated Reliability Standard.

Each definition that is approved by its ballot pool shall be submitted to the NERC Board of Trustees for adoption and then filed with Applicable Governmental Authorities for approval in the same manner as a Reliability Standard.

Section 6.0: Processes for Conducting Field Tests and Collecting and Analyzing Data

While most drafting teams can develop their Reliability Standards without the need to conduct any field tests and without the need to collect and analyze data, some Reliability Standard development efforts may require benefit from field tests to analyze data and validate concepts in the development of Reliability Standards. Drafting teams are not required to collect and analyze data or to conduct a field test to validate a Reliability Standard.

There are two types of field tests – tests of concepts and tests of requirements. A field test is initiated by either a SAR or Reliability Standard drafting team. The drafting team may be supplemented with other individuals based on the required technical expertise needed to support the field test. The drafting team is responsible for developing the field test plan, including the implementation schedule, and for identifying compliance related issues such as the potential need for compliance waivers.

6.1: Field Tests and Data Analysis for Validation of Concepts (collectively "field test")

- Field tests or collection and analysis of data to validate concepts that support the development of Requirements Reliability Standards should be conducted, to the extent possible, before the SAR for a project is finalized. If an entity wants to test a technical concept in support of a proposal for a new or revised Reliability Standard, the entity should either work with one of NERC's technical committees in collecting and analyzing the data or in conducting the field test, or the entity should submit a SAR with a request to collect and analyze data or conduct a field test to validate the concept prior to developing a new or revised Reliability Standard. The request to collect and analyze data or conduct a field test should include, at a minimum, either the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the analysis of the results. If the SAR sponsor has not collected and analyzed the data or conducted the field test, the Standards Committee may solicit support from NERC's technical committees or others in the industry. The results of the data collection and analysis or field test shall then be used to determine whether to add the SAR to the list of projects in the Reliability Standard Development Plan.
- To conduct a field test of a technical concept in a proposed new or revised Reliability Standard, the drafting team must work with NERC Staff to identify one of NERC's technical committees to oversee the field test as well as other technical committees with relevant technical expertise.
- The field test is conducted by the drafting team, in coordination with NERC Staff and under the oversight of the assigned technical committee, in accordance with an approved field test plan.

If a drafting team finds that it needs to collect and analyze data or conduct a field test of a concept that was not identified when the SAR was accepted, then the Standards Committee may direct the team to withdraw the SAR until the data has been collected and analyzed or until the field test has been conducted and the industry has had an opportunity to review the results for the impact on the scope of the proposed project.

6.1.1. Field Test Approval

The request to conduct a field test shall include, at a minimum:

- the field test plan,
- the implementation schedule, and
- an expectation for periodic updates of the analysis of the results to the lead NERC technical committee.

Prior to the drafting team conducting a field test, the drafting team must first receive approval from the lead NERC technical committee. Second, the drafting team must receive approval from the Standards Committee.

The lead NERC technical committee's approval shall be based on the technical adequacy of the field test plan. Following approval, the lead NERC technical committee shall provide a recommendation to the Standards Committee for the disposition of the field test plan request. The lead NERC technical committee shall coordinate all entity participation in the field test, such as accepting, adding, and withdrawing individual entities from the field test, as well as coordinating and communicating status of the results of the field test.

The Standards Committee's decision to approve the field test plan request shall be based solely on whether the Standards Committee, by majority vote, agrees or disagrees with the lead NERC technical committee's recommendation. If the Standards Committee disagrees with the lead NERC technical committee's recommendation, the Standards Committee shall inform the lead NERC technical committee with an explanation of the basis for the decision.

6.1.2: Field Test Suspension for Reliability Concerns

During the field test, if the lead NERC technical committee overseeing the field test determines that the field test is creating a reliability risk to the Bulk Power System:

- the lead NERC technical committee shall stop or modify the activity;
- the lead NERC technical committee shall inform the Standards Committee that the activity was stopped or modified;
- the Standards Committee, with the assistance of NERC Staff, shall document the cessation or modification of the field test; and
- the Standards Committee, with the assistance of NERC Staff, shall notify NERC Compliance Monitoring and Enforcement Program Staff to coordinate any compliance related issues such as continuance or cessation of waivers (see Section 6.2).

Prior to the field test being restarted after it has been stopped, the drafting team must resubmit the field test request and receive approval as outlined in Section 6.1.1.

6.1.3: Continuing, Modifying, or Terminating a Field Test

If the drafting team concludes that a field test does not provide sufficient information to formulate a conclusion within the time allotted in the plan, the drafting team shall provide a recommendation to either continue (including extending the duration of the field test beyond the period of standard development), modify, or terminate the field test to the lead NERC technical committee and the chair of the Standards Committee. The lead NERC technical committee shall either approve or reject a request to continue, modify, or terminate the field test, and thereafter, provide notice to the chair of the Standards Committee of its selection.

If the duration of the field test is extended beyond the period of standard development, the preliminary report and results shall be publicly posted on the NERC web site prior to the final ballot of the Reliability Standard.

~~**6.2: Field Tests and Data Analysis for Validation of Requirements**~~

~~If a drafting team wants to conduct a field test or collect and analyze data to validate its proposed Requirements in a Reliability Standard, the team shall first obtain approval from the Standards~~

Committee.[25] Drafting teams are not required to collect and analyze data or to conduct a field test to validate a Reliability Standard.

The request should include at a minimum the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the results. When authorizing a drafting team to collect and analyze data or to conduct a field test of one or more Requirements, the Standards Committee may request inputs on technical matters related from NERC's technical committees or industry experts, and may request the assistance of the Compliance Monitoring and Enforcement Program. All data collection and analysis and all field tests shall be concluded and the results incorporated into the Reliability Standard Requirements as necessary before proceeding to the formal comment period and subsequent balloting.

6.32: Communication and Coordination for All Types of Field Tests and Data Analyses

If the conduct of a field test (concepts or Requirements) or data collection and analysis could After approval of the field test, the drafting team may request waivers of compliance for field test participants that would be rendered Registered Entities incapable of complying with the current Requirement(s) of an approveda currently enforceable Reliability Standard that is undergoing revision, the drafting team shall request a temporary waiver from compliance to those Requirements for entities participating in the field test due to their participation. Upon request, the Standards Committee shall seek approval for the waiver from the The NERC Compliance Monitoring and Enforcement Program Staff prior to the approval of the field test or data collection and analysisshall determine whether to approve the requested waivers and shall be responsible for approving any modifications or terminations that may become necessary following the start of the field test. The NERC Reliability Standards Staff shall inform the affected Registered Entities. Prior to initiation of the field test, the chair of the Standards Committee, in conjunction with the lead NERC technical committee chair, shall inform the Board of Trustees of the pending field test, the expected duration, and any requested waivers of compliance for Registered Entities.

During the field test, the drafting team shall provide periodic updates (no less than quarterly) on the progress of the field test to the Standards Committee and the NERC technical committees. Prior to the ballot of any standard involving a field test, the drafting team shall provide to the Standards Committee either a preliminary report of the results of the field test to date, if the field test will continue beyond standard development, or a final report if the field test has been completed. The chair of the Standards Committee shall keep the Board of Trustees informed.

Once a plan for a field test or a plan for data collection and analysis is approved, the NERC Reliability Standards Staff shall, under the direction of the Standards Committee, coordinate the implementation of the field test or data collection and analysis and shall provide official notice to the participants in the field test or data collection of any applicable temporary waiver to compliance with specific noted Requirements. The drafting team conducting the field test shall provide periodic updates on the progress of the field tests or data collection and analysis to the Standards Committee. The Standards Committee has the right to curtail a field test or data collection and analysis that is not implemented in accordance with the approved plan.

The field test plan or data collection and analysis plan, its approval, its participants, and all reports and results shall be publicly posted for stakeholder review on the NERC Reliability Standards web pagesite. This posting shall include the participant list, unless it is determined that posting this list would present confidentiality or other concerns.

[25] The Process for Approving Data Collection and Analysis and Field Tests Associated with a Reliability Standard is posted on the Reliability Standards Resources web page.

If a drafting team conducts or participates in a field test or in data collection and analysis (of concepts or Requirements), it shall provide a final report that identifies the results and how those results will be used.

Section 7.0: Process for Developing an Interpretation

A valid Interpretation request is one that requests additional clarity about one or more Requirements in approved NERC Reliability Standards, but does not request approval as to how to comply with one or more Requirements. A valid Interpretation response provides additional clarity about one or more Requirements, but does not expand on any Requirement and does not explain how to comply with any Requirement. Any entity that is directly and materially affected by the reliability of the North American Bulk Power Systems may request an Interpretation of any Requirement in any continent-wide Reliability Standard that has been adopted by the NERC Board of Trustees. Interpretations will only be provided for Board of Trustees-approved Reliability Standards *i.e.* (i) the current effective version of a Reliability Standard; or (ii) a version of a Reliability Standard with a future effective date.

7.1: Valid Interpretation

An Interpretation may only clarify ~~or interpret~~ the language of the Requirement(s) of an approved Reliability Standard, including, if applicable, any attachment referenced in the Requirement ~~being clarified~~. The Interpretation may not alter the scope or the language of a Requirement or referenced attachment. No other elements of an approved Reliability Standard are subject to an Interpretation.

7.2: Process for Requesting an Interpretation

The entity requesting the Interpretation shall submit a *Request for Interpretation* form[26] to the NERC Reliability Standards Staff explaining the clarification required, the specific circumstances surrounding the request, and the impact of not having the Interpretation provided. ~~The~~ NERC Reliability Standards and Legal Staff~~s~~ shall review the request for ~~interpretation~~ Interpretation to determine whether it meets the requirements for a valid ~~interpretation~~Interpretation. Based on this review, ~~the~~ NERC ~~Standards and Legal~~ Staff~~s~~ shall make a recommendation to the Standards Committee whether to accept the request for Interpretation and move forward in responding to the Interpretation request.

7.2.1: Rejection of an Interpretation Request

~~For example, an~~A request for Interpretation ~~request~~ may be rejected ~~where it~~in the following circumstances:

- ~~(1)~~ Where the r~~R~~equest~~s~~ seeks approval of a particular compliance approach.[27] ~~;~~
- ~~(2) Identifies a gap or perceived weakness in the approved Reliability Standard;~~
- ~~(3)~~ Where ~~an~~ the issue can be addressed by incorporating the issue into an ~~active~~ existing or future standard ~~drafting team~~development project.~~;~~
- ~~(4)~~ Where ~~it~~ the request~~s~~ seeks clarification of any element of a Reliability Standard other than a Requirement.~~;~~
- ~~(5)~~ Where ~~a question~~the issue has already been addressed in the record.~~;~~
- ~~(6)~~ Where the ~~Interpretation~~ request identifies an issue and proposes the development of a new or modified Reliability Standard~~,~~ (such issues should be addressed via submission of a SAR).~~;~~
- ~~(7)~~ Where ~~an Interpretation~~the request seeks to expand the scope of a Reliability Standard.~~; or~~
- ~~(8)~~ Where the meaning of a Reliability Standard is plain on its face.

[26] The *Request for Interpretation* form is posted on the NERC Standards web page.

[27] Requests that contain specific compliance approaches, or examples of compliance, are not candidates for Interpretations and should be pursued through the applicable NERC Compliance Monitoring and Enforcement Program processes.

If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for the ~~rejecting the Interpretation~~rejection to the entity requesting the Interpretation within 10 business days of the decision to reject.

7.2.2: Acceptance of an Interpretation Request

If the Standards Committee accepts the Interpretation request, the Standards Committee shall authorize NERC Reliability Standards Staff ~~shall (i) form a ballot pool and (ii)~~to assemble an Interpretation drafting team with the relevant expertise to address the request~~interpretation for approval by the Standards Committee~~.

7.3: Development of an Interpretation

As soon as practical, the Interpretation drafting team shall develop a ~~"final~~ draft~~"~~ Interpretation ~~providing the requested clarity~~addressing the request, consistent with Section 7.1. Interpretations shall be developed in accordance with the following process:

- NERC Reliability Standards staff shall review the draft Interpretation to determine whether it has met the requirements for a valid Interpretation and to provide a recommendation to the Standards Committee whether to authorize posting or remand to the Interpretation drafting team for further work.
- The Standards Committee, after review of the Staff recommendation, may authorize posting of the draft Interpretation for comment and ballot.
- Interpretations ~~will~~ shall be balloted in the same manner as Reliability Standards (*see* Section 4.0), with the following exceptions:
  - Interpretations shall be posted for a 30-day informal comment period. The Interpretation drafting team is not required to respond in writing to comments submitted during this comment period.
  - The NERC Reliability Standards Staff shall establish a ballot pool during the first 20 days of the 30-day informal comment period.
  - The ballot window shall take place during the last 10 calendar days of the 30-day informal comment period.
  - Final Ballots shall not be conducted for Interpretations. An Interpretation shall be deemed approved by the ballot pool following the first ballot in which the necessary quorum and sufficient affirmative votes are obtained.

If ~~stakeholder comments~~the ballot results indicate that there is not a consensus for the Interpretation, and the Interpretation drafting team cannot revise the Interpretation without violating the basic ~~expectations~~ criteria ~~outlined above~~for what constitutes a valid Interpretation (see Section 7.1), the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with the proposed modification to the Reliability Standard. The entity that requested the Interpretation shall be notified in writing and the disposition of the Interpretation shall be posted.

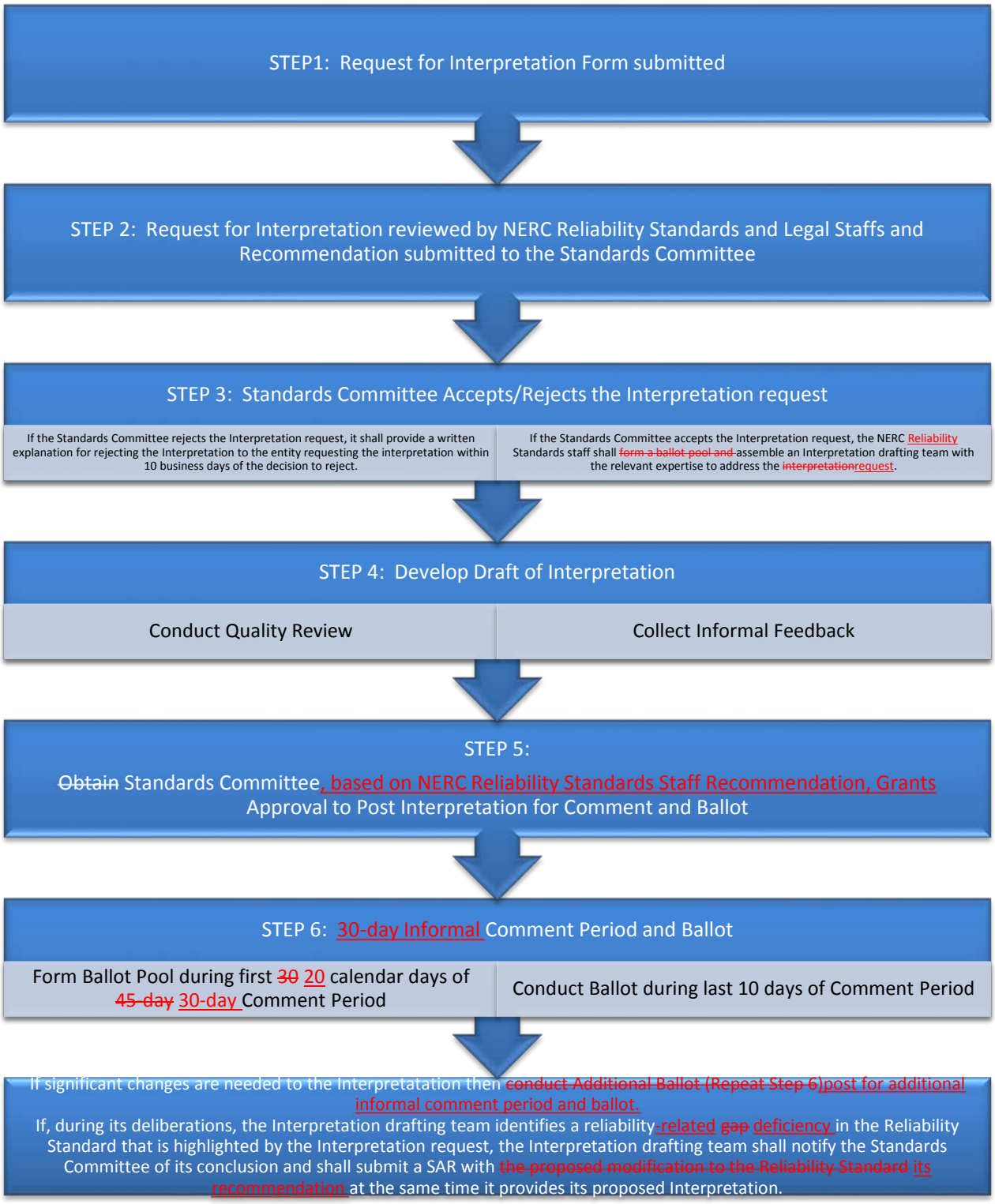
If, during its deliberations, the Interpretation drafting team identifies a reliability-related ~~gap~~ deficiency in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with ~~the proposed modification to the Reliability Standard~~its recommendation at the same time it provides its proposed Interpretation.

If approved by the ballot pool, ~~The~~ NERC ~~Reliability Standards and Legal~~ Staff~~s~~ shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation and ~~. Based on this review, the NERC Standards and Legal Staffs~~ shall make a recommendation to the NERC Board of Trustees regarding adoption.

~~If approved by its ballot pool, the Interpretation shall be forwarded to the NERC Board of Trustees for adoption.[28]~~ If an Interpretation drafting team ~~proposes~~ recommends a modification to a Reliability Standard as part of its work in developing an Interpretation, the Board of Trustees shall be notified of this ~~proposal~~ recommendation at the time the Interpretation is submitted for adoption. Following ~~adoption by the~~ Board of Trustees adoption, ~~NERC Staff shall file~~ the Interpretation shall be filed ~~for approval by~~with the Applicable Governmental Authorities, and the Interpretation shall become effective when approved by those Applicable Governmental Authorities.[29] The Interpretation shall stand until ~~such time as~~ the Interpretation can be incorporated into a future revision of the Reliability Standard or the Interpretation is retired due to a future modification of the applicable Requirement.

~~[28] NERC will maintain a record of all interpretations associated with each standard on the Reliability Standards page of the NERC website.~~

[29] NERC will maintain a record of all interpretations associated with each standard on the Reliability Standards page of the NERC website.


STEP1: Request for Interpretation Form submitted
STEP 2: Request for Interpretation reviewed by NERC Reliability Standards and Legal Staffs and Recommendation submitted to the Standards Committee
STEP 3: Standards Committee Accepts/Rejects the Interpretation request
If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the Interpretation to the entity requesting the interpretation within 10 business days of the decision to reject.
If the Standards Committee accepts the Interpretation request, the NERC Reliability Standards staff shall form a ballot pool and assemble an Interpretation drafting team with the relevant expertise to address the interpretationrequest.
STEP 4: Develop Draft of Interpretation
Conduct Quality Review
Collect Informal Feedback
STEP 5:
Obtain Standards Committee, based on NERC Reliability Standards Staff Recommendation, Grants Approval to Post Interpretation for Comment and Ballot
STEP 6: 30-day Informal Comment Period and Ballot
Form Ballot Pool during first 30 20 calendar days of 45-day 30-day Comment Period
Conduct Ballot during last 10 days of Comment Period
If significant changes are needed to the Interpretatation then conduct Additional Ballot (Repeat Step 6)post for additional informal comment period and ballot.
If, during its deliberations, the Interpretation drafting team identifies a reliability-related gap deficiency in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and shall submit a SAR with the proposed modification to the Reliability Standard its recommendation at the same time it provides its proposed Interpretation.

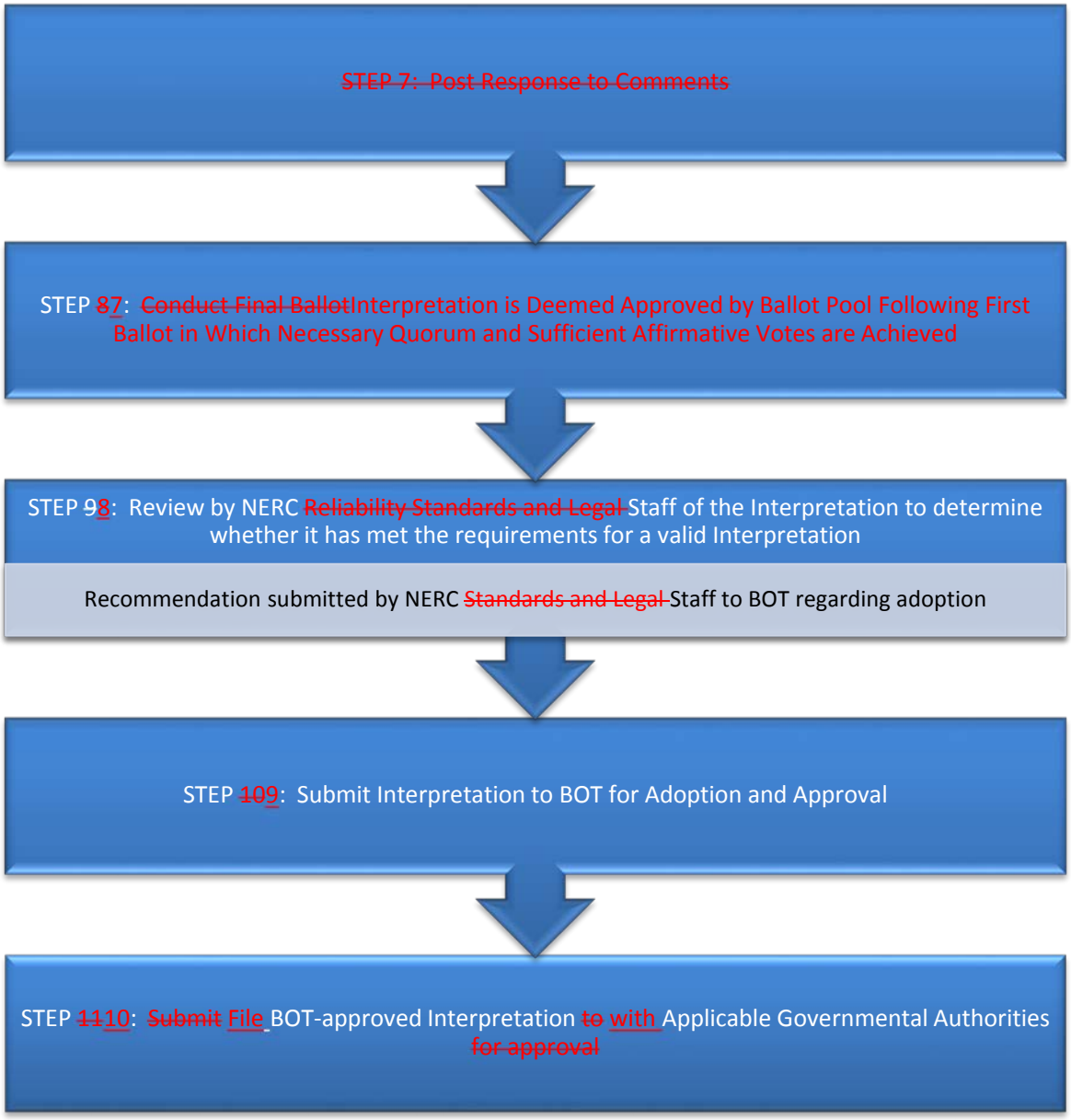


FIGURE 2: Process for Developing an Interpretation

Section 8.0: Process for Appealing an Action or Inaction

Any entity that has directly and materially affected interests and that has been or will be adversely affected by any procedural action or inaction related to the development, approval, revision, reaffirmation, retirement or withdrawal of a Reliability Standard, definition, Variance, associated implementation plan, or Interpretation shall have the right to appeal. This appeals process applies only to the NERC Reliability Standards processes as defined in this manual, not to the technical content of the Reliability Standards action.

The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made in writing within 30 days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. The final decisions of any appeal shall be documented in writing and made public.

The appeals process provides two levels, with the goal of expeditiously resolving the issue to the satisfaction of the participants.

8.1: Level 1 Appeal

Level 1 is the required first step in the appeals process. The appellant shall submit (to the Director of Standards) a complaint in writing that describes the procedural action or inaction associated with the Reliability Standards process. The appellant shall describe in the complaint the actual or potential adverse impact to the appellant. Assisted by NERC Staff and industry resources as needed, the Director of Standards shall prepare a written response addressed to the appellant as soon as practical but not more than 45 days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response shall be made a part of the public record associated with the Reliability Standard.

At any time prior to receiving the written response to the Level 1 Appeal, an appellant may withdraw the Level 1 Appeal with written notice to the Director of Standards.

8.2: Level 2 Appeal

If after the Level 1 Appeal the appellant remains unsatisfied with the resolution, as indicated by the appellant in writing to the Director of Standards, the Director of Standards shall convene a Level 2 Appeals Panel. This panel shall consist of five members appointed by the Board of Trustees. In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The NERC Reliability Standards Staff shall post the complaint and other relevant materials and provide at least 30 days notice of the meeting of the Level 2 Appeals Panel. In addition to the appellant, any entity that is directly and materially affected by the procedural action or inaction referenced in the complaint shall be heard by the panel. The panel shall not consider any expansion of the scope of the appeal that was not presented in the Level 1 Appeal. The panel may, in its decision, find for the appellant and remand the issue to the Standards Committee with a statement of the issues and facts in regard to which fair and equitable action was not taken. The panel may find against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections. The panel may not, however, revise, approve, disapprove, or adopt a Reliability Standard, definition, Variance or Interpretation or implementation plan as these responsibilities remain with the ballot pool and Board of Trustees respectively. The actions of the Level 2 Appeals Panel shall be publicly posted.

At any time prior to the meeting of the Level 2 Appeals Panel, an appellant may withdraw the Level 2 Appeal and accept the results of the Level 1 Appeal by providing written notice to the Director of Standards.

In addition to the foregoing, a procedural objection that has not been resolved may be submitted to the Board of Trustees for consideration at the time the Board decides whether to adopt a particular Reliability Standard, definition, Variance or Interpretation. The objection shall be in writing, signed by an officer of the objecting entity, and contain a concise statement of the relief requested and a clear demonstration of the facts that justify that relief. The objection shall be filed no later than 30 days after the announcement of the vote by the ballot pool on the Reliability Standard in question.

Section 9.0: Process for Developing a Variance

A Variance is an approved, alternative method of achieving the reliability intent of one or more Requirements in a Reliability Standard. No Regional Entity or Bulk Power System owner, operator, or user shall claim a Variance from a NERC Reliability Standard without approval of such a Variance through the relevant Reliability Standard approval procedure for the Variance. Each Variance from a NERC Reliability Standard that is approved by NERC and Applicable Governmental Authorities shall be made an enforceable part of the associated NERC Reliability Standard.

NERC's drafting teams shall aim to develop Reliability Standards with Requirements that apply on a continent-wide basis, minimizing the need for Variances while still achieving the Reliability Standard's reliability objectives. If one or more Requirements cannot be met or complied with as written because of a physical difference in the Bulk Power System or because of an operational difference (such as a conflict with a federally or provincially approved tariff), but the Requirement's reliability objective can be achieved in a different fashion, an entity or a group of entities may pursue a Variance from one or more Requirements in a continent-wide Reliability Standard. It is the responsibility of the entity that needs a Variance to identify that need and initiate the processing of that Variance through the submittal of a SAR[30] that includes a clear definition of the basis for the Variance.

There are two types of Variances – those that apply on an Interconnection-wide basis, and those that apply to one or more entities on less than an Interconnection-wide basis.

9.1: Interconnection-wide Variances

Any Variance from a NERC Reliability Standard Requirement that is proposed to apply to Registered Entities within a Regional Entity organized on an Interconnection-wide basis shall be considered an Interconnection-wide Variance and shall be developed through that Regional Entity's NERC-approved Regional Reliability Standards development procedure.

While an Interconnection-wide Variance may be developed through the associated Regional Reliability Standards development process, Regional Entities are encouraged to work collaboratively with existing continent-wide drafting teams to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC Reliability Standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC Reliability Standard that is developed, in accordance with a Regional Reliability Standards development procedure approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

9.2: Variances that Apply on Less than an Interconnection-wide Basis

Any Variance from a NERC Reliability Standard Requirement that is proposed to apply to one or more entities but less than an entire Interconnection (*e.g.*, a Variance that would apply to a regional transmission organization or particular market or to a subset of Bulk Power System owners, operators, or users), shall be considered a Variance. A Variance may be requested while a Reliability Standard is under development or a Variance may be requested at any time after a Reliability Standard is approved. Each request for a

[30] A sample of a SAR that identifies the need for a Variance and a sample Variance are posted as resources on the Reliability Standards Resources web page.

Variance shall be initiated through a SAR, and processed and approved in the same manner as a continent-wide Reliability Standard, using the Reliability Standards development process defined in this manual.

Section 10.0: Processes for Developing a Reliability Standard Related to a Confidential Issue

While it is NERC's intent to use its ANSI-accredited Reliability Standards development process for developing its Reliability Standards, NERC has an obligation as the ERO to ensure that there are Reliability Standards in place to preserve the reliability of the interconnected Bulk Power Systems throughout North America. When faced with a national security emergency situation, NERC may use one of the following special processes to develop a Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one of the following processes shall be called, "special Reliability Standards" and shall not be filed with ANSI for approval as American National Standards.

The NERC Board of Trustees may direct the development of a new or revised Reliability Standard to address a national security situation that involves confidential issues. These situations may involve imminent or long-term threats. In general, these Board directives will be driven by information from the President of the United States of America or the Prime Minister of Canada or a national security agency or national intelligence agency of either or both governments indicating (to the ERO) that there is a national security threat to the reliability of the Bulk Power System.[31]

There are two special processes for developing Reliability Standards responsive to confidential issues – one process where the confidential issue is "imminent," and one process where the confidential issue is "not imminent."

10.1: Process for Developing Reliability Standards Responsive to Imminent, Confidential Issues
If the NERC Board of Trustees directs the immediate development of a new or revised Reliability Standard to address a confidential national security emergency situation, the NERC Reliability Standards Staff shall develop a SAR, form a ballot pool (to vote on the Reliability Standard and its implementation plan) and assemble a slate of pre-defined subject matter experts as a proposed drafting team for approval by the Standards Committee's officers. All members of the Registered Ballot Body shall have the opportunity to join the ballot pool.

10.2: Drafting Team Selection
The Reliability Standard drafting team selection process shall be limited to just those candidates who have already been identified as having the appropriate security clearance, the requisite technical expertise, and either have signed or are willing to sign a strict confidentiality agreement.

10.3: Work of Drafting Team
The Reliability Standard drafting team shall perform all its work under strict security and confidential rules. The Reliability Standard drafting team shall develop the new or revised Reliability Standard and its implementation plan.

The Reliability Standard drafting team shall review its work, to the extent practical, as it is being developed with officials from the appropriate governmental agencies in the U.S. and Canada, under strict security and confidentiality rules.

10.4: Formal Stakeholder Comment & Ballot Window

[31] The NERC Board may direct the immediate development and issuance of a Level 3 (Essential Action) alert and then may also direct the immediate development of a new or revised Reliability Standard.

The draft Reliability Standard and its implementation plan shall be distributed for a formal comment period, under strict confidentiality rules, only to those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.[32] At the same time, the Reliability Standard shall be distributed to the members of the ballot pool for review and ballot. The NERC Reliability Standards Staff shall not post or provide the ballot pool with any confidential background information.

The drafting team, working with the NERC Reliability Standards Staff, shall consider and respond to all comments, make any necessary conforming changes to the Reliability Standard and its implementation plan, and shall distribute the comments, responses and any revision to the same population as received the initial set of documents for formal comment and ballot.

10.5: Board of Trustee Actions
Each Reliability Standard and implementation plan developed through this process shall be submitted to the NERC Board of Trustees for adoption.

10.6: Governmental Approvals
All approved documents shall be filed for approval with Applicable Governmental Authorities.

[32] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

10.7: Developing a Reliability Standard Responsive to an Imminent, Confidential Issue

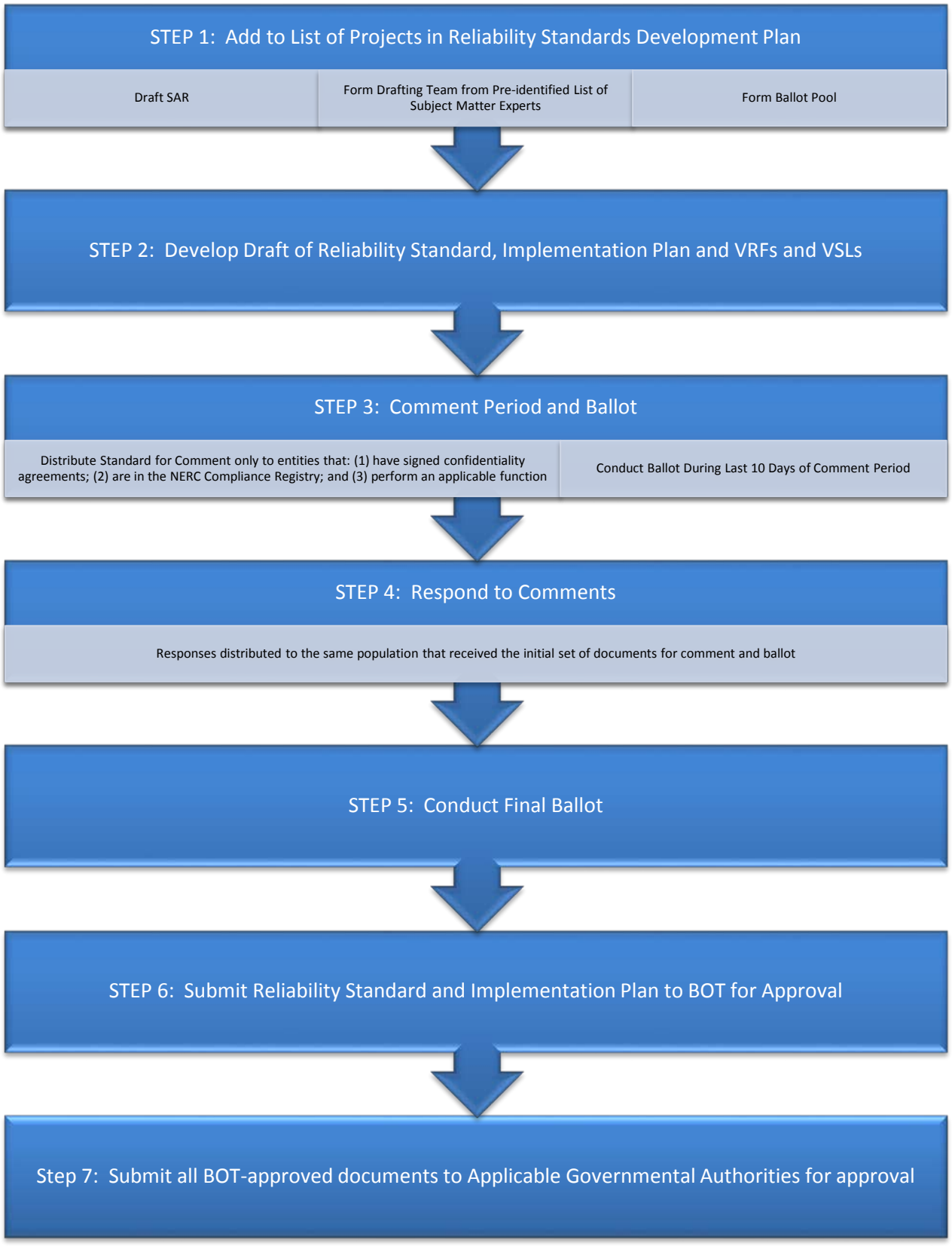


FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

10.8: Process for Developing Reliability Standards Responsive to Non-imminent, Confidential Issues

If the NERC Board of Trustees directs the immediate development of a new or revised Reliability Standard to address a confidential national security emergency situation, the NERC Reliability Standards Staff shall develop a SAR, form a ballot pool (to vote on the Reliability Standard and its implementation plan) and assemble a slate of pre-defined subject matter experts as a proposed drafting team for approval by the Standards Committee's officers. All members of the Registered Ballot Body shall have the opportunity to join the ballot pool.

10.9: Drafting Team Selection

The drafting team selection process shall be limited to just those candidates who have already been identified as having the appropriate security clearance, the requisite technical expertise, and either have signed or are willing to sign a strict confidentiality agreement.

10.10: Work of Drafting Team

The drafting team shall perform all its work under strict security and confidential rules. The Reliability Standard drafting team shall develop the new or revised Reliability Standard and its implementation plan.

The drafting team shall review its work, to the extent practical, as it is being developed with officials from the Applicable Governmental Authorities, under strict security and confidentiality rules.

10.11: Formal Stakeholder Comment & Ballot Window

The draft Reliability Standard and its implementation plan shall be distributed for a formal comment period, under strict confidentiality rules, only to those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.[33] At the same time, the Reliability Standard shall be distributed to the members of the ballot pool for review and ballot. The NERC Reliability Standards Staff shall not post or provide the ballot pool with any confidential background information.

10.12: Revisions to Reliability Standard, Implementation Plan and VRFs and VSLs

The drafting team, working with the NERC Reliability Standards Staff, shall work to refine the Reliability Standard, implementation plan and VRFs and VSLs in the same manner as for a new Reliability Standard following the "normal" Reliability Standards development process described earlier in this manual with the exception that distribution of the comments, responses, and new drafts shall be limited to those entities that are in the ballot pool and those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.

10.13: Board of Trustee Action

Each Reliability Standard, implementation plan, and the associated VRFs and VSLs developed through this process shall be submitted to the NERC Board of Trustees for adoption.

10.14: Governmental Approvals

All BOT-approved documents shall be filed for approval with Applicable Governmental Authorities.

[33] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

Developing a Reliability Standard Responsive to a Non-imminent, Confidential Issue

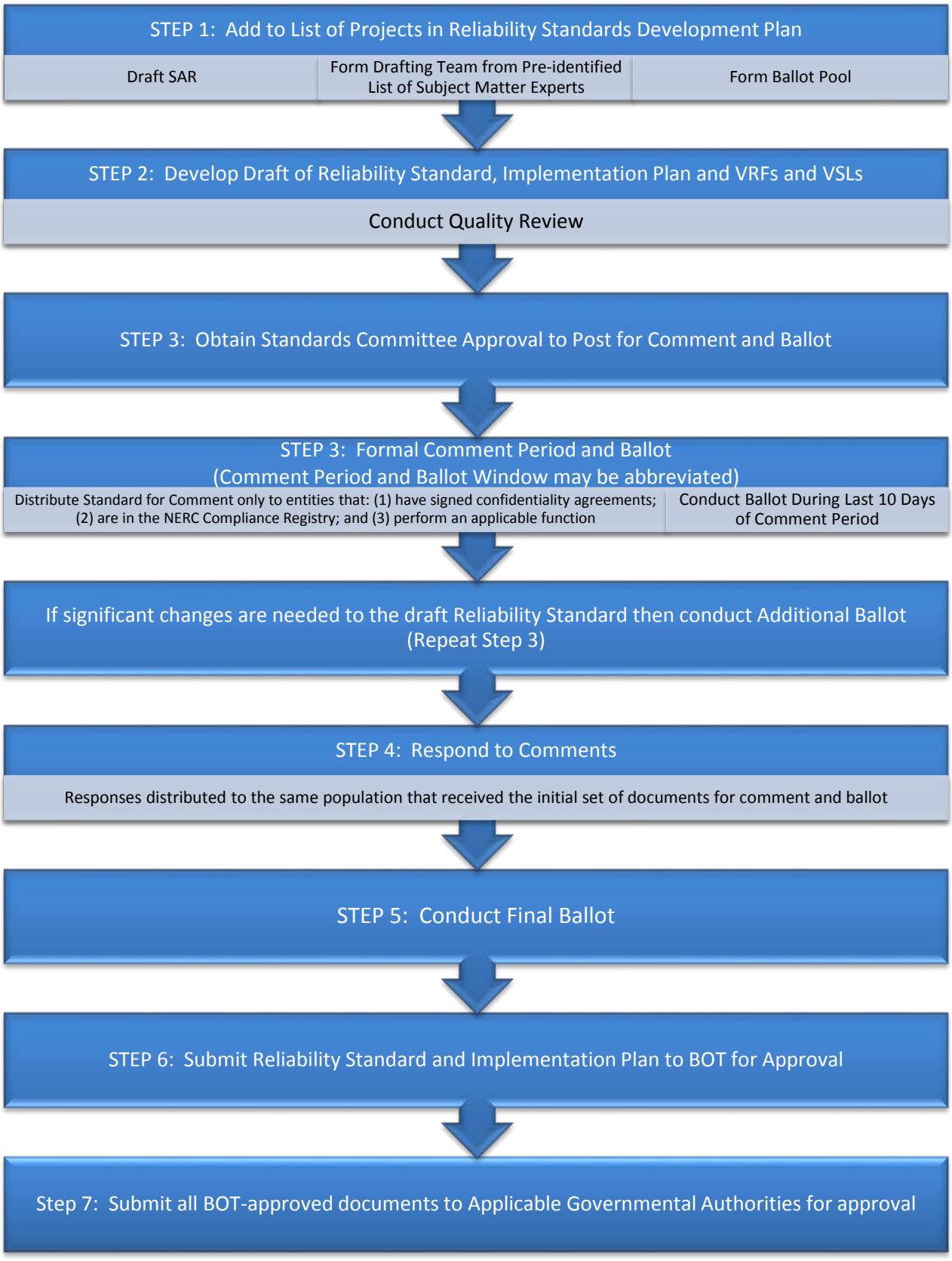


FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

Section 11.0: Process for Approving Supporting Documents

The NERC Standards Committee oversees the development and approval of documents identified as supporting documents to Reliability Standards approved by the Applicable Governmental Authority. ~~The following types of documents are samples of the types of supporting documents that may be developed to enhance stakeholder understanding and implementation of a Reliability Standard. These~~ Supporting documents may explain or facilitate ~~implementation~~ understanding of Reliability Standards but do not themselves contain mandatory Requirements subject to compliance review. Any Requirements that are mandatory shall be incorporated into the Reliability Standard in the Reliability Standard development process.

~~While most supporting documents are developed by the standard drafting team working to develop the associated Reliability Standard, any entity may develop a supporting document associated with a Reliability Standard.~~ This Section provides the mechanism by which any stakeholder may propose a supporting document to an approved Reliability Standard.

~~The Standards Committee shall authorize the posting of all supporting references[34] that are linked to an approved Reliability Standard. Prior to granting approval to post a supporting reference with a link to the associated Reliability Standard, the Standards Committee shall verify~~ The process outlined in this section is designed so that each~~that the~~ supporting document ~~has had~~ receives stakeholder review to verify the accuracy of the technical content prior to being posted as a supporting document to an approved Reliability Standard. ~~While the Standards Committee has the authority to approve the posting of each such reference, stakeholders, not the Standards Committee, verify the accuracy of the document's contents.~~

11.1: Types of Supporting Documents

The types of supporting documents that may be approved under this Section are listed below.

Type of Document	Description
Reference	Descriptive, technical information or analysis or explanatory information to support the understanding ~~and interpretation~~ of an approved Reliability Standard. ~~A standard reference may support the implementation of a Reliability Standard or satisfy another purpose consistent with the reliability and market interface principles.~~
~~Guideline~~	~~Recommended process that identifies a method of meeting a Requirement under specific conditions.~~
~~Supplement~~	~~Data forms, pro forma documents, and associated instructions that support the implementation of a Reliability Standard.~~
~~Training Material~~	~~Documents that support the implementation of a Reliability Standard.~~

[34] ~~The Standards Committee's Procedure for Approving the Posting of Reference Documents is posted on the Reliability Standards Resources web page.~~

~~Procedure~~	~~Step-wise instructions defining a particular process or operation. Procedures may support the implementation of a Reliability Standard or satisfy another purpose consistent with the reliability and market interface principles.~~
Lessons Learned	Documents designed to convey lessons learned related to an approved Reliability Standard. A Lessons Learned document is not intended to establish new Requirements under NERC's Reliability Standards or to modify Requirements in any existing Reliability Standards.
White Paper	An informal paper stating a position or concept. A white paper may have been used to propose preliminary concepts for a Reliability Standard or ~~one of the documents above~~a Reference document.

Supporting documents do not include documents that contain specific compliance approaches or examples of compliance. Such documents would be developed in accordance with the applicable NERC Compliance Monitoring and Enforcement Program process.

11.2: Process for Proposing and Evaluating Supporting Documents

Proposals for supporting documents to approved Reliability Standards shall be submitted to the NERC Reliability Standards Staff.

NERC Staff shall conduct a review of the proposed supporting document. In performing this review, NERC Staff may consult any technical resources it deems appropriate. The purpose of this review is to determine whether the proposed supporting document meets the following three criteria:

1. the document is a type of supporting document subject to this Section, as described in Section 11.1;
2. the document is consistent with the purpose and intent of the associated Reliability Standard; and
3. the document has received adequate stakeholder review to assess its technical adequacy, such as through a NERC technical committee review process, public comment period(s) held during the development of the associated Reliability Standard, or other stakeholder review process.

Where NERC Staff determines that the proposed supporting document has met the three criteria specified above, NERC Staff shall submit the proposed supporting document to the Standards Committee as specified in Section 11.3 below.

Where NERC Staff determines that the proposed supporting document does not meet the first or second criteria specified above, NERC Staff shall notify the submitter that the document will not be posted as a supporting document under this Section. This notification shall be made in writing with an explanation of the basis for the decision. NERC Staff shall also notify the Standards Committee of this determination at the next regularly scheduled Standards Committee meeting.

Where NERC Staff determines that the proposed supporting document meets the first and second criteria, but has not yet received adequate stakeholder review under the third criteria, NERC Staff shall make a recommendation to the Standards Committee to authorize the posting of the proposed supporting document for stakeholder review to verify the accuracy of the technical content. This comment period shall be for 30 days, unless directed otherwise by the Standards Committee. Upon conclusion of the comment period, NERC Staff shall compile the comments and provide to the submitter for consideration. If the submitter

modifies the proposed supporting document based on stakeholder comments, NERC Staff may post the document for additional comment periods to provide for sufficient vetting and technical review.

11.3: Approving a Supporting Document

Following its determination that the proposed supporting document has met the three criteria specified in Section 11.2, NERC Staff shall present the supporting document to the NERC Standards Committee with a recommendation regarding whether the Standards Committee should approve posting the supporting document with the approved Reliability Standard on the pertinent NERC website page(s).

Section 12.0: Process for Correcting Errata

From time to time, an error may be discovered in a Reliability Standard. Such errors may be corrected (i) following a Final Ballot prior to Board of Trustees adoption, (ii) following Board of Trustees adoption prior to filing with Applicable Governmental Authorities; and (iii) following filing with Applicable Governmental Authorities. If the Standards Committee agrees that the correction of the error does not change the scope or intent of the associated Reliability Standard, and agrees that the correction has no material impact on the end users of the Reliability Standard, then the correction shall be filed for approval with Applicable Governmental Authorities as appropriate. The NERC Board of Trustees has resolved to concurrently approve any errata approved by the Standards Committee.

Section 13.0: Process for Conducting Periodic Reviews of Reliability Standards

All Reliability Standards shall be reviewed at least once every ten years from the effective date of the Reliability Standard or the date of the latest Board of Trustees adoption to a revision of the Reliability Standard, whichever is later. If a Reliability Standard is approved by ANSI as an American National Standard, it shall be reviewed at least once every five years from the effective date of the Reliability Standard or the date of the latest Board of Trustees adoption to a revision of the Reliability Standard, whichever is later.

The *Reliability Standards Development Plan* shall include projects that address this five or ten-year review of Reliability Standards.

- If a Reliability Standard is nearing its five or ten-year review and has issues that need resolution, then the *Reliability Standards Development Plan* shall include a project for the complete review and associated revision of that Reliability Standard that includes addressing all outstanding governmental directives, all approved Interpretations, and all unresolved issues identified by stakeholders.
- If a Reliability Standard is nearing its five or ten-year review and there are no outstanding governmental directives, Interpretations, or unresolved stakeholder issues associated with that Reliability Standard, then the Reliability *Standards Development Plan* shall include a project solely for the "five-year review" of that Reliability Standard.

For a project that is focused solely on the five-year review, the Standards Committee shall appoint a review team of subject matter experts to review the Reliability Standard and recommend whether the American National Standard Institute-approved Reliability Standard should be reaffirmed, revised, or withdrawn. Each review team shall post its recommendations for a 45 calendar day formal stakeholder comment period and shall provide those stakeholder comments to the Standards Committee for consideration.

- If a review team recommends reaffirming a Reliability Standard, the Standards Committee shall submit the reaffirmation to the Board of Trustees for adoption and then to Applicable Governmental Authorities for approval. Reaffirmation does not require approval by stakeholder ballot.
- If a review team recommends modifying, or retiring a Reliability Standard, the team shall develop a SAR with such a proposal and the SAR shall be submitted to the Standards Committee for prioritization as a new project. Each existing Reliability Standard recommended for modification, or retirement shall remain in effect in accordance with the associated implementation plan until the action to modify or withdraw the Reliability Standard is approved by its ballot pool, adopted by the Board of Trustees, and approved by Applicable Governmental Authorities.

In the case of reaffirmation of a Reliability Standard, the Reliability Standard shall remain in effect until the next five or ten-year review or until the Reliability Standard is otherwise modified or withdrawn by a separate action.

Section 14.0: Public Access to Reliability Standards Information

14.1: Online Reliability Standards Information System

The NERC Reliability Standards Staff shall maintain an electronic copy of information regarding currently proposed and currently in effect Reliability Standards. This information shall include current Reliability Standards in effect, proposed revisions to Reliability Standards, and proposed new Reliability Standards. This information shall provide a record, for at a minimum the previous five years, of the review and approval process for each Reliability Standard, including public comments received during the development and approval process.

14.2: Archived Reliability Standards Information

The NERC Staff shall maintain a historical record of Reliability Standards information that is no longer maintained online. Archived information shall be retained indefinitely as practical, but in no case less than five years or one complete standard cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by the NERC Reliability Standards Staff of a written request.

Section 15.0: Process for Updating Standard Processes

15.1: Requests to Revise the Standard Processes Manual

Any person or entity may submit a request to modify one or more of the processes contained within this manual. The Standards Committee shall oversee the handling of each request. The Standards Committee shall prioritize all requests, merge related requests, and respond to each sponsor within 30 calendar days.

The Standards Committee shall post the proposed revisions for a 45 (calendar) day formal comment period. Based on the degree of consensus for the revisions, the Standards Committee shall:

a. Submit the revised process or processes for ballot pool approval;
b. Repeat the posting for additional inputs after making changes based on comments received;
c. Remand the proposal to the sponsor for further work; or
d. Reject the proposal.

The Registered Ballot Body shall be represented by a ballot pool. The ballot procedure shall be the same as that defined for approval of a Reliability Standard, including the use of an Additional Ballot if needed. If the proposed revision is approved by the ballot pool, the Standards Committee shall submit the revised procedure to the Board for adoption. The Standards Committee shall submit to the Board a description of the basis for the changes, a summary of the comments received, and any minority views expressed in the comment and ballot process. The proposed revisions shall not be effective until approved by the NERC Board of Trustees and Applicable Governmental Authorities.

Section 16.0: Waiver

While it is NERC's intent to use its ANSI-accredited Reliability Standards development process for developing its Reliability Standards, NERC may need to develop a new or modified Reliability Standard, definition, Variance, or implementation plan under specific time constraints (such as to meet a time constrained regulatory directive) or to meet an urgent reliability issue such that there isn't sufficient time to follow all the steps in the normal Reliability Standards development process.

The Standards Committee may waive any of the provisions contained in this manual for good cause shown, but limited to the following circumstances:

- In response to a national emergency declared by the United States or Canadian government that involves the reliability of the Bulk Electric System or cyber attack on the Bulk Electric System;
- Where necessary to meet regulatory deadlines;
- Where necessary to meet deadlines imposed by the NERC Board of Trustees; or
- Where the Standards Committee determines that a modification to a proposed Reliability Standard or its Requirement(s), a modification to a defined term, a modification to an interpretation, or a modification to a variance has already been vetted by the industry through the standards development process or is so insubstantial that developing the modification through the processes contained in this manual will add significant time delay.

In no circumstances shall this provision be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard.

A waiver request may be submitted to the Standards Committee by any entity or individual, including NERC committees or subgroups and NERC Staff. Prior to consideration of any waiver request, the Standards Committee must provide five business days notice to stakeholders.

Action on the waiver request will be included in the minutes of the Standards Committee. Following the approval of the Standards Committee to waive any provision of the Standard Process Manual, the Standards Committee will report this decision to the Standards Oversight and Technology Committee.[35] Actions taken pursuant to an approved waiver request will be posted on the Standard Project page and included in the next project announcement.

In addition, the Standards Committee shall report the exercise of this waiver provision to the Board of Trustees prior to adoption of the related Reliability Standard, Interpretation, definition or Variance.

Reliability Standards developed as a result of a waiver of any provision of the Standard Processes Manual shall not be filed with ANSI for approval as American National Standards.

[35] Any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.

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Summary of Proposed Revisions to the NERC Standard Processes Manual

Appendix 3A to the NERC Rules of Procedure

Revisions are proposed to Sections 2.1, 3.7, 6.0, 7.0, 8.0, and 11.0 of the NERC Standard Processes Manual (SPM), Appendix 3A to the NERC Rules of Procedure.

A redline of the proposed revisions is available on the Revisions to the NERC SPM page.

The proposed revisions are posted for a 45-day formal comment period from March 20, 2017 through May 3, 2017. An initial ballot will be conducted from April 24, 2017 – May 3, 2017. All comments should be submitted through the NERC Standards Balloting and Commenting System (SBS).

Background Information

Under the oversight of the NERC Standards Committee (SC), a small group consisting of Standards Committee Process Subcommittee (SCPS) members and NERC staff have reviewed specific sections of the NERC SPM for the purpose of proposing revisions to clarify and improve existing language and processes. Below is a summary of the revisions, which have been endorsed by the SCPS and the SC and are posted for ballot and comment.

Section 6.0 - Process for Conducting Field Tests

In March 2015, the SC endorsed developing draft revisions to the SC Charter and Section 6 of the SPM to develop more concise language and provide NERC's technical committees with additional oversight and authority over the technical aspect of field tests associated with Standards Authorization Requests and standards projects. NERC staff, along with members of the NERC Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee, worked together to develop the proposed revisions. The revisions were posted for informal comment from September 29, 2015 through October 28, 2015. In response to comments, revisions were made to clarify roles, responsibilities, and process steps.

Section 6.1 is revised to streamline the requirements for field tests to validate concepts that support the development of requirements (current Section 6.1) and field tests of technical concepts in a proposed new or revised Reliability Standard (current Section 6.2). Three new subsections are created:

> Proposed Section 6.1.1 summarizes the requirements for seeking approval of a field test. Under the proposed revisions, the requesting team must first identify a NERC technical committee to lead the effort to conduct the field test and seek approval from that technical committee to conduct the field test before seeking SC approval. The technical committee shall provide the SC with a recommendation regarding approval.

Proposed Section 6.1.2 provides that the lead NERC technical committee overseeing the field test may stop or modify the field test if it determines that the field test activity poses a reliability risk to the Bulk Power System. Prior to restarting a stopped field test, the requesting team must receive approval from the lead NERC technical committee and the SC in accordance with proposed Section 6.1.1.

Proposed Section 6.1.3 describes that a field test may be continued, modified, or terminated in the event a conclusion cannot be formulated within the time allotted in the field test plan, subject to the approval of the lead technical committee overseeing the field test.

Proposed Section 6.2 clarifies the processes governing communication and coordination for field tests. The proposed revisions clarify the process for seeking, approving, and making notifications with respect to compliance waivers for participating entities unable to comply with currently-enforceable Reliability Standards due to their participation in the field test. Proposed Section 6.2 also contains requirements for reporting on field test progress and results, including requirements to keep the NERC Board of Trustees informed regarding new and ongoing field tests and any requested compliance waivers.

Section 7.0 - Process for Developing an Interpretation

Revisions are proposed to improve the organization of the section. Additional revisions are proposed to clarify language regarding what constitutes a valid Interpretation, including clarifying that requests for approval of specific compliance approaches are not proper Interpretation requests and should instead be pursued through the applicable NERC and Regional Entity guidance processes (Section 7.2.1).

Recognizing that Interpretations provide clarity to existing standards and do not create new compliance obligations, revisions are proposed to streamline the process for posting and balloting Interpretations. Specifically, revisions are proposed to: (i) reduce the time for comment from 45 days to 30 days; (ii) eliminate the requirement for Interpretation drafting teams to respond in writing to each submitted comment; and (iii) eliminate the need for a separate final ballot following a successful initial or additional ballot.

Section 8.0 - Process for Appealing an Action or Inaction

Revisions are proposed to Sections 8.1 and 8.2 to specify that an appellant may withdraw its Level 1 or Level 2 appeal by providing written notice to the NERC Director of Standards. These revisions, which are based on lessons learned from previous appeals, would allow an appellant to withdraw its appeal in the event the issue is resolved to the appellant's satisfaction prior to the formal conclusion of the appeal.

Section 11.0 - Process for Approving Supporting Documents

Revisions are proposed to clarify that the scope of Section 11 is to define a process for approving the posting of supporting documents to approved Reliability Standards (i.e., Reliability Standards approved by applicable governmental authorities). New subsections are created to improve organization. The revisions are summarized as follows:

Section 11.1 defines the types of documents that may be posted as a supporting document to an approved Reliability Standard (Reference, Lessons Learned, White Paper). This section specifically excludes documents that contain specific compliance approaches, which are properly addressed through the applicable NERC and Regional Entity guidance processes.

Section 11.2 defines the process to be used to review and vet proposals for supporting documents. This process is designed so that each supporting document posted alongside an approved Reliability Standard: (i) is a Reference, Lessons Learned, or White Paper as defined in Section 11.1; (ii) is consistent with the purpose and intent of the associated Reliability Standard; and (iii) has had adequate stakeholder review to assess its technical adequacy. For example, stakeholders may have reviewed the document for technical adequacy during the standard development process for the associated standard. Alternatively, Section 11 provides a process for posting for stakeholder review those proposed supporting documents that have not yet been sufficiently vetted.

Section 11.3 provides for SC approval to post the supporting document along with the approved Reliability Standard on the NERC website.

Updates to Other Sections

Updates are made to Section 2.1 - Definition of a Reliability Standard, to reflect the currently effective definition of this term in the NERC Rules of Procedure.

Updates are made to Section 3.7 - Governmental Authorities, to allow for the inclusion of federal and provincial governments of non-U.S. North American jurisdictions that may approve Reliability Standards in the future.

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Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.net

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-003-2 – Frequency Response and Frequency Bias Setting		
Date Submitted:			
SAR Requester Information			
Name:	Troy Blalock – Chair of the NERC Resource Subcommittee		
Organization:	NERC Resource Subcommittee		
Telephone:	803.217.2040	Email:	Jblalock@scana.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 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 ERO and NERC Operating Committee approval. The items that need to be addressed are:

SAR Information
1. The IFRO calculation in BAL-003-1.1 needs to be revised due to inconsistencies identified in the 2016 Frequency Response Annual Analysis (FRAA) such as the IFRO values with respect to Point C and varying Value B. 2. Reevaluate the Eastern Interconnection Resource Contingency Protection Criteria. 3. Reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12) 4. Clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities. 5. The BAL-003-1.1 FRS Forms need enhancements that include, but may not be limited to, the ability to collect and submit FRSG performance data.
Purpose or Goal (How does this request propose to address the problem described above?):
Revise the BAL-003-1.1 standard and process documents to address: (1) the inconsistencies in calculation of IFROs due to interconnection Frequency Response performance changes of Point C and/or Value B; (2) the Eastern Interconnection Resource Contingency Protection Criteria; (3) the frequency nadir point limitations (currently limited to t_0 to t+12), (4) clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities, (5) the BAL-003-1.1 FRS Forms need enhancements that include, but may not be limited to, the ability to collect and submit FRSG performance data. Additionally, the supporting procedural and process steps may be removed from Attachment A and captured in an ERO and NERC Operating Committee approved Reference Document such that timely process improvements can be made as future lessons are learned. For additional information on items #1, 2 and 3, please refer to the 2016 FRAA Report.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
1. The IFRO calculation in BAL-003-1.1 needs to be revised due to inconsistencies identified in the 2016 Frequency Response Annual Analysis (FRAA) such as the IFRO values with respect to Point C and varying Value B. 2. Reevaluate the Eastern Interconnection Resource Contingency Protection Criteria. 3. Reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12) 4. Clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities. 5. The BAL-003-1.1 FRS Forms need enhancements that include, but may not be limited to, the ability to collect and submit FRSG performance data.

SAR Information
Brief Description (Provide a paragraph that describes the scope of this standard action.)
During the 2016 annual evaluation of the values used in the calculation of the IFRO the above mentioned issues 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 Criteria for each interconnection, (3) reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12), and (4) clarify language in Attachment A; (5) The BAL-003-1.1 FRS Forms need enhancements 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.
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.)
Consider revising the BAL-003-1.1 standard concerning #1 above through the standards development process to correct the inconsistency in the ratio of Point C to Value B. 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 performance. Consider revising the BAL-003-1.1 standard concerning #2 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 should revisit this issue for modifications to BAL-003-1.1 standard, and the Resources Subcommittee should recommend how the events are selected for each interconnection. Consider revising the BAL-003-1.1 standard concerning #3 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 frequency nadir point that exceeds the t_0 +12 seconds specified in BAL-003-1.1. 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-003-1.1 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

SAR Information
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 standard concerning #4 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.

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.

Reliability Functions		
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the end-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Reliability and Market Interface 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.

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

Related Standards	
Standard No.	Explanation
None	

Related SARs	
SAR ID	Explanation
None	

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.
WECC	None.

Version History

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

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Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	PER-003-1 Operating Personnel Credentials and PER-004-2 Reliability Coordination — Staffing		
Date Submitted:	TBD		
SAR Requester Information			
Name:	Patti Metro		
Organization:	Chair - Project 2016-EPR-01 PER		
Telephone:	(703) 907-5817	Email:	patti.metro@nreca.coop
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Need to add clarity to PER-003-1 that explains that the NERC certifications identified in this standard are described in the NERC System Operator Certification Program. The requirements of PER-004-2 are duplicative with requirements in several other standards that explain in detail the staffing requirements of personnel conducting the Reliability Coordinator function.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program. The Project 2016-EPR-01 PER Team recommends that PER-004-2 be retired.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
N/A
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Project 2016-EPR-01 PER team recommends that a clarifying footnote be added to PER-003-1 Requirement R1, R2 and R3 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program. The PER-004-2 standard falls within Paragraph 81 Criterion B7, because all of its requirements are redundant with requirements in other FERC-approved reliability standards that are in effect or soon to be effective. It is not necessary or efficient to maintain such duplicative requirements. Specifically, PER-004-2's requirements are duplicated in standards: • PER-003-1, R1 • PER-005-2, R2 and R3 • IRO-002-4, R3 and R4 • EOP-004-2, R2 • IRO-008-2, R1, R2, and R4 • IRO-009-2, R1 – R4 • IRO-010-2, R1 – R3 • IRO-014-3, generally • IRO-018-1, R1-R3

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 Requirements R1, R2 and R3 to ensure that stakeholders (now and in the future) understand the connection between the Standard and the Program Manual. The PRT suggests for consideration the following language be used for the footnote "The certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program." Concerning PER-004-2, the standards is duplicative and all requirements are covered in other reliability standards. Specifically, PER-003-1 R1 states that each Reliability Coordinator shall staff its Real-time operating positions with System Operators who have obtained and maintained a valid NERC Reliability Operator certificate. PER-005-2 R1 states that each Reliability Coordinator shall design, develop and deliver training to its System Operators based on a list of Bulk Electric System (BES) company specific Real-time reliability-related tasks. Additionally, PER-005-2 R3 states that Reliability Coordinators have to verify that their personnel are capable of performing each of those tasks. Moreover, in PER-004-2 R1, 24 hours per day, and seven days a week requirements are addressed by several NERC Reliability Standards and Requirements. These requirements cannot be accomplished without an entity having a 24/7 operation. IRO-002-4 R4 (enforceable 4/1/2017) requires that, "Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel…" In addition, IRO-002-4 R3 states that, "Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordination Area." EOP-004-2 covers continuous observation through its reporting timeframes to meet OE-417 for Loss of Monitoring. Additional coverage is ensured through IRO 008-2 R2, "Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address …(SOL) and (IROL) exceedances…" and R4 states, "Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes." Reinforcing the structure of the 24 hours per day, and seven days per week requirement is carried out by IRO-010-2 R1, requiring that Reliability Coordinator's maintain documented specifications for the data to perform Operational Planning analyses, Real-time monitoring, and Real-time Assessments. Real-time is defined as, "Present time as opposed to future times," while Real-time Assessment is defined as "An examination of existing and expected system

SAR Information
conditions, conducted by collecting and reviewing immediately available data." Using these definitions in the Reliability Standards further confirms that PER-004-2 Requirement 1 is duplicative and non-essential as its content is covered in multiple Reliability Standards. PER-004-2 Requirement R2 is duplicated in numerous Reliability Standards justifying the need for retirement of this requirement. As described below, the Standards and requirements of IRO-002-4, IRO-008-2, IRO-009-2, IRO-010-2, IRO-014-3 and IRO-018-1 adequately ensure that protocols are in place to allow the Reliability Coordinator operating personnel to have the best available information at all times. IRO-002-4, R3 states that the Reliability Coordinator shall monitor Facilities and work with neighboring Reliability Coordinator areas to identify SOL and IROL exceedances within its area. In order to ensure compliance with this Standard and Requirement, particular attention must be placed on SOLs, IROLs, and inter-tie facility limits. IRO-008-2 ensures that the Reliability Coordinator performs analyses and assessments to prevent instability, uncontrolled separation, or cascading. R1, R2, and R4 of this Standard specifically require that an Operational Planning Analysis is performed to: • assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area, • ensure that coordinated plans are developed for the next-day operations to address these exceedances, and • execute Real-time Assessments at least once every 30 minutes. To maintain compliance with the IRO-008-2 Standard, the Reliability Coordinator must place particular attention on SOLs and IROLs. IRO-009-2 builds on IRO-008-2 by ensuring prompt action to prevent or mitigate instances where IROLs are exceeded. Through the Requirements of this Standard, assurances are made that the Reliability Coordinator has one or more Operating Processes, Procedures, or Plans that identify actions to take, or actions to direct others to take, to mitigate the magnitude and duration of an IROL exceedance identified in their Assessments. IRO-010-2 provides data specifications that affords the Reliability Coordinator the specific data necessary to perform its Operational Planning Analyses, Real-time monitoring, Real-time Assessments

SAR Information
and ensures that a protocol exists to resolve any data conflicts. This Standard ensures that the Reliability Coordinator has the best available information at all times to maintain compliance. IRO-014-3 ensures that each Reliability Coordinator's operations are coordinated so that they will not adversely impact other Reliability Coordinator Areas and preserve the reliability benefits of interconnected operations. This Standard again builds on the coordination of the Operational Analyses and Real-time Assessments which requires the Reliability Coordinator to have the best available information at all times to maintain compliance. IRO-018-1 established three requirements for Real-time monitoring and analysis capabilities to support reliable operations. Real-time monitoring involves observing operating status and operating values in Real-time to ensure awareness of system conditions. Through this Standard, processes and procedures are established for evaluating the quality of Real-time data and to provide assurance that any action taken addresses any data quality issues so that Real-time monitoring and Real-time Assessments performed by the Reliability Coordinator contains the best available information at all times.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.

Reliability Functions		
☐	Transmission Planner	Develops a one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the end-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.

Reliability and Market Interface Principles	
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

Version History

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review Template: PER-003-1 Operating Personnel Credentials

December 2016

Introduction

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten (10) years, or once every five (5) years for Reliability Standards approved by the American National Standards Institute as an American National Standard.[1] The Reliability Standard identified above has been included in the current cycle of periodic reviews. The Review Team shall consist of two (2) subgroups; a Standing Review Team which is appointed annually by the Standards Committee for periodic reviews, and a stakeholder Subject Matter Expert (SME) team.[2] Consistent with Section 13 of the Standards Processes Manual, the Standards Committee may use a public nomination process to appoint the stakeholder SME team, or may use another method to appoint that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the periodic review, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the periodic review.
Together, the Standing Review Team and SME stakeholder team are the Review Team for a particular periodic review project and complete their portion of the template below.

The purpose of the template is to collect background information, pose questions to guide a comprehensive review of the Standard(s) by the Review Team, and document the Review Team's considerations and recommendations. The Review Team will post the completed template containing its recommendations for information and stakeholder input as required by Section 13 of the NERC Standard Processes Manual.

Review Team Composition

	Standing Review Team	**Plus Section 13 (SMEs):**
Non-CIP Standards	Chairs of the following NERC Standing Committees[3]: • Standards Committee (Also, the SC chair or his/her delegate from the	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the

[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[2] Other reliability standards included as part of the Review Team's periodic review were PER-004-2 (included in a separate, concurrent, report) and PER-001-0.2 (which was approved for retirement on March 31, 2017 and therefore not included in either report).

[3] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

	SC will chair the Standing Review Team)[4] • Planning Committee • Operating Committee The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.	Standing Review Team to conduct its review of the standard(s) and complete the template below.
CIP Standards	Chairs of the following NERC Standing Committees[5]: • Standards Committee (Also, the SC chair or his/her delegate from the SC will chair the Standing Review Team) • CIPC	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.

The Review Team will use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation from one of the following three (3) choices:

1. Recommend reaffirming the Standard as steady-state (Green); or
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or
3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to or a retirement of the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

A completed Periodic Review Template and any associated documentation should be submitted by email to Darrel Richardson at darrel.richardson@nerc.net.

[4] The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team's review of a standard s), and another SC member to chair a review of another standard(s).

[5] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

Applicable Reliability Standard: PER-003-1
Team Members (include name and organization): 1. Patti Metro, Nation Rural Electric Cooperative Association 2. Lauri Jones, Pacific Gas and Electric Company 3. Heather Morgan, EDP Renewables North America LLC 4. Jeffrey Sunvick, Western Area Power Administration 5. Jimmy Womack, Southwest Power Pool 6. Brad Perrett, Minnesota Power 7. Carolyn White Wilson, Duke Energy Corporation 8. Michael B. Hoke, PJM Interconnection LLC 9. Danny W. Johnson, Xcel Energy 10. Darrel Richardson, NERC Senior Standards Developer 11. Candice Castaneda, NERC Counsel 12. Michael Brytowski, Great River Energy PMOS Representative
Date Review Completed:

Background Information *(to be completed initially by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) directives associated with the Reliability Standard? (*If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)*

   ☐ Yes

   ☒ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? (*If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard*.)

   ☐ Yes

   ☒ No

   Please explain:

3. Is the Reliability Standard one of the most violated Reliability Standards?

☐ Yes

☒ No

If so, does the cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes

☐ No

Please explain:

Questions for the Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

I. Quality

1. **Reliability Need, Paragraph 81:** Do any of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? *Use Attachment 2: Paragraph 81 Criteria to make this determination.*

   ☐ Yes

   ☒ No

   Please summarize your application of Paragraph 81 Criteria, if any:

2. **Clarity:** From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN or issue associated with it, or is frequently violated because of ambiguity?
   a. Does the Reliability Standard have obviously ambiguous language?
   b. Does the Reliability Standard have language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?
   d. Should the requirements stand alone as is, or should they be consolidated with other standards?
   e. Is the Reliability Standard complete and self-contained?
   f. Does the Reliability Standard use consistent terminology?

☒ Yes

☐ No

Please summarize your assessment: Although the response to the parent question above is "No" examination of its subparts (a) – (g) has led the Review Team to recommend a clarifying revision. The Project 2016-EPR-01 PER Review Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the NERC System Operator Certification Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), Violation Severity Levels (VSL) and Time Horizons) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines?

☒ Yes

☐ No

If you answered "No," please identify which elements require revision, and why:

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard, or for coordination with other Reliability Standards?

☐ Yes

☒ No

If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions or other factors?

   ☐ Yes

   ☒ No

   If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

7. **Practicable**:
   a. Can the Reliability Standard be practically implemented?

      ☒ Yes

      ☐ No

   b. Is there a concern that it is not cost effective as drafted?

      ☐ Yes

      ☒ No

   Please summarize your assessment of the practicability of the standard:

8. **Consideration of Generator and Transmission Interconnection Facilities:** Is responsibility for generator interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard? **N/A to this standard.**

   ☐ Yes

   ☐ No

   Guiding Questions:

   a. If the Reliability Standard is applicable to Generator Owners and/or Generator Operators, is there any ambiguity about the inclusion of generator Interconnection Facilities? (If generation Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   b. If the Reliability Standard is not applicable to Generator Owners and/or Generator Operators, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, Generator Owners that own and/or

Generator Operators that operate relevant generator Interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

c. If the Reliability Standard is applicable to Transmission Operators and/or Distribution Providers, is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

9. **Results Based Standard:** Is the Reliability Standard drafted as a results-based standard?

☒ Yes

☐ No

If not, please summarize your assessment:

Guiding Questions:

a. Does the Reliability Standard address performance, risk (prevention) and capability?

☒ Yes

☐ No

b. Does the Reliability Standard follow the RBS format (for example, Requirement and Part structure) in Attachment 1?

☐ Yes

☒ No

c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard[6]?

☒ Yes

☐ No

II. Content

[6] Ten Benchmarks of an Excellent Reliability Standard, posted at Page 626 of: http://www.nerc.com/pa/Stand/Resources/Documents/DT_Reference_Manual_Resource_Package_080114.pdf

10. **Technical accuracy:** Is the content of the Requirements technically correct, including identifying who does what and when?

    ☒ Yes

    ☐ No

    If not, please summarize your assessment:

11. **Functional Model:** Are the correct functional entities assigned to perform the requirements, consistent with the Functional Model?

    ☒ Yes

    ☐ No

    If not, please summarize your assessment:

12. **Applicability:** Is there a technical justification for revising the applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?

    ☐ Yes

    ☒ No

    If so, please summarize your assessment:

13. **Reliability Gaps:** Are the appropriate actions for which there should be accountability included, or is there a gap?

    ☐ Yes

    ☒ No

    If a gap is identified, please explain:

14. **Technical Quality:** Does the Reliability Standard have a technical basis in engineering and operations?

    ☒ Yes

    ☐ No

    If not, please summarize your assessment:

15. **Does the Reliability Standard reflect a higher solution than the lowest common denominator?**

☒ Yes

☐ No

If not, please summarize your assessment:

16. **Related Regional Reliability Standards**: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide Standard?

☐ Yes

☒ No

If yes, please identify the regional standard(s) and summarize your assessment:

RED, YELLOW GREEN GRADING

Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow –is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the Standard through the Standards development process for retirement or revision. The reasons for the Review Team's conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team, minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow or Red.

Recommendation

The answers to the questions above, along with its Red, Yellow, Green grading and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☒ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☐ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program; and (ii) the connection between the Standard and the Program Manual.

Preliminary Recommendation posted for industry comment (date): January 10, 2017

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☒ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☐ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR)*:

The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program; and (ii) the connection between the Standard and the Program Manual.

Date submitted to Standards Committee: June 14, 2017

Attachment 1: Results-Based Standards

Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber-attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[7] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[7] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?

The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

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Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber-attacks. (*footnote omitted*)

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Attachment 3: Independent Expert Evaluation Process

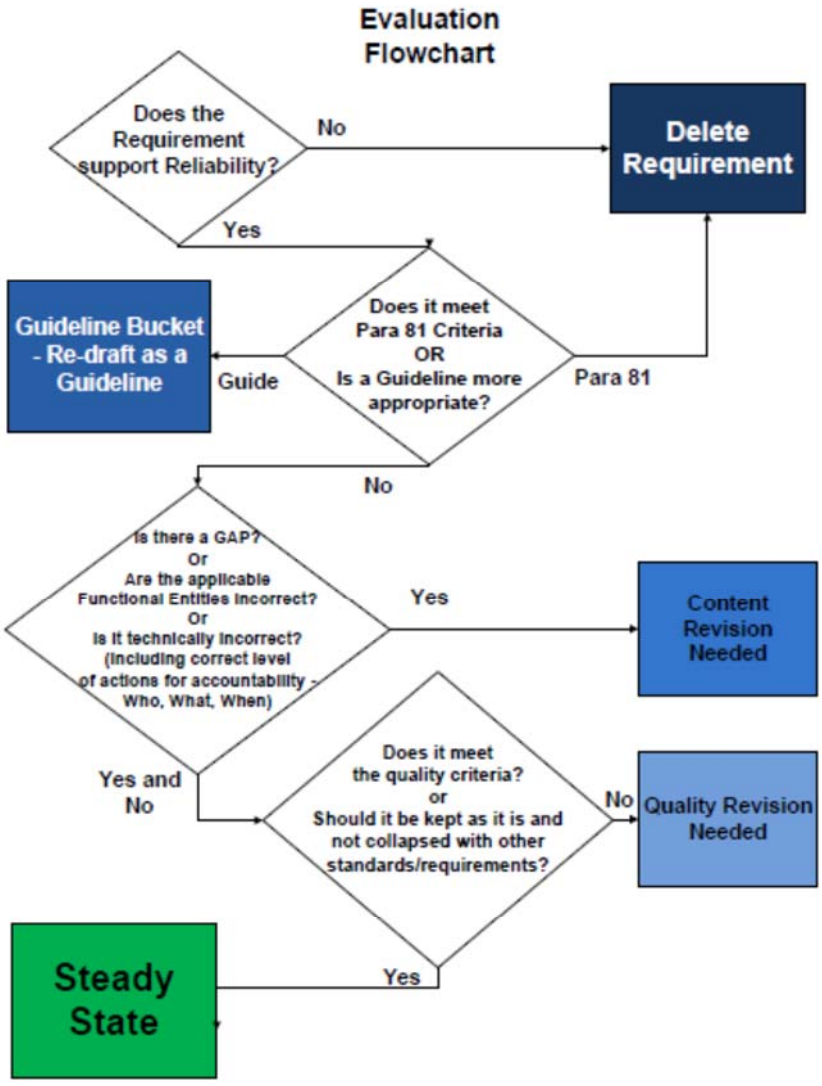

Figure 1: Evaluation Flow Chart

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review Template: PER-004-2 Reliability Coordination - Staffing

December 2016

Introduction

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[3] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

	SC will chair the Standing Review Team)[4] • Planning Committee • Operating Committee The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.	Standing Review Team to conduct its review of the standard(s) and complete the template below.
CIP Standards	Chairs of the following NERC Standing Committees[5]: • Standards Committee (Also, the SC chair or his/her delegate from the SC will chair the Standing Review Team) • CIPC	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.

The Review Team will use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation from one of the following three (3) choices:

1. Recommend reaffirming the Standard as steady-state (Green); or
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or
3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to or a retirement of the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

A completed Periodic Review Template and any associated documentation should be submitted by email to Darrel Richardson at darrel.richardson@nerc.net.

[4] The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team's review of a standard s), and another SC member to chair a review of another standard(s).

[5] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

Applicable Reliability Standard: PER-004-2
Team Members (include name and organization): 1. Patti Metro, Nation Rural Electric Cooperative Association 2. Lauri Jones, Pacific Gas and Electric Company 3. Heather Morgan, EDP Renewables North America LLC 4. Jeffrey Sunvick, Western Area Power Administration 5. Jimmy Womack, Southwest Power Pool 6. Brad Perrett, Minnesota Power 7. Carolyn White Wilson, Duke Energy Corporation 8. Michael B. Hoke, PJM Interconnection LLC 9. Danny W. Johnson, Xcel Energy 10. Darrel Richardson, NERC Senior Standards Developer 11. Candice Castaneda, NERC Counsel 12. Michael Brytowski, Great River Energy PMOS Representative
Date Review Completed:

Background Information *(to be completed initially by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) directives associated with the Reliability Standard? (*If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)*

   ☐ Yes

   ☒ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? (*If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard*.)

   ☐ Yes

   ☒ No

   Please explain:

3. Is the Reliability Standard one of the most violated Reliability Standards?

☐ Yes

☒ No

If so, does the cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes

☐ No

Please explain:

Questions for the Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

I. Quality

1. **Reliability Need, Paragraph 81:** Do any of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? *Use Attachment 2: Paragraph 81 Criteria to make this determination.*

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   This standard falls within Paragraph 81 Criterion B7, because all of its requirements are redundant with requirements in other FERC-approved reliability standards that are in effect or soon to be effective. It is not necessary or efficient to maintain such duplicative requirements and PER-004-2 may be retired with little to no effect on reliability. Specifically, PER-004-2's requirements are duplicated in standards:

   - PER-003-1, R1
   - PER-005-2, R2 and R3
   - IRO-002-4, R3 and R4
   - EOP-004-2, R2
   - IRO-008-2, R1, R2, and R4
   - IRO-009-2, R1 – R4

- IRO-010-2, R1 – R3
- IRO-014-3, generally
- IRO-018-1, R1-R3

Please refer to Page 10 of this document for a detailed justification for retirement of these requirements.

2. **Clarity:** From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN or issue associated with it, or is frequently violated because of ambiguity?
   a. Does the Reliability Standard have obviously ambiguous language?
   b. Does the Reliability Standard have language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?
   d. Should the requirements stand alone as is, or should they be consolidated with other standards?
   e. Is the Reliability Standard complete and self-contained?
   f. Does the Reliability Standard use consistent terminology?

   ☐ Yes

   ☒ No

   Please summarize your assessment:

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

   ☐ Yes

   ☒ No

   Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), Violation Severity Levels (VSL) and Time Horizons) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines?

   ☒ Yes

   ☐ No

   If you answered "No," please identify which elements require revision, and why:

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard, or for coordination with other Reliability Standards?

   ☐ Yes

   ☒ No

   If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions or other factors?

   ☐ Yes

   ☒ No

   If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

7. **Practicable**:
   a. Can the Reliability Standard be practically implemented?

      ☒ Yes

      ☐ No

   b. Is there a concern that it is not cost effective as drafted?

      ☐ Yes

      ☒ No

   Please summarize your assessment of the practicability of the standard:

8. **Consideration of Generator and Transmission Interconnection Facilities:** Is responsibility for generator interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard? **Not Applicable.**

   ☐ Yes

   ☐ No

Guiding Questions:

a. If the Reliability Standard is applicable to Generator Owners and/or Generator Operators, is there any ambiguity about the inclusion of generator Interconnection Facilities? (If generation Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

b. If the Reliability Standard is not applicable to Generator Owners and/or Generator Operators, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, Generator Owners that own and/or Generator Operators that operate relevant generator Interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

c. If the Reliability Standard is applicable to Transmission Operators and/or Distribution Providers, is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

9. **Results Based Standard:** Is the Reliability Standard drafted as a results-based standard?

☒ Yes

☐ No

If not, please summarize your assessment:

Guiding Questions:

a. Does the Reliability Standard address performance, risk (prevention) and capability?

☒ Yes

☐ No

b. Does the Reliability Standard follow the RBS format (for example, Requirement and Part structure) in Attachment 1?

☒ Yes

☐ No

c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard[6]?

☒ Yes

☐ No

II. Content

10. **Technical accuracy:** Is the content of the Requirements technically correct, including identifying who does what and when?

☒ Yes

☐ No

If not, please summarize your assessment:

11. **Functional Model:** Are the correct functional entities assigned to perform the requirements, consistent with the Functional Model?

☒ Yes

☐ No

If not, please summarize your assessment:

12. **Applicability:** Is there a technical justification for revising the applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?

☐ Yes

☒ No

If so, please summarize your assessment:

13. **Reliability Gaps:** Are the appropriate actions for which there should be accountability included, or is there a gap?

[6] Ten Benchmarks of an Excellent Reliability Standard, posted at Page 626 of: http://www.nerc.com/pa/Stand/Resources/Documents/DT_Reference_Manual_Resource_Package_080114.pdf

☐ Yes

☒ No

If a gap is identified, please explain:

14. **Technical Quality:** Does the Reliability Standard have a technical basis in engineering and operations?

☒ Yes

☐ No

If not, please summarize your assessment:

15. **Does the Reliability Standard reflect a higher solution than the lowest common denominator?**

☒ Yes

☐ No

If not, please summarize your assessment:

16. **Related Regional Reliability Standards**: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide Standard?

☐ Yes

☒ No

If yes, please identify the regional standard(s) and summarize your assessment:

RED, YELLOW GREEN GRADING

Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow –is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the Standard through the Standards development process for retirement or revision. The reasons for the Review Team's conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team, minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow or Red.

Recommendation

The answers to the questions above, along with its Red, Yellow, Green grading and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☐ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☒ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

PER-004-2 R1 is duplicative and all requirements are covered in other reliability standards. Specifically, PER-003-1 R1 states that each Reliability Coordinator shall staff its Real-time operating positions with System Operators who have obtained and maintained a valid NERC Reliability Operator certificate. PER-005-2 R1 states that each Reliability Coordinator shall design, develop and deliver training to its System Operators based on a list of Bulk Electric System (BES) company specific Real-time reliability-related tasks. Additionally, PER-005-2 R3 states that Reliability Coordinators have to verify that their personnel are capable of performing each of those tasks.

Moreover, in PER-004-2 R1, 24 hours per day, and seven days a week requirements are addressed by several NERC Reliability Standards and Requirements. These requirements cannot be accomplished without an entity having a 24/7 operation. IRO-002-4 R4 (enforceable 4/1/2017) requires that, "Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel…" In addition, IRO-002-4 R3 states that, "Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordination Area." EOP-004-2 covers continuous observation through its reporting timeframes to

meet OE-417 for Loss of Monitoring. Additional coverage is ensured through IRO 008-2 R2, "Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address …(SOL) and (IROL) exceedances…" and R4 states, "Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes." Reinforcing the structure of the 24 hours per day, and seven days per week requirement is carried out by IRO-010-2 R1, requiring that Reliability Coordinator's maintain documented specifications for the data to perform Operational Planning analyses, Real-time monitoring, and Real-time Assessments. Real-time is defined as, "Present time as opposed to future times," while Real-time Assessment is defined as "An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data." Using these definitions in the Reliability Standards further confirms that PER-004-2 Requirement 1 is duplicative and non-essential as its content is covered in multiple Reliability Standards.

PER-004-2 Requirement R2 is duplicated in numerous Reliability Standards justifying the need for retirement of this requirement. As described below, the Standards and requirements of IRO-002-4, IRO-008-2, IRO-009-2, IRO-010-2, IRO-014-3 and IRO-018-1 adequately ensure that protocols are in place to allow the Reliability Coordinator operating personnel to have the best available information at all times.

IRO-002-4, R3 states that the Reliability Coordinator shall monitor Facilities and work with neighboring Reliability Coordinator areas to identify SOL and IROL exceedances within its area. In order to ensure compliance with this Standard and Requirement, particular attention must be placed on SOLs, IROLs, and inter-tie facility limits.

IRO-008-2 ensures that the Reliability Coordinator performs analyses and assessments to prevent instability, uncontrolled separation, or cascading. R1, R2, and R4 of this Standard specifically require that an Operational Planning Analysis is performed to:

- assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area,
- ensure that coordinated plans are developed for the next-day operations to address these exceedances, and
- execute Real-time Assessments at least once every 30 minutes.

To maintain compliance with the IRO-008-2 Standard, the Reliability Coordinator must place particular attention on SOLs and IROLs.

IRO-009-2 builds on IRO-008-2 by ensuring prompt action to prevent or mitigate instances where IROLs are exceeded. Through the Requirements of this Standard, assurances are made that the Reliability Coordinator has one or more Operating Processes, Procedures, or Plans that identify actions to take, or

actions to direct others to take, to mitigate the magnitude and duration of an IROL exceedance identified in their Assessments.

IRO-010-2 provides data specifications that affords the Reliability Coordinator the specific data necessary to perform its Operational Planning Analyses, Real-time monitoring, Real-time Assessments and ensures that a protocol exists to resolve any data conflicts. This Standard ensures that the Reliability Coordinator has the best available information at all times to maintain compliance.

IRO-014-3 ensures that each Reliability Coordinator's operations are coordinated so that they will not adversely impact other Reliability Coordinator Areas and preserve the reliability benefits of interconnected operations. This Standard again builds on the coordination of the Operational Analyses and Real-time Assessments which requires the Reliability Coordinator to have the best available information at all times to maintain compliance.

IRO-018-1 established three requirements for Real-time monitoring and analysis capabilities to support reliable operations. Real-time monitoring involves observing operating status and operating values in Real-time to ensure awareness of system conditions. Through this Standard, processes and procedures are established for evaluating the quality of Real-time data and to provide assurance that any action taken addresses any data quality issues so that Real-time monitoring and Real-time Assessments performed by the Reliability Coordinator contains the best available information at all times.

Preliminary Recommendation posted for industry comment (date): January 10, 2017

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☐ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☒ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR)*:

See justification above.

Date submitted to Standards Committee: June 14, 2017

Attachment 1: Results-Based Standards

Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber-attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[7] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[7] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?

The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber-attacks. (*footnote omitted*)

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Attachment 3: Independent Expert Evaluation Process

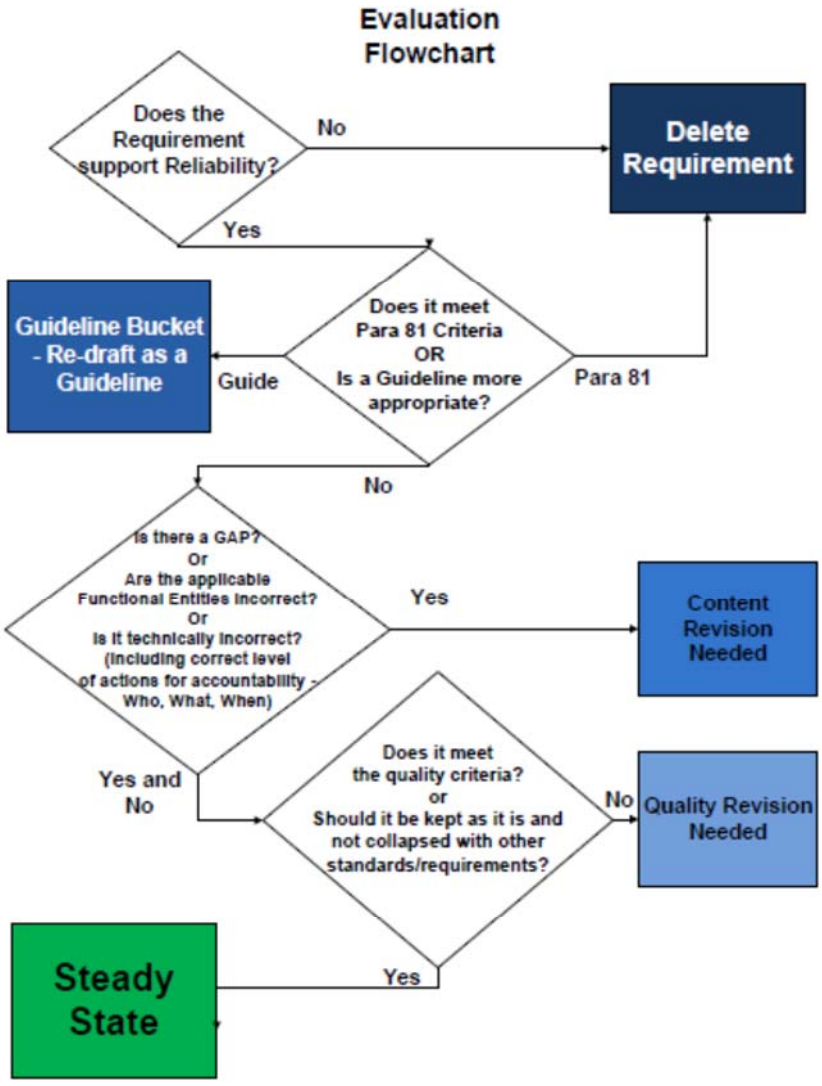

Figure 1: Evaluation Flow Chart

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	BAL-002-2 – Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event		
Date Submitted:			
SAR Requester Information			
Name:	Darrel Richardson		
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SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to Existing Standard		☐ Withdrawal of Existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated: "Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with

SAR Information
the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time. NERC may also propose an equally efficient and effective alternative." Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard, 158 FERC ¶ 61,030 at P 37 (2017) ("FERC Order"). *See also, id.*, at P 2 and PP 35-36.
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to allow the standard drafting team (SDT) for Project 2017-06, Disturbance Control to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a Balancing Contingency Event, or alternatively propose modifications that address the Commission concerns.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify the standard, Violation Risk Factors, Violation Severity Levels, and implementation plan and shall work with compliance on an accompanying RSAW to address the FERC Order directives described above.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDTs execution of this SAR requires the SDT to address the FERC Order directives described above or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address either (A) revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time; or (B) proposing an equally efficient and effective alternative.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.
☐ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐ Distribution Provider	Delivers electrical energy to the end-use customer.
☐ Generator Owner	Owns and maintains generation facilities.
☐ Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐ Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐ Market Operator	Interface point for reliability functions with commercial functions.

Reliability Functions	
☐ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles		
Applicable Reliability Principles (Check all that apply).		
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.	
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.	
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.	
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.	
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.	
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.	
Does the proposed Standard comply with all of the following Market Interface Principles?		Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.		Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.		Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.		Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.		Yes

Related Standards	
Standard No.	Explanation
None	

Related SARs	
SAR ID	Explanation
None	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.

Regional Variances	
SERC	None.
SPP	None.
WECC	None.

Version History

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary of Proposed Revisions

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits** (SOL). The electronic form must be submitted by **8 p.m. Eastern, Friday, August 12, 2016.**

Additional information is available on the project page. If you have questions, contact Lacey Ourso, Standards Developer by email or phone at 404.446.2581.

Background Information regarding Project 2015-09 Establish and Communicate System Operating Limits

The Facilities Design, Connections, and Maintenance (FAC) Reliability Standards fulfill an important reliability objective for determining and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) used in the reliable operation of the Bulk Electric System (BES). The purpose of Project 2015-09 – Establish and Communicate System Operating Limits is to revise these requirements. Revisions are necessary to eliminate overlap with approved Transmission Planning (TPL) requirements,[1] enhance consistency with Transmission Operations (TOP)[2] and Interconnection Reliability Operations (IRO)[3] standards, and address other concerns in the existing FAC standards regarding the determination and communication of SOLs and IROLs. As outlined in the Standards Authorization Request (SAR), the scope of the standards development project includes development of new or revised requirements and/or NERC Glossary definitions to provide clarity and consistency for establishing SOLs and IROLs, and to address potential reliability issues resulting from application of the current NERC Glossary definitions for SOL and IROL.[4]

High-level Overview of Proposed Revisions to FAC Reliability Standards

In developing revisions to the FAC Reliability Standards and definitions related to SOL and IROL, the standard drafting team (SDT) has focused on alignment with how SOLs and IROLs are treated in the approved TOP and IRO Reliability Standards (enforceable beginning April 1, 2017). The SDT believes this shift is critical to align the approach for how the System is actually operated as a result of the wholesale

[1] *See*, TPL-001-4
[2] *See*, TOP-001-3, TOP-002-4, TOP-003-3
[3] See, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, IRO-017-1
[4] The SAR was sponsored and submitted by the Project 2015-03 -Periodic Review of System Operating Limit Standards periodic review team (PRT).

revisions to the TOP and IRO Reliability Standards and reflects the manner in which operations are currently conducted. Below is a detailed explanation of how the proposed revisions complement the TOP/IRO revisions. The proposed changes to the FAC standards support a more reliable, dynamic approach to operating within actual limits that exist on the system, as opposed to reliance on "operating limits" that were set well in advance.

Overview of How Proposed Revisions Align with Revised TOP and IRO Reliability Standards

The revisions proposed to the FAC standards were designed to work together with the approved TOP and IRO Reliability Standards. The combination of the proposed revisions to the FAC standards and the TOP and IRO Reliability Standards, including the defined terms contained in those standards (Operational Planning Analysis (OPA)[5], Real-time Assessment (RTA)[6], and Operating Plans) when executed together will result in maintaining reliable BES performance. Thus, it is imperative that your review of the proposed revisions to the FAC standards is conducted with a full understanding of how these standards will work together with the approved TOP and IRO Reliability Standards. The proposed FAC revisions standing alone will not provide a complete picture of how different functional entities will work together to establish the appropriate operational limits, and then actually operate to them.

Under the approved TOP and IRO Reliability Standards:

- TOP-002-4 Requirement R1 requires the TOP to have an OPA that will allow it to assess whether its planned operations for the next day will exceed any of its SOLs.
- TOP-002-4 Requirement R2 requires that the TOP have an Operating Plan to address potential "SOL exceedances" identified as a result of its OPA.
- TOP-001-3 Requirement R13 requires that the TOP perform a RTA at least once every 30 minutes.

[5] NERC Glossary defines Operational Planning Analysis (OPA) as, "An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" [NERC Glossary as of June 24, 2016]

[6] NERC Glossary defines Real-time Assessment (RTA) as, "An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) [NERC Glossary as of June 24, 2016]

- TOP-001-3 Requirement R14 requires that the TOP initiate its Operating Plan to mitigate an "SOL exceedance" identified as part of its Real-time monitoring or RTA.

For more information on the TOP/IRO revisions, please visit the Project 2014-03 Revisions to TOP/IRO Reliability Standards project page.

Overview of Proposed Revisions to FAC-011-3, FAC-014-2 and Defined Terms SOL and SOL Exceedance

As outlined in greater detail below, the SDT is proposing to revise the existing definition of SOL and create a new NERC Glossary definition for "SOL Exceedance." The new definitions support the conceptual distinction between operating practices and the SOL itself. The SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity operates to those SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by the entity. The revised definition of SOL and new definition of "SOL Exceedance" will work together with the future-enforceable TOP and IRO Reliability Standards, including the definitions of OPA, RTA and Operating Practices as follows:

- The TOP is required to have an OPA to assess whether its planned operations for the next day will exceed any of its SOLs (*see*, TOP-002-4, Requirement R1). If the OPA identifies potential SOL exceedances, the TOP is required to have an Operating Plan to address those potential SOL exceedances (*see*, TOP-002-4, Requirement R2).
- Additionally, the TOP is required to perform a RTA at least once every 30 minutes (*see*, TOP-001-3 Requirement R13). If the TOP identifies that an SOL is being exceeded in Real-time operations, the TOP will implement the mitigating strategies identified in its Operating Plan (*see*, TOP-001-3 Requirement R14).
- In other words, an "SOL Exceedance" is simply unacceptable system performance that must be mitigated in accordance with the action plan the TOP has laid out in its Operating Plan.
- A potential SOL Exceedance may be identified by an OPA, or an actual SOL Exceedance may be identified by an RTA.
- The Operating Plan can include specific Operating Procedures or more general Operating Processes. The TOP Operating Plans include both pre- and post- Contingency mitigation plans and strategies. The pre-Contingency strategies are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans and strategies are actions that the TOP will implement after the Contingency occurs to bring the system back within limits.
- The Operating Plans contain adequate details regarding the appropriate timelines to escalate the level of mitigation to ensure BES performance is maintained as required by the RC SOL Methodology.

The proposed definition of SOL Exceedance (described in further detail below) provides clarity regarding what is deemed to be "unacceptable system performance." When the conditions identified in the definition of SOL Exceedance occur, the TOP must be prepared

to implement its action plan outlined in its Operating Plan to mitigate that particular condition and return the system back within acceptable limits.

The SDT believes that the proposed definitions and revisions to the FAC standards will eliminate confusion between the operating practices used by the TOP and the actual limits themselves. The revisions provide clarity regarding (1) what the limits are, (2) what it means to exceed them, and (3) how an "SOL Exceedance" should be addressed by the TOP in operations planning (TOP-002-4 Requirement R2) and Real-time operations (TOP-001-3 Requirement R14).

Purpose of 30-day Informal Comment Period

As outlined above, the scope of Project 2015-09 includes revision of the requirements for determining and communicating SOLs and IROLs used in the reliable planning and operation of the BES. This informal 30-day posting does not encompass the entire scope of work that the SDT will undertake for the project. Rather, this is only a piece of the complete work. However, the SDT believes it to be the most critical area. The direction taken with regard to these standards set the foundation for building a proper SOL methodology to ensure that SOLs are established and communicated in a manner that will later ensure reliable BES operation when carried out in operations.

Reliability Standards and definitions that **are included** (as part of this limited, informal posting):

- FAC-011-3 – System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 – Establish and Communicate System Operating Limits
- Revisions to definition of System Operating Limit (SOL)
- New definition of SOL Exceedance

Reliability Standards and definitions that **are NOT included** (as part of this limited, informal posting):

- FAC-010-3 – System Operating Limits Methodology for the Planning Horizon
- Revisions to definition of Interconnection Reliability Operating Limit (IROL)
- Necessary revisions to existing Reliability Standards to incorporate concepts included in new defined term "SOL Exceedance" (*i.e.,* TOP-002-4 – capitalize SOL Exceedance to incorporate usage of defined term).

Although this is only an informal posting, the SDT underscores the importance of this posting. The SDT believes that the revisions proposed represent a significant improvement in how the industry works together to ensure reliability by establishing SOLs and operating to them in a manner that is reflective of the changing technology, and dynamic manner where entities have the ability to assess pre- and post-

Contingency performance in Real-time based on actual operating conditions. For these reasons, the SDT requests that commenters please take the time to review the background materials from the Project 2015-09 SOL Technical Conference which outline all of the various issues that were considered by the team, and discussed in an open forum with industry members. The SDT believes that we have captured the essence of the direction that the industry would like to take, but this is the opportunity for the team to continue to improve on proposed revisions by obtaining early feedback. The SDT looks forward to hearing and understanding your perspective for each of the very specific issues and associated questions raised below. In order for the SDT to thoroughly understand and incorporate your feedback into the future standard development, please do not simply provide yes or no responses. Please provide us with your perspective. Give us as much detail as you can. If you disagree with the SDT's direction, please provide an alternative approach that you believe will be superior to the one that the SDT proposed.

Proposed Revisions, Background Information and Questions

A. Definitions

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations.	The current definition of SOL (and the related FAC standards) presume an operating paradigm whereby a study or analysis is performed ahead of time to establish an SOL; the SOL is then communicated to operators; and the operators are given an operating plan to operate below the SOL with the presumption that doing so will result in acceptable pre- and post-Contingency system performance in Real-time operations. However, due to changes in the TOP and IRO Reliability Standards, along with advancements in technology from the time that the FAC standards were originally drafted, this is not reflective of how the system is actually operated. Today, entities continuously assess system performance and identify potential events in Real-time, based on *actual* operating conditions. The proposed revisions to the SOL definition, coupled with the proposed new definition of SOL Exceedance (see below) and the revisions to the FAC standards will support the concept that the SOL is the actual operating parameter; and eliminate confusion between "what the limits are" verses "how the system should be operated given the limits."	Existing definition of SOL: "The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings) • transient stability ratings (applicable pre- and post-Contingency stability limits) • voltage stability ratings (applicable pre- and post-Contingency voltage stability)

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	Given this shift, there is no need for the existing SOL definition language that includes concepts of "the most limiting criteria," "specified system configuration," "operation within acceptable reliability criteria," and "pre- and post-Contingency." These concepts are covered in the future-enforceable TOP and IRO Reliability Standards (including the defined terms contained therein: OPA, RTA, and Operating Plans), along with the proposed revisions to the FAC standards. As a result of the proposed revisions, the Facility Ratings, System voltage limits, and stability limitations are SOLs, all of the time, regardless of which one is "the most limiting." Also, as detailed below, the definition of "SOL Exceedance" will complement the revised definition of SOL by specifically identifying operating conditions that are deemed unacceptable, and require action by the TOP to mitigate. The proposed revisions use the term "stability limitation" rather than "transient stability limit," "voltage stability limit" or the Glossary term "Stability Limit." The intent of the SDT is that "stability limitation" is intentionally broad and can be used to encompass a number of different types of stability-related limitations or phenomenon, including, but not limited to, weighted short-circuit ratio (WSCR), sub-synchronous resonance (SSR), phase angle limitations, fault-interrupting capability of breakers, transient voltage limitations on equipment, and geomagnetic-induced currents on equipment. The Glossary term "Stability Limits" is not appropriate because it is limited to the maximum power flow value; this is too restrictive and not technology-neutral, as tools allow entities	• system voltage limits (applicable pre- and post-Contingency voltage limits)"

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	to monitor and control parameters other than maximum power flow values in order to demonstrate reliable stability performance. For more information regarding the proposed revisions to the SOL definition (and the definition of SOL Exceedance), please reference the Project 2014-03 – TOP and IRO Reliability Standards white paper entitled, "System Operating Limit Definition and Exceedance Clarification."	

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
SOL Exceedance: An operating condition characterized by any of the following: • Actual or pre-Contingency flow on a Facility is above the Normal Rating; • Calculated post-Contingency flow on a Facility is above the highest Emergency Rating;	As explained above, under the proposed revisions, the SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity remains within those SOLs will vary depending upon the particular Operating Plan of the entity. When the operating conditions listed in the definition of SOL Exceedance are identified – through an OPA or RTA – the TOP will take the actions outlined in its Operating Plan to mitigate the condition. The SDT did not include specific timing requirements for each condition listed in the definition, because the appropriate timing for operator response can vary depending upon the particular facts and	**Mapping to existing FAC standards or definitions under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- Identifies performance requirements that RC SOL Methodology shall include. If the definition of SOL Exceedance is pursued by the SDT, the definition would be incorporated into existing standards that currently rely on the concept of an

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
• Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs; • Actual or pre-Contingency bus voltage is outside normal System voltage limits; • Calculated post-Contingency bus voltage is outside the emergency system voltage limits; • Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs; or, • Operating parameters indicate the next Contingency could result in instability.	circumstances. However, it is expected (and required) that the TOP Operating Plan specifically identify the allowable response time, along with the specific actions to be taken by the operator, in mitigating the condition. The bulleted items carry forward the types of limitations that are identified in the current definition of SOL, and incorporate the concepts of acceptable/unacceptable system performance, as currently contained in FAC-011-3 Requirement R2. For bullet item 3: This operating condition exists when the calculated post-Contingency flow falls below the highest Emergency Rating; however, the flow remains at a level where there is not sufficient time to reduce the flow to an acceptable level after the Contingency occurs. In this operating condition, the operator would be required to take pre-Contingency action, and could not rely on a post-Contingency mitigation plan. Because pre-Contingency action is required, the condition is deemed to be an "SOL Exceedance." For bullet items 4 and 5: Normal and emergency System voltage limits must respect the voltage limitations specified in the TO or GO Facility Ratings methodology (pursuant to FAC-008-3). Normal voltage limits are typically applicable for the pre-Contingency state, while emergency voltage limits are applicable for the post-Contingency state. "SOL Exceedance" with respect to these voltage	"SOL exceedance." The intent is not to change the meaning of the existing standards, rather the SDT believes that the proposed definition captures the existing meaning, but simply provides greater clarity through listing the specific types of conditions in the "SOL Exceedance" definition. In concert with proposing the new "SOL Exceedance" definition, the SDT would propose revisions (only as necessary) to existing standards to incorporate the newly defined Glossary term. Below are a few examples, but are not intended to represent a comprehensive or complete listing: • 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 result in an SOL Exceedance of its System Operating Limits (SOLs).

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
	limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments recognize whether auto-reactive devices are sufficient for maintaining voltage within acceptable limits pre- or post-Contingency.	• TOP-002-4 Requirement R2 - Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) Exceedance(s) identified as a result of its Operational Planning Analysis as required in Requirement R1. • TOP-001-3 Requirement R14 - Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL Exceedance identified as part of its Real-time monitoring or Real-time Assessment.

B. Proposed Revisions to FAC-011-3

Proposed Reliability Standard: FAC-011-4, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.	As outlined above, the SDT has incorporated the concepts contained in the existing FAC-011-3 Requirement R1 into the proposed revisions to the definitions of SOL and SOL Exceedance, along with the proposed revisions to FAC-011 and FAC-14. The existing Parts 1.1 through 1.3 are incorporated into the proposed new requirements, as detailed below.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – Sentence 1.

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and	Under FAC-008-3, Facility Ratings are established by Facility owners (TOs and GOs) consistent with the owner's methodology. These Facility Ratings are communicated to the RCs and TOPs. RCs and TOPs incorporate these ratings into their tools and processes and use the ratings in establishing their SOLs. Because TOs and GOs are not required to use any sort of continent-wide methodology for establishing the Facility	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 Requirements R1, R2 and R3– GOs and TOs are required to have a methodology for developing Facility Ratings. • FAC-008-3 Requirement R6– GOs and TOs shall establish Facility Ratings consistent with its methodology.

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
the Transmission Operators in its Reliability Coordinator Area.	Ratings, it is possible for owners to use varying/different methodologies. This can create problems in establishing the appropriate SOL because the variations in Facility Rating methodologies may result in different or inconsistent types of Facility Ratings used in operations. If the RCs and TOPs are using different sets of Facility Ratings in conducting their respective outage coordination studies, OPAs, and RTAs, this may create a potential risk to reliability. The intent of Requirement R2 is for the RC SOL Methodology to identify the method that its TOPs will use in determining which of the Facility Ratings provided by the owner (under FAC-008-3) are appropriate for use in establishing SOLs for use in operations. As outlined above, under the revised definition of SOL, the Facility Ratings will be the SOL. The second sentence of Requirement R2 is intended to ensure that the RC and the TOP are using the same Facility Ratings, which will eliminate the risk identified above.	• FAC-008-3 Requirements R7 and R8– must provide their Facility Ratings to the RC, TOP and other functional entities. **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- RC SOL Methodology shall include requirement that SOLs provide BES performance, and following certain prescribed conditions/states, remain within their Facility Ratings.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state System voltage limits to be used in operations. The method shall: **3.1.** Require that System voltage limits are not outside of the Facility voltage ratings; **3.2.** Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements; **3.3.** Require that System voltage limits are above UVLS relay settings; **3.4.** Identify the lowest allowable System voltage limit; **3.5.** Address the use of common System voltage limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area; and,	There is no Reliability Standard that specifically requires establishment and communication of System voltage limits; however, System voltage limits are used in the definition of SOL and are an important aspect of reliable operations. The SDT believes it is important for the Reliability Standards to assign responsibility for the establishment and communication of System voltage limits. Like Facility Ratings, System voltage limits should be consistent between TOPs and RCs throughout all operations processes. The proposed Requirement R3 will result in the RC SOL Methodology requiring the TOP to determine System voltage limits for use in operations, consistent with the RC methodology.	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 – Requires Facility Owner to establish Facility Ratings, which includes voltage ratings.[7] • VAR-001-4 Requirement R1 – The TOP specifies the system voltage schedule (which is either a range or a target value associated with a tolerance band) as part of its plan to operate within SOLs (and IROLs). **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2) - RC SOL Methodology shall include requirement that SOLs provide BES performance with regard to certain prescribed conditions (pre-Contingency state, following certain identified single-

[7] Definition of Facility Ratings: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
3.6. Address coordination of System voltage limits between adjacent Transmission Operators in its Reliability Coordinator Area.		Contingencies) and remain within their thermal and voltage limits. [Proposed definitions of SOL and SOL Exceedance and Requirement R3 carry this forward.] • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. [Proposed Part 3.1 carries this forward.] • Parts 3.2-3.6 were not clearly identified in the previous FAC standards; these are "new" requirements added by the SDT to provide clarity regarding steady-state system voltage limits.

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall include in its SOL Methodology the method for	As detailed above, the existing definition of SOL provides that the SOL is "based upon" certain criteria, including transient stability ratings. The proposed	**Background regarding existing standards *not* under revision by SDT:**

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
determining the stability limitations to be used in operations. The method shall: **4.1.** Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following: **4.1.1.** steady-state voltage stability; **4.1.2.** transient voltage response; **4.1.3.** angular stability; and, **4.1.4.** System damping. **4.2.** Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies: **4.2.1.** Loss of one of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault: • generator;	revisions to the SOL definition make clear that the SOLs "are" the reliability limits, which include stability limitations. Additionally, under the current standards, there are no set continent-wide stability limitations criteria for use in determining SOLs. Under existing FAC-011-3 Requirement R2, the RC has flexibility with regard to establishing stability limitations; provided the system performance requirements in the standard are met. While the existing language in Requirement R2 (and portions of Requirement R3) do provide some "continent-wide" uniformity, the requirements do not provide sufficient clarity regarding the distinction between establishing stability limitations and acceptable system performance requirements/response. The proposed revisions continue to allow the RC to have flexibility in its SOL Methodology for developing stability limitations. This ensures the RC is able to appropriately tailor the methodology to meet the particular needs of its system, since a "one size fits all" approach is not appropriate for stability limitations. However, the proposed requirement does set a number of minimum	• IRO-005-3.1a, Requirement R1 (Parts 1.2 and 1.3) – Each RC should monitor its RC Area parameters, including pre and post contingent element stability conditions. • IRO-008-2, Requirement R1 – Each RC shall perform an OPA that will assess whether next day planned operations will exceed SOLs or IROLs within its Wide-area. • MOD-001-2, Requirement R1 (Part 1.1) – Each TOP that calculates TFC or TTC shall have a written methodology that describes how those values are calculated, including the pre- and post-Contingency limitations for transient and voltage stability limits and other SOLs. **Mapping to existing FAC standards under revision:** • FAC-014-2, Requirement R6 (Parts 6.1 and 6.2) – Planning Authority shall provide multiple contingencies causing stability limits, and the limits, to the

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
• Transmission circuit; • transformer; • shunt device; • single pole of a direct current line. **4.2.2.** Loss of any multiple Contingencies identified in Requirement R5. **4.3.** Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch; **4.4.** Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8; **4.5.** Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and, **4.6.** Specify how stability limitations will be established when there is an impact to	required attributes (specific to stability limitations) that must be contained within the RC SOL Methodology. The proposed approach by the SDT is for the RC SOL Methodology to continue to set the method for how stability limitations for its RC Area must be established. Under proposed Requirement R4, the RC SOL Methodology must: Part 4.1 - Specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied. Part 4.2 - Meet the performance criteria for certain identified Contingencies (listed in the standard). Part 4.3 - Describe how instability risks are identified. The SDT changed the existing language of "anticipated" to "realistic." (See, FAC-011-3 Part 3.6) The SDT believes "anticipated" could be broadly interpreted to mean anticipated by the planners (in planning horizon), instead of what is realistically anticipated by the operators in the operations time horizon. Part 4.4 – Incorporates concepts from the existing FAC-011-3 Part 3.3, and requires the RC to consider the	Reliability Coordinator, or note to the RC if there are none. *[Maps to proposed Part 4.4]* • FAC-011-3 Requirement R2 (Part 2.1) - *[Maps to proposed Part 4.1, with new requirement providing specific types of criteria that must be considered.]* • FAC-011-3 Requirement R2 (Part 2.2) - *[Maps to proposed Part 4.2]* • FAC-011-3 Requirement R2 (Part 3.6) - *[Maps to proposed Part 4.3]* • FAC-011-3 Requirement R3 (Parts 3.1 and 3.5) – *[Maps to proposed Part 4.5]*

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
more than one TOP in its Reliability Coordinator Area.	stability limitations provided by the Planning Coordinator. Part 4.5 – This language combines some components of existing FAC-011-3 Parts 3.1, 4.3, and 3.5, but removes the blanket requirement for the study to include the entire RC Area. The revised language allows the RC to have flexibility to determine the appropriate study model, and required supporting details. Part 4.6 – The SDT believes that this Part will improve reliability by requiring the RC SOL Methodology to specify the appropriate manner to develop stability limitations, when those limitations impact more than one TOP in its RC Area. A companion requirement is FAC-014-3 Requirement R3, which requires the RC to determine the stability limitations when there is an impact to more than one TOP in its RC Area. (*See*, the proposed FAC-014-3 Requirement R3 for further explanation).	

Proposed Reliability Standard: FAC-011-4, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.	Currently effective Reliability Standard TOP-004-2 Requirement R3 requires the TOP operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its RC. This requirement was retired by the TOP/IRO project because it was addressed by the new TOP-001-3 Requirements R12 and R14 (which are not limited by single or multiple contingencies) in combination with existing FAC-011-3 Part 3.3 and FAC-014-2 Requirement R6 (which work collectively to establish how multiple Contingencies are considered in IROLs and SOLs). The proposed Requirement R5 maintains the existing approach that the RC SOL Methodology shall specify the multiple Contingencies for use in establishing stability limitations and IROLs. Further, it improves upon the existing requirement by allowing the RC SOL Methodology to identify multiple Contingencies beyond those identified by the planners.	**Background regarding existing standards *not* under revision by SDT:** • TOP-001-3 Requirements R12 and R14 **Mapping to existing FAC standards under revision:** • FAC-011-3 Part 3.3 • FAC-014-2 Requirement R6

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including: **6.1.** Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation; **6.2.** Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation; **6.3.** Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations versus intra-area oscillations); and, **6.4.** Unacceptable impacts on neighboring Reliability	Regional differences exist in the criteria for determining which subset of SOLs are IROLs. The SDT discussed the regional differences among the various RC Areas, and several similarities emerged, including: (1) loss of load criteria, (2) loss of generation criteria, (3) non-localized or uncontained instability, and (4) impact on neighboring RC Area. The SDT evaluated the potential positive and negative impacts of creating continent-wide requirements, and determined that establishing minimum criteria that must be considered as part of the RC Methodology would benefit reliability; while continuing to allow necessary flexibility. The proposed language provides greater uniformity by identifying the criteria to be considered by the RC in establishing IROLs. The criteria must describe, at a minimum, the severity and extent of what is/not allowable with regarding to: (1) loss of load, (2) quality of supply loss, (3) thresholds for inter-area oscillations, and (4) impacts on neighboring RC Areas within its Interconnection. This minimum IROL criteria will provide for greater continent-wide consistency as it ensures all RCs consider and identify what is allowable for each criteria. The SDT believes while this does change the current state – where no mandatory minimum criteria exist- it still allows for the RC to have the necessary flexibility to design its IROL	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – RC SOL Methodology must include a description of how to identify the subset of SOLs that qualify as IROLs. • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
Coordinator Areas within an Interconnection.	methodology so that it can meet the reliability issues present in, and possibly unique to, its RC Area.	

Proposed Reliability Standard: FAC-011-4, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.	For the most part, the substance of this requirement is not changed from the existing standard; it was previously contained in a part (*i.e.,* FAC-011-3 Part 3.7) and is now a stand-alone requirement. The only change is that the 30 minute time-period is specifically identified, whereas in the previous requirement only stated T_v.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state, where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address: **8.1.** Thresholds for initiating evaluation of potential impacts; **8.2.** A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and, **8.3.** A review of the operating state experience for the purpose of determining whether an IROL should be established.	In Order No. 817, FERC noted that, "operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability." The SDT believes that in certain circumstances, such as in response to forced outages or similar unforeseen events, Real-time operating conditions can occur such that a RTA identifies an operating state where the next Contingency could result in instability, uncontrolled separation or Cascading outages. When this operating condition occurs in Real-time, it is clear that System Operator(s) are expected to take urgent action to mitigate the N-1 insecure operating state. What is unclear, however, is whether this operating condition constitutes some sort of an "IROL exceedance" or mandates that other IROL-related Reliability Standards should be applied. The proposed requirement requires the RC SOL Methodology to prescribe a method for how to address the above-described Real-time operating state. This will allow for consistency by System Operators within an RC Area in responding to the Real-time operating state when tools or analysis indicate abnormal post-Contingency conditions (*e.g.*, unsolved Contingencies, high post-Contingency overloads). While the requirement treats the operating state similar to, and equally important to, what prepared response must be	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_V.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	in place for resolving an IROL-type issue, the requirement does not focus on formally establishing the limit, but instead allowing the System Operator to act with urgency to address the temporary operating state at hand. Also Part 8.3 requires the RC Methodology prescribe an after-the-fact review of the operating state experience for the purpose of determining whether an IROL should be established in accordance with the RC SOL Methodology.	

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the SOL Methodology, prior to the effective date, to: **9.1.** Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology;	For the most part, the substance of this requirement is not changed from the existing standard. A clarification was added to Part 9.1 that RCs should issue its SOL Methodology, and any associated changes, to the other RCs *within* its Interconnection.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R4 – Requires the RC to issue its SOL Methodology, and any changes to the methodology, to its adjacent RCs and any RCs indicating a reliability-related need; to each PC and TP that models portions of its

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
9.2. Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and, **9.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.		RC Area; and, each TOP that operates in its RC Area.

C. Proposed Revisions to FAC-014-3

Proposed Reliability Standard: FAC-014-3, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.	The current FAC-014-2 Requirement R1 requires that the RC ensure SOLs and IROLs are established pursuant to its SOL Methodology. This creates a situation where the RC is responsible for "ensuring" actions out of its control. The proposed revisions do not change the intent of the standard –that the RC develop the SOL Methodology for establishing SOLs in its RC Area, and the TOP following the RC SOL Methodology in establishing those SOLs. Accordingly, the proposed Requirement R2 requires that the TOP establish SOLs as required by the RC SOL Methodology. The SDT believes this clarifies the appropriate responsibilities of the respective functional entities, while not creating ambiguity in the requirements in requiring the RC to do something that the TOP is, in all actuality, required to do. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R2		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.	The SDT has removed language from the existing FAC-014-3 Requirement R2 that states the TOP, "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the RC will issue a "Directive," or that TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and these SOLs must be established in accordance with (*i.e.*, pursuant to the "direction") identified in the RC's SOL Methodology.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts	The proposed approach by the SDT is that the RC SOL Methodology will set the method for how all stability limitations for its RC Area must be established (see, proposed	**Mapping to existing FAC standards under revision:**

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.	FAC-011-4 Requirement R4). The RC SOL Methodology must, among other things, specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied (see, proposed FAC-011-4 Part 4.1); meet the performance criteria for certain identified Contingencies listed in the standard (see, proposed FAC-011-4 Part 4.2); and describe how instability risks are identified (see, proposed FAC-011-4 Part 4.3). The TOP is required to establish stability limitation SOLs in accordance with everything outlined in the RC SOL Methodology. However, in addition to what is outlined above, the SDT believes that to the extent there are stability limitations that may impact more than one TOP in its RC Area, the RC should be responsible for determining these stability limitations (in accordance with its RC SOL Methodology – see, proposed FAC-011-4 Part 4.6). The purpose of providing a separate requirement for the RC to address this specific type of stability limitation is to provide clarity that there may be a stability limitation that is not appropriately labeled an "IROL," and thus, would not be covered by proposed Requirement R1. It is the position of the SDT that not all stability limitations are automatically "IROLs." For example, there may be instances of local, contained instability that are not appropriately designated	• N/A: This proposed requirement addresses what the SDT believes to be a gap in the existing requirements.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	an "IROL," because labeling it as an IROL may require the TOP to take actions such as pre-Contingency load shedding, that is not warranted, and could actually cause a bigger reliability impact. However, when the stability limitation impacts more than one TOP, the SDT believes the RC should have primary responsibility for establishing that SOL.	

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area. **4.1.** The Reliability Coordinators shall provide any updates to the SOL	The proposed Requirement R4 maintains the part of existing FAC-014-3 Requirement R5 which requires the TC to send the SOLs for its RC Area to adjacent RCs. The SDT has created a new/separate requirement related to communicating established IROLs (see proposed FAC-014-4 Requirement R5). The SDT added Part 4.1 to require the RC to provide updates to the SOLs to the impacted TOPs. It is expected that the RC and TOPs will establish a mutually agreeable means (pursuant to IRO-010-2 and TOP-003-3) for exchanging dynamically determined Facility Ratings or stability limitations.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.		

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area: **5.1.** Identification of the Facilities that are critical to the derivation of the IROL.	See above explanation. This requirement was previously combined with the requirement to provide updates to both SOLs and IROLs (existing FAC-014-3 Requirement R5). The SDT separated these into two requirements – one for SOL and one for IROL – so that greater detail could be provided regarding the type of IROL-information that must be communicated by the RC.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
5.2. The value of the IROL and its associated IROL T_V. **5.3.** The associated Contingency(ies). **5.4.** The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).		

Proposed New/Revised Requirement	Explanation of Proposed Revision	Relevant Requirements in Existing Reliability Standard(s)
R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area: **6.1.** Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.	In FERC Order No. 777, FERC directed NERC to develop a means to assure that IROLs are communicated to transmission owners (*see*, P6 and P41). The purpose of this proposed requirement is to address the concerns raised by FERC in Order No. 777. The RC is required to provide the IROL information identified in Part 6.1 to Transmission Owners and Generator Owners in its RC Area. The SDT included Generator Owners because it believes that GOs, in addition to TOs, need to receive information relating to facilities that are critical to the derivation of the IROL. The SDT did not combine this with proposed Requirement R5 because the team believes that the owners only need IROL information related to their facilities that are critical to the	**Mapping to existing FAC standards under revision:** • N/A: This proposed requirement is intended to address the issues raised in FERC Order No. 777.

Proposed New/Revised Requirement	Explanation of Proposed Revision	Relevant Requirements in Existing Reliability Standard(s)
	derivation of the IROL. However, the owners do not need the information identified in proposed Parts 5.2 through Part 5.4, and further, this information may contain sensitive operator information not appropriate for open-ended sharing.	

Proposed Reliability Standard: FAC-014-3, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	The SDT did not make substantive changes to this requirement; however, the requirement previously existed as a "part" of a requirement and it is now a stand-alone requirement.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Part 5.2 – Requires the TOP to provide its SOLs to the RC and Transmission Service Providers in its portion of the RC Area.

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include: **8.1.** The type of the instability (*e.g.*, voltage collapse, angular instability, transient voltage dip criteria violation); **8.2.** The Contingencies which result in the instability; **8.3.** Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss that was employed (or invoked) to address the instability; and, **8.4.** Any Corrective Action Plan associated with the instability.	Under proposed FAC-011-4 Part 4.4, the RC SOL Methodology must consider the stability limitations provided by the Planning Coordinator. Also, proposed FAC-014-3 Requirements R2 and R3, the applicable entities are required to establish stability limitations (if any) in accordance with the RC SOL Methodology. This requirement is intended to complement proposed FAC-011-4 Part 4.4 by ensuring that the planning entities provide the results of their stability analysis, including a list of those contingencies that are expected to produce the more severe System impacts, to the affected RC and TOP. This information may be relevant to the operating conditions for which the RC and TOP are determining SOLs. Further, FAC-013-2 requires that the PC have a methodology and annual assessment that identifies the weaknesses and limiting Facilities that could limit the ability of the Transmission System to reliably transfer energy. The results of the assessment, including the methodology used in the analysis, may contain information that may be relevant to the RC and TOP analysis for determining SOLs (and IROLs).	**Background regarding existing standards *not* under revision by SDT:** • TPL-001-4 • FAC-013-2 **Mapping to existing FAC standards under revision:** • FAC -011-3 Part 3.3 • FAC -014-2 Requirement R6

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

Glossary Term(s):

System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations. ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

SOL Exceedance: An operating condition characterized by any of the following:

- Actual or pre-Contingency flow on a Facility is above the Normal Rating
- Calculated post-Contingency flow on a Facility is above the highest Emergency Rating
- Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs
- Actual or pre-Contingency bus voltage is outside normal System voltage limits
- Calculated post-Contingency bus voltage is outside the emergency system voltage limits
- Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs
- Operating parameters indicate the next Contingency could result in instability.

DRAFT

A. Introduction

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

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

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** TBD

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state System voltage limits to be used in operations. The method shall:

3.1. Require that System voltage limits are not outside of the Facility voltage ratings;

3.2. Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements;

3.3. Require that System voltage limits are above UVLS relay settings;

3.4. Identify the lowest allowable System voltage limit;

3.5. Address the use of common System voltage limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area; and,

3.6. Address coordination of System voltage limits between adjacent Transmission Operators in its Reliability Coordinator Area.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limitations to be used in operations. The method shall:

4.1. Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies:

4.2.1. Loss of one of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault:

- generator;
- Transmission circuit;
- transformer;
- shunt device;
- single pole of a direct current line.

4.2.2. Loss of any multiple Contingencies identified in Requirement R5.

4.3. Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch;

4.4. Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8;

4.5. Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and,

4.6. Specify how stability limitations will be established when there is an impact to more than one TOP in its Reliability Coordinator Area.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.

R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including:

6.1. Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation;

6.2. Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation;

6.3. Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations versus intra-area oscillations); and,

6.4. Unacceptable impacts on neighboring Reliability Coordinator Areas within an Interconnection.

R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.

R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state, where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address:

8.1. Thresholds for initiating evaluation of potential impacts;

8.2. A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and,

8.3. A review of the operating state experience for the purpose of determining whether an IROL should be established.

R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the SOL Methodology, prior to the effective date, to:

9.1. Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology;

9.2. Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and,

9.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

DRAFT

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-3

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

   4.1.3. Planning Coordinator

   4.1.4. Transmission Planner

5. **Effective Date:** TBD

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.

R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.

R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.

R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area.

4.1. The Reliability Coordinators shall provide any updates to the SOL values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.

R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area:

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5.1. Identification of the Facilities that are critical to the derivation of the IROL;

5.2. The value of the IROL and its associated IROL T_V;

5.3. The associated Contingency(ies); and,

5.4. The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).

R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area:

6.1. Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.

R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include:

8.1. The type of the instability (*e.g.*, voltage collapse, angular instability, transient voltage dip criteria violation);

8.2. The Contingencies which result in the instability;

8.3. Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss that was employed (or invoked) to address the instability; and,

8.4. Any Corrective Action Plan associated with the instability.

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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.

North American Electric Reliability Corporation
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Atlanta, GA 30326
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Standard Development Timeline

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

Description of Current Draft

This is the first draft of 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

Anticipated Actions	Date
45-day formal comment period with additional ballot	TBD
10-day final ballot	TBD
Board	TBD

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

A. Introduction

1. **Title:** Cyber Security – Control Center Communication Networks
2. **Number:** CIP-012-1
3. **Purpose:** To protect confidentiality and integrity of data transmitted between Control Centers required for reliable operation of the Bulk Electric System (BES).
4. **Applicability:**
   - **4.1. Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
     - **4.1.1. Balancing Authority**
     - **4.1.2. 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.
5. **Effective Date:** See Implementation Plan for CIP-012-1

B. Requirements and Measures

Rationale for Requirements R1 and R2: FERC Order No. 822 directed NERC to develop modifications to the CIP Reliability Standards to require Responsible Entities to implement controls to protect communication links and sensitive Bulk Electric System (BES) data communicated between BES Control Centers. Reliability Standard CIP-012-1 responds to that directive, requiring Responsible Entities to develop a plan to protect the confidentiality and integrity of sensitive data while being transmitted between Control Centers. Responsible Entities use various means to communicate information between

Control Centers. The plan for protecting these communications is required for all impact levels due to the inter-dependency of multiple impact levels.

The type of data in scope of CIP-012-1 is data used for Operational Planning Analyses, Real-time Assessments, and Real-time monitoring. The terms Operational Planning Analyses, Real-time Assessments, and Real-time used are defined in the Glossary of Terms Used in NERC Reliability Standards and used in TOP-003 and IRO-010, among other Reliability Standards.

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 geographically 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.

R1. The Responsible Entity shall develop one or more documented plan(s) to mitigate the risk of the unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessments, and Real-time monitoring while being transmitted between Control Centers. This excludes oral communications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. Risk mitigation shall be accomplished by one or more of the following actions:

- Physically protecting the communication links transmitting the data;
- Logically protecting the data during transmission; or
- Using an equally effective method to mitigate the risk of unauthorized disclosure or modification of the data.

Note: If the Responsible Entity does not have a Control Center or it does not transmit the type of data specified in Requirement R1 of CIP-012-1 between two Control Centers, the requirements in CIP-012-1 would not apply to that entity.

M1. Evidence may include, but is not limited to, documented plan(s) that meet the security objective of Requirement R1.

R2. The Responsible Entity shall implement the plan(s) specified in Requirement R1, except under CIP Exceptional Circumstances.

M2. Evidence may include, but is not limited to, documentation to demonstrate implementation of methods to mitigate the risk of the unauthorized disclosure or modification of data in Requirement R1.

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 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	N/A	N/A	The Responsible Entity failed to document one or more plan(s) that achieve the security objective to mitigate the risk of unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessments, and Real-time monitoring while being transmitted, excluding oral communication, between Control Centers as specified in Requirement R1.
R2.	N/A	N/A	N/A	The Responsible Entity failed to implement its plan(s) to mitigate the risk of unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessments, and Real-time

				monitoring while being transmitted, excluding oral communication, between Control Centers as specified in Requirement R1, except under CIP Exceptional Circumstances.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to FERC Order No. 822	N/A

Standard Attachments

None.

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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 – Control Center Communication Networks

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 – Control Center Communication Networks

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 twelve (12) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard CIP-012-1 shall become effective on the first day of the first calendar quarter that is twelve (12) 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 Operational Planning Analysis, 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	N/A	N/A	The Responsible Entity failed to document one or more plan(s) that achieve the security objective to mitigate the risk of the unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessments, and Real-time monitoring while being transmitted, excluding oral communication, between Controls Centers as specified in Requirement R1.

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 proposed VSL is binary and is classified as severe. The VSL does 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 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	The VSL is based on a single violation and not cumulative violations.

VRF Justifications for CIP-012-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium was assigned to this requirement. Implementation of required 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 Operational Planning Analysis, 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	Failure to properly implement the cyber security plan would not, under Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state

VRF Justifications for CIP-012-1, Requirement R2	
Proposed VRF	**Medium**
Guideline 4- Consistency with NERC Definitions of VRFs	or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	N/A

VSLs for CIP-012-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Responsible Entity failed to implement its plan to mitigate the risk of the unauthorized disclosure or modification of data used for Operational, Planning Analysis, Real-time Assessments, and Real-time monitoring while being transmitted, excluding oral communication, between Controls Centers as specified in Requirement R1, except under CIP Exceptional Circumstances.

VSL Justifications for CIP-012-1 Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement 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 proposed VSL is binary and is classified as severe. The VSL does 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 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	The VSL is based on a single violation and not cumulative violations.

Project 2016-02 Consideration of Issues and Directives

Federal Energy Regulatory Commission Order No. 822

June 21, 2017

Directives from Order 822		
Paragraph	**Directive Language**	**Consideration of Issue or Directive**
53	53. As discussed in detail below, however, the Commission concludes that modifications to CIP-006-6 to provide controls to protect, at a minimum, communication links and data communicated between bulk electric system Control Centers are necessary in light of the critical role Control Center communications play in maintaining bulk electric system reliability. Therefore, we 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).	The Project 2016-02 Standard Drafting Team (SDT) drafted Reliability Standard CIP-012-1 Requirement R1 to require responsible entities to document one or more plan(s) to mitigate the risk of the unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessments, and Real-time monitoring while being transmitted between Bulk Electric System (BES) Control Centers. Requirement R2 requires implementation of the documented plan(s). Due to the sensitivity of the data being transmitted between the Control Centers, as defined in the NERC Glossary of Terms Used in Reliability Standards, the SDT created the standard and determined that it applies to all impact levels of BES Cyber Systems (i.e., high, medium, or low impact). The SDT has drafted requirements allowing Responsible Entities to apply protection to the links, the data, or both, to satisfy the security objective of the Commission's directive, consistent with the capabilities of the Responsible Entity's

Directives from Order 822		
Paragraph	**Directive Language**	**Consideration of Issue or Directive**
		operational environment. The directive language specifically references CIP-006-6 which pertains to physical security controls. CIP-006-6, Requirement R1, Part 1.10 focuses on protecting the nonprogrammable communication components between Cyber Assets within the same ESP for medium and high impact BES Cyber Systems. The SDT asserts that most of the communications contemplated by the Order are not within the same ESP, and that CIP-006-6, Requirement R1, Part 1.10 would not be the appropriate location for this requirement.
54	54. NERC and other commenters recognize that inter-Control Center communications play a critical role in maintaining bulk electric system reliability by, among other things, helping to maintain situational awareness and reliable bulk electric system operations through timely and accurate communication between Control Centers.[59] We agree with this assessment. In order for certain responsible entities such as reliability coordinators, balancing authorities, and transmission operators to adequately perform their reliability functions, their associated control centers must be capable of receiving and storing a variety of sensitive bulk electric system data from interconnected entities. Accordingly, we find that additional measures to protect both the integrity and availability of sensitive bulk	The SDT agrees that inter-Control Center communications play a critical role in Bulk Electric System reliability. Responsible Entities should therefore apply security measures to mitigate the risk of the unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessments, and Real-time monitoring, which the current CIP Reliability Standards do not address. As such, the SDT has defined requirements that are designed to protect the data while it is being transmitted between inter-entity and intra-entity Control Centers. The SDT has drafted requirements allowing responsible entities to apply protection to the links, the data, or both to satisfy the security objective consistent with the capabilities of the responsible entity's operational environment.

Directives from Order 822		
Paragraph	**Directive Language**	**Consideration of Issue or Directive**
	electric system data are warranted.[60] We also understand that the attributes of the data managed by responsible entities could require different information protection controls. [61] For instance, certain types of reliability data will be sensitive to data manipulation type attacks, while other types of reliability data will be sensitive to eavesdropping type attacks aimed at collecting operational information (such as line and equipment ratings and impedances). NERC should consider the differing attributes of bulk electric system data as it assesses the development of appropriate controls. Footnotes: [59] NERC Comments at 20. [60] Protecting the integrity of bulk electric system data involves maintaining and ensuring the accuracy and consistency of inter-Control Center communications. Protecting the availability of bulk electric system data involves ensuring that required data is available when needed for bulk electric system operations. [61] Moreover, in order for certain responsible entities to adequately perform their Reliability Functions, the associated control centers must be capable of receiving and storing a variety of sensitive data as specified by the	

Directives from Order 822		
Paragraph	**Directive Language**	**Consideration of Issue or Directive**
	IRO and TOP Standards. For instance, pursuant to Reliability Standard TOP-003-3, Requirements R1, R3 and R5, a transmission operator must maintain a documented specification for data and distribute its data specification to entities that have data required by the transmission operator's Operational Planning Analyses, Real-time Monitoring and Real-time Assessments. Entities receiving a data specification must satisfy the obligation of the documented specification.	
55	55. With regard to NERC's development of modifications responsive to our directive, we agree with NERC and other commenters that NERC should have flexibility in the manner in which it addresses the Commission's directive. Likewise, we find reasonable the principles outlined by NERC that protections for communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers: (1) should not have an adverse effect on reliability, including the recognition of instances where the introduction of latency could have negative results; (2) should account for the risk levels of assets and information being protected, and require protections that are commensurate with the risks presented; and (3) should be results-based in order to provide flexibility to	The SDT drafted Reliability Standard CIP-012-1 to establish requirements to mitigate the risk of the unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessments, and Real-time monitoring while being transmitted between Control Centers. The SDT developed objective-based rather than prescriptive requirements. This approach will allow Responsible Entities flexibility in protecting these communications networks and sensitive BES data in a manner suited to each of their respective environments. It will also allow Responsible Entities to implement protection that considers the risks noted by the Commission. The SDT identified a need to mitigate the risk of the unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessment, and Real-time monitoring regardless of asset risk level. The proposal requires protection for all data used for Operational Planning Analysis, Real-time Assessment, and Real-

Directives from Order 822		
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	account for the range of technologies and entities involved in bulk electric system communications.[62] Footnote: [62] See NERC Comments at 20-21.	time monitoring while being transmitted between Control Centers.
56	56. We disagree with the assertion of NIPSCO and G&T Cooperatives that the risk posed by bulk electric system communication networks does not justify the costs of implementing controls. Communications between Control Centers over such networks are fundamental to the operations of the bulk electric system, and the record here does not persuade us that controls for such networks are not available at a reasonable cost (through encryption or otherwise). Nonetheless, we recognize that not all communication network components and data pose the same risk to bulk electric system reliability and may not require the same level of protection. We expect NERC to develop controls that reflect the risk posed by the asset or data being protected, and that can be implemented in a reasonable manner. It is important to recognize that certain entities are already required to exchange necessary real-time and operational planning data through secured networks using a "mutually agreeable security protocol," regardless of the entity's	The SDT noted the FERC reference to additional Reliability Standards and the responsibilities to protect the data in accordance with those standards (TOP-003-3 and IRO-010-2). The SDT interpreted these references as examples of potentially sensitive BES data and chose to base the CIP-012 requirements on the data specifications in these standards. This consolidates scoping and helps ensure that Responsible Entities mitigate the risk of the unauthorized disclosure or modification of Operational Planning Analysis, Real-time Assessment, and Real-time monitoring data, rather than leaving the scoping to individual Responsible Entities. The SDT drafted CIP-012-1 to address confidentiality and integrity of data used for Operational Planning Analysis, Real-time Assessment, and Real-time monitoring. These are accommodated by drafting the requirement to mitigate the risk from unauthorized disclosure or modification. The SDT contends that the availability of this data is already required by the performance obligation of the Operating and Planning Reliability Standards.

Directives from Order 822		
Paragraph	**Directive Language**	**Consideration of Issue or Directive**
	size or impact level.[63] NERC's response to the directives in this Final Rule should identify the scope of sensitive bulk electric system data that must be protected and specify how the confidentiality, integrity, and availability of each type of bulk electric system data should be protected while it is being transmitted or at rest. Footnote: [63] See Reliability Standards TOP-003-3, Requirement R5 and IRO-010-2, Requirement R3.	The SDT drafted CIP-012-1 to address the data while being transmitted. The SDT contends that this data is maintained within BES Cyber Systems, and is afforded the protections of CIP-003 through CIP-011.
58	58. Several commenters sought clarification whether Control Centers owned by multiple registered entities would be included under the Commission's proposal. We clarify that the scope of the directed modifications apply to Control Center communications from facilities at all impact levels, regardless of ownership. The directed modification should encompass communication links and data for intra-Control Center and inter-Control Center communications.	The SDT created the standard and determined that it applies to all impact levels of BES Cyber Systems (i.e., high, medium, or low impact), regardless of ownership. The SDT defined requirements that are designed to mitigate the risk of the unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessment, and Real-time monitoring while being transmitted between inter-entity and intra-entity BES Control Centers.
62	62. Several commenters addressed encryption and latency. Based on the record in this proceeding, it is reasonable to conclude that any lag in communication speed resulting from implementation of protections should only be measureable on the order of	The SDT developed objective-based rather than prescriptive requirements. This approach will allow Responsible Entities flexibility in mitigating the risk of the unauthorized disclosure or modification of data used for Operational Planning Analysis,

Directives from Order 822		
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	milliseconds and, therefore, will not adversely impact Control Center communications. Several commenters raise possible technical implementation difficulties with integrating encryption technologies into their current communications networks. Such technical issues should be considered by the standard drafting team when developing modifications in response to this directive, and may be resolved, e.g., by making certain aspects of the revised CIP Standards eligible for Technical Feasibility Exceptions.	Real-time Assessments, and Real-time monitoring in a manner suited to each of their respective environments. It will also allow Responsible Entities to implement protection that considers the risks noted by the Commission.

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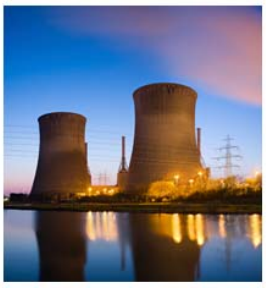
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT Reliability Standards Development Plan

2018-2020

June 2017

RELIABILITY | ACCOUNTABILITY



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Background

The 2017–2019 Reliability Standards Development Plan (RSDP) continued progress toward NERC's goal to develop a stable set of clear, concise, technically sound, and results-based NERC Reliability Standards and to retire requirements that do little to promote reliability. The 2017-2019 RSDP specifically highlighted the importance of the Integration of Variable Generation Task Force and Essential Reliability Services Working Group (ERSWG) recommendations and called for continued communication with the Reliability Issues Steering Committee (RISC) on emerging risks. The 2017-2019 RSDP also indicated that most of the work in the next three years would focus on Periodic Reviews and recognized there may be new or emerging risks identified that would generate new standards development projects. The addition of the Standards Grading Metric in 2016 informs the Periodic Reviews as to the quality and content of the standards.[1]

The 2017-2019 RSDP also recognized the importance of addressing subsequent directives from applicable regulatory authorities including the Federal Energy Regulatory Commission (FERC), Standard Authorization Requests (SARs), and the value of enhanced communication through industry feedback loops. It also stressed that Periodic Reviews and standards development activities would occur at a measured pace, compared to the level of activity and pace of standards development during previous years, and they will be aligned with strategic considerations of reviewing standard families that are interrelated.[2]

As described herein, the 2018-2020 RSDP builds upon the goals of the 2017-2019 RSDP, adding an additional objective of enhanced consideration of cost effectiveness in standards development.

Pursuant to section 310 of the NERC Rules of Procedure, NERC is required to develop and provide to applicable governmental authorities an annual RSDP for Reliability Standards development. Each annual RSDP must include a progress report comparing results achieved to the prior year's RSDP. NERC is required to consider the comments and priorities of the applicable governmental authorities in developing and updating the annual RSDP. NERC also provides the RSDP to the NERC Standards Committee (SC) for review and posts the RSDP for industry comment.

[1] The Periodic Review standing review team will grade the standards. The team includes representatives from NERC, the Regional Entities, and the NERC technical committees. Grading occurs prior to conducting the Periodic Review.

[2] In some cases, a narrower review of a standard will likely be appropriate. For example, there are not necessarily other interrelated standards with FAC-003.

Executive Summary

The 2018–2020 RSDP recognizes the diligent work of the last few years in transforming the body of NERC Reliability Standards into a mature state while shifting its focus to Periodic Reviews, FERC directives, emerging risks, SARs, and the standards grading initiative. The 2018-2020 RSDP also contemplates that the work of the various NERC technical committees and working groups thereunder, may result in one or more SARs and subsequent standards projects.

As with the 2017-2019 RSDP, Periodic Reviews will occur at a measured pace compared to the level of activity and pace of standards development during recent years. Additionally, Periodic Reviews will be aligned with strategic considerations of reviewing standard families that are interrelated. The Standards Grading Metric and "Final Grades for Standards Graded in 2017" (Attachment 1) help to inform the Periodic Reviews as to the quality and content of the standards.[3]

The 2018-2020 RSDP also includes plans for completing the Periodic Reviews initiated in 2016 and 2017, and for commencing additional Periodic Reviews in 2018.

While most of the work in the next three years will focus on Periodic Reviews, there may be new or emerging risks identified that would generate new standards development projects. NERC will continue to seek input and recommendations from the RISC with regard to emerging or potential risks to BES reliability that may require revisions to existing standards or new standards development. To help determine impact of potential risk to BES reliability, NERC will use various feedback mechanisms, including but not limited to, feedback from the Compliance Monitoring and Enforcement Program, RISC profiles, Events Analysis and Compliance violation statistics, as well as any published "Lessons Learned." The Regional Entities also have feedback mechanisms in place to solicit comments from industry and to help identify approaches to meet concerns and provide input to the standards. Standards input will continue to be coordinated with the North American Energy Standards Board as appropriate.

NERC is committed to enhancing and refining cost effectiveness considerations in the standards development process during the 2018-2020 period. For example, during 2016 and 2017, NERC conducted two cost effectiveness pilots.[4] NERC continues to develop and implement its cost effectiveness process, which has been implemented more broadly in standards development and will continue to evolve during this work plan period. Cost effectiveness questions are also part of the Periodic Reviews and SAR process. NERC will continue to look for ways to enhance or refine the review and implementation of cost effectiveness during the standards development process in a way that is productive and does not unduely burden the industry for data and input.

This 2018-2020 RSDP provides insight into standards development activities anticipated at the time of publication, so that stakeholders may make available appropriate resources to accomplish these standards development objectives. Additional activities such as Requests for Interpretation and Regional Variance development may impact the plan. In order to help the industry understand resource requirements for each project, the RSDP now shows time frames and anticipated resources for each project under development.

[3] The Periodic Review standing review team grades the standards prior to conducting Periodic Reviews. The team includes representatives from NERC, the Regions, and NERC technical committees. If there is a recommended change in the standard due to Periodic Review recommendations and subject to the standards development process, the Periodic Review standing review team will re-grade the standard with the revised language.

[4] Information on NERC's cost effectiveness initiative can be found at: http://www.nerc.com/pa/Stand/Pages/CostEffectivenessPilot.aspx.

2017 Progress Report

Pursuant to section 310 of the NERC Rules of Procedure, NERC offers the following progress report on Reliability Standards development in 2017.

FERC Directives

As of June 14, 2017, there are 29 outstanding FERC directives. Additionally, FERC has issued directives pertaining to issues outside of NERC standards. These additional directives are being addressed by the NERC technical committees and other NERC departments (e.g., topics related to reliability assessment, performance analysis, etc.), which are not reflected in this total.

Projects Completed in 2017

The 2017–2019 RSDP identified nine projects initiated in 2017 or continued from 2016. All of the projects listed therein have been completed in 2016 or are planned to be completed in 2017 except for Project 2013-03 Geomagnetic Disturbance Mitigation, Project 2015-09 Establish and Communicate System Operating Limits, Project 2015-10 Single Points of Failure, and Project 2016-02 Modifications to CIP Standards. Additional project information is available on the NERC website on the Standards page.[5]

The following projects have been or are planned to be completed in 2017 (actual and anticipated NERC Board of Trustees (Board) adoption dates are noted)**:**

Projects from the 2017-2019 RSDP

1. Project 2015-08 Emergency Operations – EOP-004, EOP-005, EOP-006, EOP-008 (adopted by the Board in February 2017)
2. Project 2016-01 Modifications to TOP and IRO Standards – TOP-001, IRO-002 (adopted by the Board in February 2017)
3. Project 2016-03 Cyber Security Supply Chain Management – CIP-013-1 (Board adoption expected in August 2017)
4. Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards - PER-001, PER-003, and PER-004
5. Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards - VAR-001 and VAR-002

[5] As of the date of publication, the subject web page resides at http://www.nerc.com/pa/Stand/Pages/default.aspx.

2018 Projects

Projects Continuing from 2017 into 2018

In determining high, medium, or low priority to designate projects as listed in this RSDP, the following factors were taken into consideration.

1. Outstanding regulatory directives with filing deadlines (High Priority)
2. RISC category rankings of high impact with consideration of probability of occurrence (High or Medium Priority)
3. Potential reliability risk from stakeholders provided through feedback mechanism (High, Medium or Low Priority, based on the risk)
4. Outstanding regulatory directives without regulatory deadlines or "soft directives" such as considerations (High or Medium Priority)
5. Outstanding requirements that are known candidates for retirement (Medium or Low Priority)
6. Any known adverse content and quality assessments (likely Low Priority, as any reliability gaps identified have already been addressed)

High Priority

- Project 2013-03 Geomagnetic Disturbance Mitigation - TPL-007-2 (drafting estimated to be completed by April 1, 2018[6] requiring approximately 11 industry subject matter experts for approximately 120 work hours[7] each for the remaining part of this project)
    - FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 2018
- Project 2016-02: Modifications to CIP Standards (drafting estimated to be completed by May 1, 2018 requiring approximately 10 industry subject matter experts or approximately 75 work hours each for the remaining part of this project)

Medium Priority

- Project 2015-09 Establish and Communicate System Operating Limits- FAC-010, FAC-011, FAC-014 (drafting estimated to be completed by April 1, 2018 requiring approximately 10 industry subject matter experts or approximately 100 work hours each for the remaining part of this project)
- Project 2015-10 Single Points of Failure - TPL-001 (drafting estimated to be completed by April 1, 2018 requiring approximately 10 industry subject matter experts or approximately 60 work hours each for the remaining part of this project)
- 2016-04 Modifications to PRC-025-1 (drafting estimated to be completed by April 1, 2018 requiring approximately 6 industry subject matter experts for approximately 60 work hours each for the remaining part of this project)

Low Priority

- Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards - PER-001, PER-003, and PER-004 (drafting estimated to be completed by April 1, 2018

[6] The "estimated drafting completed by" date is NERC's estimate of the final ballot date.
[7] The "work hours" estimates apply to 2018 only.

requiring approximately 10 industry subject matter experts for approximately 40 work hours each for the remaining part of this project)

- Project 2017-03 FAC-008 Periodic Review (drafting estimated to be completed by August 1, 2018 requiring approximately 10 industry subject matter experts for approximately 100 work hours each for the remaining part of this project)
- Project 2017-04 Periodic Review of Interchange Scheduling and Coodination Standards - INT-004, INT-006, INT-009 and INT-010 (drafting estimated to be completed by August 1, 2018 requiring approximately 10 industry subject matter experts for approximately 80 work hours each for the remaining part of this project)
- Project 2017-05 Periodic Review of NUC-001-3 (drafting estimated to be completed by May 1, 2018 requiring approximately eight industry subject matter experts for approximately 60 work hours each for the remaining part of this project)

Projects Commencing in 2018

At least two Periodic Reviews should commence in 2018.

The following 31 standards will be eligible for periodic review in 2018:

BAL-005-02b	IRO-006-5	MOD-008-1	MOD-030-3	PRC-019-2
BAL-006-2	IRO-008-2	MOD-020-0	MOD-031-2	TOP-002-4
CIP-014-2	IRO-010-2	MOD-025-2	MOD-033-1	TOP-003-3
FAC-003-4	IRO-014-3	MOD-026-1	PER-001-1.1(ii)	
FAC-010-3	IRO-017-1	MOD-027-1	PRC-002-2	
FAC-013-2	MOD-001-1a	MOD-028-2	PRC-015-1	
IRO-001-4	MOD-004-1	MOD-029-2a	PRC-016-1	

Additionally, SARs, emerging risks to the Bulk Power System, and FERC regulatory directives that may occur subsequent to publishing this RSDP may prompt additional projects in 2018.

Standards Grading Metrics

The NERC SC endorsed a grading system for standards as a metric on March 9, 2016. The grading is conducted by the Periodic Review Standing Review Team (PRSRT) as set forth in the Periodic Review process. The PRSRT is comprised of the following:

- SRT chair: SC chair or (or SC chair delegate)
- Operating Committee (OC) chair (or OC chair delegate)
- Planning Committee (PC) chair (or PC chair delegate)
- NERC staff
- Representation from the Regional Entities

The grading metrics include possible scores of 0-3 for quality and 0-13 for content. The set of standards chosen each year for grading, according to the criteria in the above section, will be reviewed and their grading will be used to prioritize and determine the sequence they should enter into the Periodic Review process. At least one industry comment period will take place to allow industry to comment on the grading performed by the PRSRT. The grades, based on the PRSRT and any industry input will be finalized, appended to the RSDP, and used to complete the prioritization each year.

Attachment 1

Final Grades for Standards Graded in 2017 (placeholder)

Standard and Requirement	Content Average	Quality Average

NERC
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Standards Announcement

Project 2017-03 FAC-008-3 Periodic Review

Periodic Review Team Nomination Period Open through 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.

The time commitment for this project is expected to be two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the team sets forth. Team members may also have side projects, either individually or by sub-group, to present for discussion and review. Lastly, an important component of the team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful ballot.

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 Senior Standards Developer, Al McMeekin (via email) or at (404) 446-9675.

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2017 Standard Grading Summary

Standard | Requirement		OC	PC	RE	NERC	Avg.	Max Dif	OC	PC	RE	NERC	Avg.	Max Dif
		Content Questions						Quality Questions					
BAL-003-1.1	R1	3	3	2	3	2.75	**1**	13	13	13	13	13	**0**
BAL-003-1.1	R2	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
BAL-003-1.1	R3	3	2	3	3	2.75	**1**	13	13	13	13	13	**0**
BAL-003-1.1	R4	3	2	3	3	2.75	**1**	13	13	13	13	13	**0**
COM-001-2.1	R1	3	2	3	3	2.75	**1**	13	11	13	13	12.5	**2**
COM-001-2.1	R2	3	2	3	3	2.75	**1**	13	12	13	13	12.75	**1**
COM-001-2.1	R3	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R4	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R5	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R6	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R7	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R8	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R9	3	3	3	3	3.00	**0**	11	13	13	13	12.5	**2**
COM-001-2.1	R10	3	3	3	3	3.00	**0**	12	13	13	13	12.75	**1**
COM-001-2.1	R11	3	3	2	3	2.75	**1**	13	13	10	13	12.25	**3**
COM-002-4	R1	3	3	2	3	2.75	**1**	11	13	13	13	12.5	**2**
COM-002-4	R2	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-002-4	R3	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-002-4	R4	3	3	3	3	3.00	**0**	13	13	12	13	12.75	**1**
COM-002-4	R5	3	3	3	3	3.00	**0**	12	13	12	13	12.5	**1**
COM-002-4	R6	3	3	3	3	3.00	**0**	12	13	12	13	12.5	**1**
COM-002-4	R7	3	3	3	3	3.00	**0**	12	13	12	13	12.5	**1**
FAC-001-2	R1	3	3	2	3	2.75	**1**	13	10	13	13	12.25	**3**
FAC-001-2	R2	3	3	3	3	3.00	**0**	13	10	13	13	12.25	**3**
FAC-001-2	R3	3	3	3	3	3.00	**0**	13	10	12	13	12	**3**
FAC-001-2	R4	3	3	3	3	3.00	**0**	13	10	11	13	11.75	**3**
FAC-002-2	R1	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
FAC-002-2	R2	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
FAC-002-2	R3	3	2	2	3	2.50	**1**	13	13	12	13	12.75	**1**
FAC-002-2	R4	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
FAC-002-2	R5	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
IRO-009-2	R1	3	3	3	3	3.00	**0**	13	12	13	13	12.75	**1**
IRO-009-2	R2	3	3	3	3	3.00	**0**	13	12	13	13	12.75	**1**
IRO-009-2	R3	3	3	3	3	3.00	**0**	13	12	13	13	12.75	**1**
IRO-009-2	R4	3	3	3	3	3.00	**0**	13	12	13	13	12.75	**1**
MOD-032-1	R1	3	2	1	2	2.00	**2**	13	13	11	13	12.5	**2**
MOD-032-1	R2	3	2	2	2	2.25	**1**	13	13	13	13	13	**0**
MOD-032-1	R3	3	2	2	2	2.25	**1**	13	13	13	13	13	**0**
MOD-032-1	R4	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
TPL-001-4	R1	3	3	3	3	3.00	**0**	13	13	12	13	12.75	**1**
TPL-001-4	R2	3	3	2	3	2.75	**1**	13	13	10	13	12.25	**3**
TPL-001-4	R3	3	2	3	3	2.75	**1**	13	11	10	13	11.75	**3**
TPL-001-4	R4	3	2	3	3	2.75	**1**	13	11	11	13	12	**2**
TPL-001-4	R5	3	3	3	3	3.00	**0**	13	13	11	13	12.5	**2**
TPL-001-4	R6	3	3	3	3	3.00	**0**	13	13	11	13	12.5	**2**
TPL-001-4	R7	3	3	3	3	3.00	**0**	13	13	10	13	12.25	**3**
TPL-001-4	R8	3	3	2	3	2.75	**1**	13	13	11	13	12.5	**2**

Standard Number	Requirement Number	Text of Requirement *(if text is incomplete, please use entire requirement pasted on NERC.com)*	Supports a Reliability Objective (as defined by the Reliability Principles) (Yes or No)	Meets the Paragraph 81 criteria* (Yes or No)	Appropriate as a guide rather than a standard? (Yes or No)	Content Questions from the Standards Independent Experts Report Q1 (Yes or No) Is the content of the requirement technically correct, including identifying who does what and when?	Q2 (Yes or No) Are the correct functional entities identified?	Q3 (Yes or No) Are the appropriate actions, for which there should be accountability, included or is there a gap?	Quality Questions from the Standards Independent Experts Report Q4 (Yes or No) Should the requirement stand alone or, is it or should it be consolidated with other standards?	Q5 (Yes or No) Is it written as a results-based standard (RBS) requirement (states what, not prescriptive, capability) and does it follow the VRS format (e.g., sub-requirement structure)?	Q6 (Yes or No) Is it technologically neutral?	Q7 (Yes or No) Are the expectations for each function clear?	Q8 (Yes or No) Does the requirement align with the purpose?	Q9 (Yes or No) Is it a higher solution than the lowest common denominator?	Q10 (Yes or No) Is it measurable?	Q11 (Yes or No) Does it have a technical basis in engineering and operations?	Q12 (Yes or No) Is it complete and self-contained?	Q13 (Yes or No) Is the language clear and direct, not contain ambiguous or outdated terms?	Q14 (Yes or No) Can it be practically implemented?	Q15 (Yes or No) Does it use consistent terminology?	Q16 (Yes or No) Is the standard used effective in achieving the reliability purpose or objective of the Standard and mitigating the risk to the BES?	Content Score 0-3	Quality Score 0-12	Comment/Rationale
BAL-003-1.1	R1	R1: Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation. The Frequency Response Obligation for a Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. [Risk Factor: High][Time Horizon:Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Balancing Authorities and groups of BAs are the logical place to put this obligation.
BAL-003-1.1	R2	R2: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall maintain a Frequency Bias Setting that is, to the extent practical, equal to Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. [Risk Factor:Medium][Time Horizon: Operations Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	This is the essence of coordinated frequency operations in a multiple BA interconnect.
BAL-003-1.1	R3	R3: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: [Risk Factor: Medium][Time Horizon: Operations Planning] R3.1: Less than zero at all times, and R3.2: Equal to or more negative than its Frequency Response Obligation when frequency varies from 60 Hz by more than +/- 0.036 Hz.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Necessary to identify bounds for variable frequency bias.
BAL-003-1.1	R4	R4: Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, or order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: [Risk Factor: Medium][Time Horizon: Operations Planning] • The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or • The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Technical description of the requirements allowing overlap regulation. This wouldn't be necessary if overlap regulation were not allowed.
COM-001-2.1	R1	R1: Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R1.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R1.2.: Each adjacent Reliability Coordinator within the same Interconnection.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R2	R2: Each Reliability Coordinator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High][Time Horizon: Real-time Operations] R2.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R2.2.: Each adjacent Reliability Coordinator within the same Interconnection.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	I was on this SDT. It does feel very administrative and unduly burdensome as a standard, when a simple guide that says that you ought to back up critical communication systems would be sufficient.
COM-001-2.1	R3	R3: Each Transmission Operator shall have Interpersonal Communication capability with the following entities (unless the Transmission Operator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R3.1.: Its Reliability Coordinator. R3.2.: Each Balancing Authority within its Transmission Operator Area. R3.3.: Each Distribution Provider within its Transmission Operator Area. R3.4.: Each Generator Operator within its Transmission Operator Area. R3.5.: Each adjacent Transmission Operator synchronously connected. R3.6.: Each adjacent Transmission Operator asynchronously connected.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R4	R4: Each Transmission Operator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R4.1.: Its Reliability Coordinator. R4.2.: Each Balancing Authority within its Transmission Operator Area. R4.3.: Each adjacent Transmission Operator synchronously connected. R4.4.: Each adjacent Transmission Operator asynchronously connected.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I was on this SDT. It does feel very administrative and unduly burdensome as a standard, when a simple guide that says that you ought to back up critical communication systems would be sufficient.
COM-001-2.1	R5	R5: Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R5.1.: Its Reliability Coordinator. R5.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R5.3.: Each Distribution Provider within its Balancing Authority Area. R5.4.: Each Generator Operator that operates Facilities within its Balancing Authority Area. R5.5.: Each adjacent Balancing Authority.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R6	R6: Each Balancing Authority shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon:Real-time Operations]. R6.1.: Its Reliability Coordinator. R6.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R6.3.: Each Adjacent Balancing Authority.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I was on this SDT. It does feel very administrative and unduly burdensome as a standard, when a simple guide that says that you ought to back up critical communication systems would be sufficient.
COM-001-2.1	R7	R7: Each Distribution Provider shall have Interpersonal Communication capability with the following entities (unless the Distribution Provider detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]. R7.1.: Its Balancing Authority. R7.2.: Its Transmission Operator.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R8	R8: Each Generator Operator shall have Interpersonal Communication capability with the following entities (unless the Generator Operator detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R8.1.: Its Balancing Authority. R8.2.: Its Transmission Operator.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R9	R9: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations, Same-day Operations]	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	13	This could easily be a guide. The testing of backup communications presumes that the primary communications medius is functional - so I doubt this to be a Medium Risk and it is overly prescriptive when the only point is to make sure your backup comms are functioning.
COM-001-2.1	R10	R10: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	This one is a necessary requirement in a mandatory compliance environment, but the time limits are arbitrary and that creates unnecessary grief. 31 minutes, an hour, both of these could be acceptable equipment outage time limits.
COM-001-2.1	R11	R11: Each Distribution Provider and Generator Operator that detects a failure of its Interpersonal Communication capability shall consult each entity affected by the failure, as identified by the Distribution Provider or Generator Operator, within 60 minutes of the detection of the failure, to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	This could easily be a guide. Just tell them to contact their BA/TOP and works something out as a backup (cell phone or something similar.)
COM-002-4	R1	R1: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall develop documented communications protocols for its operating personnel that issue and receive Operating Instructions. The protocols shall, at a minimum: [Violation Risk Factor: Low][Time Horizon: Long-term Planning] R1.1.: Require its operating personnel that issue oral or oral or written Operating Instruction to use the English language, unless agreed to otherwise. An alternate language may be used for internal operations. R1.2.: Require its operating personnel that issue an oral two-party, person-to-person Operating Instruction to take one of the following actions: • Confirm the receiver's response if the repeated information is correct. • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver. R1.3.: Require its operating personnel that issue oral two-party, person-to-person Operating Instruction to take one of the following actions: • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction. R1.4.: Require its operating personnel that issue a written or oral single-party to multiple-party burst Operating Instruction to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. R1.5.: Specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification. R1.6.: Specify the nomenclature for Transmission interface Elements and Transmission Interface Facilities when issuing an oral or written Operating Instruction.	Yes	No	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	13	This never should have included three part communications in the requirement. The English part is okay. Three part should have been a guide and strongly encouraged. FERC Lowered this requirement during the SDT. What they did not understand is that this is only a problem during some other requirement violation, not at any other time. Publishing a guide and enforcing the other, core reliability requirements with extra emphasis when they are violated in part by communication issues is a better approach. We've elevated mundane speech and consequently deemphasized the important speech.
COM-002-4	R2	R2: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall conduct initial training for each of its operating personnel responsible for the Realtime operation of the interconnected Bulk Electric System on the documented communications protocols developed in Requirement R1 prior to that individual operator issuing an Operating Instruction. [Violation Risk Factor: Low][Time Horizon: Long-term Planning]	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Governs emergencies - okay here.
COM-002-4	R3	R3: Each Distribution Provider and Generator Operator shall conduct initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction to either: [Violation Risk Factor: Low][Time Horizon: Long-term Planning] • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Governs emergencies - okay here.
COM-002-4	R4	R4: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall at least once every twelve (12) calendar months: [Violation Risk Factor:Medium][Time Horizon: Operations Planning] R4.1.: Assess adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, and provide feedback to those operating personnel and take corrective action, as deemed appropriate by the entity, to address deviations from the documented protocols. R4.2.: Assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modify its documented communication protocols, as necessary.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Governs emergencies - okay here.
COM-002-4	R5	R5: Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations] • Confirm the receiver's response if the repeated information is correct (in accordance with Requirement R6). • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	12	Should have been a guide.
COM-002-4	R6	R6: Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that receives an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations] • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	12	Should have been a guide.
COM-002-4	R7	R7: Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues a written or oral single-party to multiple-party burst Operating Instruction during an Emergency shall confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. [Violation Risk Factor:High][Time Horizon: Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	12	Should have been a guide.
FAC-001-2	R1	R1: Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R1.1. generation Facilities; R1.2.: transmission Facilities; and R1.3. end-user Facilities.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-001-2	R2	R2: Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-001-2	R3	R3: Each Transmission Owner shall address the following items in its Facility interconnection requirements: [Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning] R3.1.: Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s). R3.2.: Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-001-2	R4	R4: Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: [Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning] R4.1.: Procedures for coordinated studies of new interconnections and their impacts on affected system(s). R4.2.: Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R1	R1: Each Transmission Planner and each Planning Coordinator shall study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) materially modifying existing interconnections of transmission Facilities or electricity end-user Facilities. The following shall be studied: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R1.1.: The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s); R1.2.: Adherence to applicable NERC Reliability Standards, regional and Transmission Owner planning criteria, and Facility interconnection requirements; R1.3.: Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and R1.4.: Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R2	R2: Each Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.2-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R3	R3: Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity seeking to interconnect new transmission Facilities or electricity end-user Facilities, or to materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R4	R4: Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or materially modified interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R5	R5: Each applicable Generator Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
IRO-009-2	R1	R1: For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including load shedding): [Violation Risk Factor: Medium] [Time Horizon: Operations Planning or Same Day Operations] R1.1.: That can be implemented in time to prevent the identified IROL exceedance. R1.2.: To mitigate the magnitude and duration of an IROL exceedance such that the IROL exceedance is relieved within the IROL's Tv.	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
IRO-009-2	R2	R2: Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
IRO-009-2	R3	R3: Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's Tv, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [ViolationRisk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
IRO-009-2	R4	R4: Each Reliability Coordinator shall operate to the most limiting IROL and Tv in instances where there is a difference in the values identified by different Reliability Coordinators for the responsible for that Facility (or group of Facilities). [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
MOD-032-1	R1	R1:Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] R1.1.: The data listed in Attachment 1; R1.2.: Specifications of the following items consistent with procedures for building the interconnection-wide case(s): R1.2.1.: Data format; R1.2.2.: Level of detail to which equipment shall be modeled; R1.2.3.: Case types or scenarios to be modeled; and R1.2.4.: A schedule for submission of data at least once every 13 calendar months. R1.3.: Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
MOD-032-1	R2	R2: Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider in the Planning Coordinator's area, and each of 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. [Violation Risk Factor: Medium] [Time Horizon:Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
MOD-032-1	R3	R3: Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R3.1.: Provide either updated data or an explanation with a technical basis for maintaining the current data. R3.2.: Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
MOD-032-1	R4	R4: Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the interconnection-wide case(s) that includes the Planning Coordinator's planning area. [Violation Risk Factor: Medium] [Timehorizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	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 the data used for the Planning Assessment, the MOD-032 and MOD-033 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R1.1.: System models shall represent: R1.1.1.: Existing Facilities R1.1.2.: Known outage(s) of generation or Transmission 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.: Resource (supply or demand side) required for Load	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R2	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 analysis, short-circuit analysis, and Stability analysis. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R2.1.: 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: R2.1.1.: System peak Load for either Year One or year two, and for year five. R2.1.2.: System Off-Peak Load for one of the five years. R2.1.3.: P1 events in Table 1, with no Contingency modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled. R2.1.4.: 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: • Generator output level and 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. R2.2.5.: When an entity's bank equipment regularly counts near 0 in the unavailability of	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R3	and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizon portions of the steady-state, Part 3.1.1 and 3.1.2. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R3.1.: 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. R3.2.: Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.3. R3.3.: Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall: R3.3.1.: 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: R3.3.2.1.: 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 voltage ride-through capability. Include in the assessment any assumptions made. R3.3.2.2.: Tripping of Transmission elements where relay loadability limits are exceeded. R3.3.2.: Simulate the expected automatic operation of existing and planned device 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. R3.4.: Document assumptions, and summarize steady-state, dynamics, and short-circuit analysis results 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. R3.4.1.: The Planning Coordinator and Transmission Planner shall coordinate with adjacent	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R4	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] R4.1.: 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. R4.1.1.: For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism. R4.1.2.: 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. R4.1.3.: For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner. R4.2.: Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.3. R4.3.: Contingency analyses

TPL-001-4	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. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13			
TPL-001-4	R7	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]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13			
TPL-001-4	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 need and that submits a written request for the information within 30 days of such a request. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R8.1. 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.	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13			

Standard Number	Requirement Number	Text of Requirement *(if text is incomplete, please cut entire requirement pasted on NERC.com)*	Supports a Reliability Objective (as defined by the Reliability Principles)	Meets the Paragraph 81 criteria? (Yes or No)	Appropriate as a guide rather than a standard? (Yes or No)	Content Questions from the Standards Independent Experts Report Q1 (Yes or No) Is the content of the requirement technically correct, including identifying who does what and when?	Q2 (Yes or No) Are the correct functional entities identified?	Q3 (Yes or No) Are the appropriate actions, for which there should be accountability, included in them a gap?	Should the requirement stand alone as it is or should it be combined with other standards?	Is it: A) effect vs a multi-tiered standard (R6); requirement (performance, risk (prevention) or capability) and does it follow the NRS format (e.g., sub-requirement structure)?	Is it technologically neutral?	Are the expectations for each function clear?	Does the requirement align with the purpose?	Is it a higher solution than the lowest common denominator?	Is it measurable?	Does it have a technical basis in engineering and operations?	Is it complete and self-contained?	Is the language clear and does not contain ambiguous or outdated terms?	Can it be practically implemented?	Does it use consistent terminology?	Is the Standard cost effective in achieving the reliability purpose? Have you considered the cost and mitigating the risk to the BES?	Content Score 0-3	Quality Score 0-12	Comment/Rationale
BAL-003-1.1	R1	R1: Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. [Risk Factor: High] [Time Horizon Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
BAL-003-1.1	R2	R2: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. [Risk Factor: Medium] [Time Horizon: Operations Planning]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
BAL-003-1.1	R3	R3: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall implement a variable Frequency Bias Setting that is: [Risk Factor: Medium] [Time Horizon: Operations Planning] R3.1: Less than zero at all times, and R3.2: Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	There was a confusion on the interpretation of applicability on Interconnection versus Area
BAL-003-1.1	R4	R4: Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, by one of the following methods: either: [Risk Factor: Medium] [Time Horizon: Operations Planning] • The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO; or • The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	There was a confusion on the interpretation of applicability on Interconnection versus Area
COM-001-2.1	R1	R1: Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R1.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R1.2.: Each adjacent Reliability Coordinator within the same Interconnection.	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	2	11	ICC is too broadly interpreted, guidance should show acceptable examples, not generically applied
COM-001-2.1	R2	R2: Each Reliability Coordinator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R2.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R2.2.: Each adjacent Reliability Coordinator within the same Interconnection.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	12	RCs need to be directed to include communications to other RCs in other Interconnections where appropriate. Single entity RC/Interconnections are proof of this.
COM-001-2.1	R3	R3: Each Transmission Operator shall have Interpersonal Communication capability with the following entities (unless the Transmission Operator detects a failure of its Interpersonal Communication capability in which case Requirement R13 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R3.1.: Its Reliability Coordinator. R3.2.: Each Balancing Authority within its Transmission Operator Area. R3.3.: Each Distribution Provider within its Transmission Operator Area. R3.4.: Each Generator Operator within its Transmission Operator Area. R3.5.: Each adjacent Transmission Operator synchronously connected. R3.6.: Each adjacent Transmission Operator asynchronously connected.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R4	R4: Each Transmission Operator that designates an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R4.1.: Each Balancing Authority within its Transmission Operator Area. R4.2.: Each adjacent Transmission Operator synchronously connected. R4.3.: Each adjacent Transmission Operator asynchronously connected.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R5	R5: Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R5.1.: Its Reliability Coordinator. R5.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R5.3.: Each Distribution Provider within its Balancing Authority Area. R5.4.: Each Generator Operator that operates Facilities within its Balancing Authority Area. R5.5.: Each Adjacent Balancing Authority.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R6	R6: Each Balancing Authority that designates an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R6.1.: Its Reliability Coordinator. R6.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R6.3.: Each Adjacent Balancing Authority.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R7	R7: Each Distribution Provider shall have Interpersonal Communication capability with the following entities (unless the Distribution Provider detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] R7.1.: Its Balancing Authority. R7.2.: Its Transmission Operator.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R8	R8: Each Generator Operator shall have Interpersonal Communication capability with the following entities (unless the Generator Operator detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R8.1.: Its Balancing Authority. R8.2.: Its Transmission Operator.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R9	R9: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations, Same-day Operations]	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R10	R10: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations].	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R11	R11: Each Distribution Provider and Generator Operator that detects a failure of its Interpersonal Communication capability shall consult each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
FAC-002-2	R1	R1: Each Transmission Planner and each Planning Coordinator shall study the reliability impacts of new interconnections, new generation Facilities, and materially modified existing and (2) materially modifying existing interconnections of generators, transmission, and electricity end-user Facilities. The following shall be studied: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R1.1.: The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s). R1.2.: Adherence to applicable NERC Reliability Standards, regional and Transmission Planner criteria, and Facility Interconnection Requirements resulting from; R1.3.: Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and R1.4.: Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	The applicability is not clear as it may require entities to duplicate work of one another. Suggest - PC in coordination with the TP, instead of saying PC and TP. Also, when the requirement specifies TP or PC, what if the other doesn't get told.
FAC-002-2	R2	R2: Each Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	
FAC-002-2	R3	R3: Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity, seeking to interconnect new transmission Facilities, or to materially modify existing or materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	
FAC-002-2	R4	R4: Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or materially modified interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	
FAC-002-2	R5	R5: Each applicable Generator Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	
IRO-009-2	R1	R1: For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including load shedding). [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Real-time Operations] R1.1.: That can be implemented in time to prevent the identified IROL exceedance. R1.2.: To mitigate the magnitude and duration of an IROL exceedance such that the IROL exceedance is relieved within the IROL's Tv.	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Where appropriate, this standard should be looked at to consolidate with IRO-008
IRO-009-2	R2	R2: Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Where appropriate, this standard should be looked at to consolidate with IRO-009
IRO-009-2	R3	R3: Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's Tv, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Where appropriate, this standard should be looked at to consolidate with IRO-010
IRO-009-2	R4	R4: Each Reliability Coordinator shall operate to the most limiting IROL and Tv in instances where there is a difference in an IROL or its Tv between Reliability Coordinators that are responsible for that Facility (or group of Facilities). [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Where appropriate, this standard should be looked at to consolidate with IRO-011
MOD-032-1	R1	R1.Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short-circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]: R1.1.: The data listed in Attachment 1. R1.2.: Specifications of the following items consistent with procedures for building the Interconnection-wide case(s): R1.2.1.: Data format; R1.2.2.: Level of detail to which equipment shall be modeled; R1.2.3.: Case types or scenarios to be modeled; and R1.2.4.: A schedule for submission of data at least once every 13 calendar months. R1.3.: Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	ERO needs to be dropped from the applicability of the standard
MOD-032-1	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. [Violation Risk Factor: Medium] [Time Horizon:Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	ERO needs to be dropped from the applicability of the standard
MOD-032-1	R3	R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R3.1.: Provide either updated data or an explanation with a technical basis for maintaining the current data. R3.2.: Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	ERO needs to be dropped from the applicability of the standard

MOD-032-1	R4	R4: Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. [Violation Risk Factor: Medium] [Timeframe: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	ERO needs to be dropped from the applicability of the standard
TPL-001-4	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 required by other Requirements of this standard. The models shall represent System conditions. This establishes Category P0 as the normal System condition in Table 1 [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R1.1.: System models shall represent: R1.1.1.: Existing Facilities R1.1.2.: Known outage(s) of generation or Transmission 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	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R2	Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R1, Part 2.6), document assumptions, and document summarized results of the steady state analysis, short circuit analysis, and Stability analyses. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R2.1.: 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 address the following periods: R2.1.1.: System peak Load for either Year One or year two, and for year five. R2.1.2.: System Off-Peak Load for one of the five years. R2.1.3.: 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. R2.1.4.: For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, the Planning Assessment shall model and document the conditions and system topology 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 reasonable change in System response: • Real and reactive forecasted Load. • Expected transfers. • Expected in-service status of Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.•ICControllable Loads and Demand Side Management. • Duration or timing of known Transmission outages. R2.1.5.: When an entity's spare-equipment strategy could result in the unavailability of	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R3	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] R3.1.: 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 3.3. R3.2.: 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. R3.3.: Contingency analysis for Requirement R3, Parts 3.1 & 3.2 shall: R3.3.1.: 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 analysis shall include the impact of subsequent: R3.3.1.1.: 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. R3.3.1.2.: Tripping of Transmission elements where relay loadability limits are exceeded. R3.3.2.: 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, static var devices, and switched shunts. [Violation Risk Factor: Medium] R3.4.: 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. R3.4.1.: The Planning Coordinator and Transmission Planner shall coordinate with adjacent	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	no	2	11	The question here is in the conduct of all extreme cases being measured. Is it all necessary?
TPL-001-4	R4	Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analysis 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] R4.1.: 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 4.3. R4.1.1.: For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism. R4.1.2.: 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 element other than the generating unit and its directly connected facilities. R4.1.3.: For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner. R4.2.: 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. R4.3.: Contingency analysis for Requirement R4, Parts 4.1 and 4.2 shall: R4.3.1.: 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 analysis shall include the impact of subsequent: R4.3.1.1.: Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a fault where high speed reclosing is utilized. R4.3.1.2.: 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.	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	no	2	11	The question here is in the conduct of all extreme cases being measured. Is it all necessary?
TPL-001-4	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. These criteria shall include, but are not limited to, 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]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	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. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R7	R7: Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identifyeach entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: Low] [Time Horizon:Long-term Planning]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	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 information within 30 days of such a request. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R8.1.: 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.	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	

| Number | Title | Name | Yes/No/Abstain | Yes/No/Abstain | Yes/No/Abstain

Standard Number	Requirement Number	Text of Requirement *If text is incomplete, please cut entire requirement posted on NERC.com*	Supports a Reliability Objective (as defined by the Reliability Principles) (Yes or No)	Meets the Paragraph 81 criteria? (Yes or No)	Appropriate as a guide rather than a standard? (Yes or No)	Content Questions from the Standards Independent Experts Report Q1 (Yes or No) Is the content of the requirement technically correct, including identifying who does what and when?	Q2 (Yes or No) Are the correct functional entities identified?	Q3 (Yes or No) Are the appropriate actions, for which there should be accountability, included or is there a gap?	Quality Questions from the Standards Independent Experts Report Q4 (Yes or No) Should the requirement stand alone or is it more appropriate with other standards?	Q5 (Yes or No) Is it worthy of a metric (i.e. level of performance, risk prevention) or capability and does it follow the 'KBL for'or e.g., 'sub-requirement structure'?	Q6 (Yes or No) Is it technologically neutral?	Q7 (Yes or No) Are the expectations for each function clear?	Q8 (Yes or No) Does the requirement align with the purpose?	Q9 (Yes or No) Is it a higher solution than the lowest common denominator?	Q10 (Yes or No) Is it measurable?	Q11 (Yes or No) Does it have a technical basis in engineering and operations?	Q12 (Yes or No) Is it complete and self-contained?	Q12A (Yes or No) Is the language clear and does not contain ambiguous or outdated terms ?	Q13 (Yes or No) Can it be practically implemented?	Q14 (Yes or No) Does it use consistent terminology?	Q15 (Yes or No) Is the Standard cost effective in achieving the reliability purpose or mitigating the risk identified and mitigating the risk to the BES?	Content Score 0-3	Quality Score 0-13	Comment/Rationale
BAL-003-1.1	R1	R1: Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is maintained by each FRSG and Balancing Authority to support Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. [Risk Factor: High][Time Horizon: Real-time Operations].	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
BAL-003-1.1	R2	R2: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, or a documented local FRO annually filed with the ERO, on or before the date specified by the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. [Risk Factor:Medium][Time Horizon: Operations Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
BAL-003-1.1	R3	R3: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall implement a variable Frequency Bias Setting that is: [Risk Factor: Medium] [Time Horizon: Operations Planning] R3.1: Less than zero at all times, and R3.2: Equal to or more negative than its Frequency Response Obligation when frequency varies from 60 Hz by more than +/- 0.036 Hz.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
BAL-003-1.1	R4	R4: Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: [Risk Factor: Medium][Time Horizon: Operations Planning] • The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or • The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R1	R1: Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R1.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R1.2.: Each adjacent Reliability Coordinator within the same Interconnection.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R2	R2: Each Reliability Coordinator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High][Time Horizon: Real-time Operations] R2.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R2.2.: Each adjacent Reliability Coordinator within the same Interconnection.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R3	R3: Each Transmission Operator shall have Interpersonal Communication capability with the following entities (unless the Transmission Operator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R3.1.: Its Reliability Coordinator. R3.2.: Each Balancing Authority within its Transmission Operator Area. R3.3.: Each Distribution Provider within its Transmission Operator Area. R3.4.: Each Generator Operator within its Transmission Operator Area. R3.5.: Each adjacent Transmission Operator synchronously connected. R3.6.: Each adjacent Transmission Operator asynchronously connected.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R4	R4: Each Transmission Operator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R4.1.: Its Reliability Coordinator. R4.2.: Each Balancing Authority within its Transmission Operator Area. R4.3.: Each adjacent Transmission Operator synchronously connected. R4.4.: Each adjacent Transmission Operator asynchronously connected.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R5	R5: Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R5.1.: Its Reliability Coordinator. R5.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R5.3.: Each Distribution Provider within its Balancing Authority Area. R5.4.: Each Generator Operator that operates Facilities within its Balancing Authority Area. R5.5.: Each Adjacent Balancing Authority.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R6	R6: Each Balancing Authority shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R6.1.: Its Reliability Coordinator. R6.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R6.3.: Each Adjacent Balancing Authority.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R7	R7: Each Distribution Provider shall have Interpersonal Communication capability with the following entities (unless the Distribution Provider detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] R7.1.: Its Balancing Authority. R7.2.: Its Transmission Operator.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R8	R8: Each Generator Operator shall have Interpersonal Communication capability with the following entities (unless the Generator Operator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R8.1.: Its Balancing Authority. R8.2.: Its Transmission Operator.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R9	R9: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Interpersonal Communication capability required by R1, R2, R3, R4, R5, R6, R7, and R8. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations, Same-day Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R10	R10: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	For consistency with VAR-002, should notification be made immediately of any failure of communication lasting greater than 30 minutes?
COM-001-2.1	R11	R11: Each Distribution Provider and Generator Operator that detects a failure of its Interpersonal Communication capability shall consult each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	For consistency with VAR-002, should notification be made immediately of any failure of communication lasting greater than 30 minutes?
COM-002-4	R1	R1: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall have communications (voice and data, redundant and diverse) facilities to issue and receive Operating Instructions. The protocols shall, at a minimum: [Violation Risk Factor: Low][Time Horizon: Long-term Planning] R1.1.: Require its operating personnel that issue and receive oral or written Operating Instruction to use the English language, unless agreed to otherwise. An alternate language may be used for internal operations. R1.2.: Require its operating personnel that issue an oral two-party, person-to-person Operating Instruction to take one of the following actions: • Confirm the receiver's response if the repeated information is correct. • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver. • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver. R1.3.: Require its operating personnel that receive an oral two-party, person-to-person Operating Instruction to take one of the following actions: • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction. R1.4.: Require its operating personnel that issue a written or oral single-party to multiple-party burst Operating Instruction to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. R1.5.: Specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification. R1.6.: Specify the facilities where the Transmission Interface Elements and Transmission Interface Facilities which issuing an oral or written Operating Instruction	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-002-4	R2	R2: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall conduct initial training for each of its operating personnel responsible for the Realtime operation of the interconnected Bulk Electric System on the documented communications protocols developed in Requirement R1 prior to the individual operator's being assigned operating duties. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does verifying initial training for well-seasoned personnel create challenges?
COM-002-4	R3	R3: Each Distribution Provider and Generator Operator shall conduct initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction to either: [Violation Risk Factor: Low][Time Horizon: Long-term Planning] • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does verifying initial training for well-seasoned personnel create challenges?
COM-002-4	R4	R4: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall at least once every twelve (12) calendar months: [Violation Risk Factor:Medium][Time Horizon:Operations Planning] R4.1.: Assess adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, provide feedback to those operating personnel and take corrective action, as deemed appropriate by the entity, to address deviations from the documented protocols. R4.2.: Assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modify its documented communication protocols, as necessary.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-002-4	R5	R5: Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations] • Confirm the receiver's response if the repeated information is correct (in accordance with Requirement R6). • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	
COM-002-4	R6	R6: Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that receives an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations] • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-002-4	R7	R7: Each Balancing Authority, Distribution Provider, and Transmission Operator that issues a written or oral single-party to multiple-party burst Operating Instruction during an Emergency shall confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. [Violation Risk Factor:High][Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	
FAC-001-2	R1	R1: Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R1.1.: Generation Facilities, and R1.2.: transmission Facilities, and R1.3.: end-user Facilities.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-001-2	R2	R2: Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an interconnection agreement or a modification to existing interconnection agreement to a Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-001-2	R3	R3: Each Transmission Owner shall address the following items in its Facility interconnection requirements: [Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning] R3.1.: Procedures for coordinated joint studies of new or materially modified existing interconnections and their impacts on affected system(s). R3.2.: Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	
FAC-001-2	R4	R4: Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: [Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning] R4.1.: Procedures for coordinated joint studies of new interconnections and their impacts on affected system(s). R4.2.: Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R1	R1: Each Transmission Planner and each Planning Coordinator shall study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) materially modifying existing interconnections of generation, transmission, or electricity end-user Facilities. The following shall be studied: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R1.1.: The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s). R1.2.: Adherence to applicable NERC Reliability Standards, regional and Transmission Planner criteria, and applicable Nuclear Plant Interface Requirements (NPIRs). R1.3.: Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and R1.4.: Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R2	R2: Each Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R3	R3: Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity seeking to interconnect new transmission Facilities or electricity end-user Facilities, or to materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R4	R4: Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or materially modified interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R5	R5: Each applicable Generator Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
IRO-009-2	R1	R1: For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including Emergency procedures): [Violation Risk Factor: High] [Time Horizon: Operations Planning or Same-Day Operations] R1.1.: That can be implemented in time to prevent the identified IROL exceedance. R1.2.: To mitigate the magnitude and duration of an IROL exceedance such that the IROL exceedance is relieved within the IROL's T_V.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does it adequately cover the right entities; e.g., should it include Adjacent RC, and perhaps Transmission Operator?
IRO-009-2	R2	R2: Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does it adequately cover the right entities; e.g., should it include Adjacent RC, and perhaps Transmission Operator?
IRO-009-2	R3	R3: Each Reliability Coordinator shall 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. [ViolationRisk Factor: High] [Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does it adequately cover the right entities; e.g., should it include Adjacent RC, and perhaps Transmission Operator?
IRO-009-2	R4	R4: Each Reliability Coordinator shall operate to the most limiting IROL and T_V in instances where there is a difference in an IROL or its T_V between Reliability Coordinators that are responsible for that Facility (or group of Facilities). [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does it adequately cover the right entities; e.g., should it include Adjacent RC, and perhaps Transmission Operator?
MOD-032-1	R1	R1:Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R1.1.: The data listed in Attachment 1. R1.2.: Specifications of the following items consistent with procedures for building the interconnection-wide case(s): R1.2.1: Data formats; R1.2.2.: Level of detail to which equipment shall be modeled; R1.2.3.: Case types or scenarios to be modeled; and R1.2.4.: A schedule for submission of data at least once every 13 calendar months. R1.3.: Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.	YES	YES	NO	YES	No	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	2	11	LSE is no longer in Registry.
MOD-032-1	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. [Violation Risk Factor: Medium] [Time Horizon:Long-term Planning]	YES	YES	NO	YES	NO	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	2	11	LSE is no longer in Registry.
MOD-032-1	R3	R3: Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall provide to the notifying Planning Coordinator or Transmission Planner as follows: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R3.1.: Provide either updated data or an explanation with a technical basis for maintaining the current data. R3.2.: Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.	YES	YES	NO	YES	NO	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	2	11	LSE is no longer in Registry.
MOD-032-1	R4	R4: Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the interconnection-wide case(s) that includes the Planning Coordinator's planning area. [Violation Risk Factor: Medium] [TimeHorizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
TPL-001-4	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. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R1.1.: Models shall represent: R1.1.1.: Existing Facilities R1.1.2.: Known outage(s) of generation or Transmission 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	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Should models capture adjacent Transmission Planner area?
TPL-001-4	R2	R2: Each Transmission Planner and Planning Coordinator shall perform an annual Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, as allowed in Requirement R2, Part 2.4; document assumptions and document summarized results of the steady-state analyses, short circuit analysis, and Stability analyses. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R2.1.: 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 2.4. Qualifying studies need to include the following conditions: R2.1.1.: System Peak Load for one of the five years and for year five. R2.1.2.: System Off-Peak Load for one of the five years. R2.1.3.: P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.2.2, under those System peak or Off-Peak conditions when known outages are scheduled. R2.1.4.: 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 base assumptions used in the models listed in Requirement R1. 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 demonstrates 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.•Uncontrollable Loads and generation. • Duration or timing of known Transmission outages. R2.1.5.: When an entity's spare equipment strategy could result in the unavailability of	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Should adjacent system be monitored for reliability issues and model outages in adjacent planning area?
TPL-001-4	R3	R3: 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] R3.1.: 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. R3.2.: 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. R3.3.: Contingency analysis for Requirement R3, Parts 3.1 & 3.2 shall: R3.3.1.: 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 analysis shall include the impact of subsequent: R3.3.2.: Tripping of Transmission elements where relay loadability limits are exceeded. R3.3.2: 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, such as generator voltage regulators, load tap changing transformers, and switched capacitors and inductors. R3.4.: 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.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Should contingencies from the adjacent planning models be included?
TPL-001-4	R4	R4: 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] R4.1.: 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. R4.1.1.: For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism. R4.1.2.: 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. R4.1.3.: For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner. R4.2.: 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. R4.3.: Contingency analysis for Requirement R4, Parts 4.5 and 4.2 shall : R4.3.1.: 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 analysis shall include the impact of subsequent: R4.3.1.1.: Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a fault where high speed reclosing is utilized. R4.3.2.2.: Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator voltage ride through capability. Include in the assessment any assumptions made.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Should contingencies from the adjacent planning models be included?
TPL-001-4	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. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	Should most limiting criteria be included? Reference for this would be Requirement R1, Part 1.1.2 of FAC-001-2.

TPL-001-4	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. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES		YES		NO		YES		YES		YES		YES		YES		YES		YES		YES		YES		YES	3		Should most limiting criteria be included? Reference for this would be Requirement R1, Part 1.1.2 of FAC-002-2.
TPL-001-4	R7	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]	YES		YES		NO		YES		YES		YES		YES		YES		YES		YES		YES		YES		YES	3		Should most limiting criteria be included? Reference for this would be Requirement R1, Part 1.1.2 of FAC-002-2.
TPL-001-4	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 the receiving entity shall have a reliability need if it cannot duplicate, using publicly available models, the results of the Planning Assessment. The receiving entity may submit a written request for the information within 30 days of such a request. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R8.1: 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.	YES		YES		NO		YES		YES		YES		YES		YES		YES		YES		YES		YES		YES	3		Should most limiting criteria be included? Reference for this would be Requirement R1, Part 1.1.2 of FAC-002-2. Should third-party impact be identified and followed by coordination of study results?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards

Periodic Review Team Nomination Period Open through May 15, 2017

Now Available

Nominations are being sought for periodic review team members through **8 p.m. Eastern, Monday, May 15, 2017**.

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

Previous drafting or periodic review team experience is beneficial, but not required. See the project page and unofficial nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the team July 2017. Nominees will be notified shortly after they have been appointed**.**

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

North American Electric Reliability Corporation
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Atlanta, GA 30326
404-446-2560 | www.nerc.com

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
1	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 82.61% Approval: 80.73%			
2	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 83.01% Approval: 79.89%			
3	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 88.83% Approval: 95.43%			
4	Project 2008-07	Interpretation Request - EOP-002 - Brookfield_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 89.67% Approval: 76.47%			
5	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_rc	Recirculation Ballot	6/13/2008	6/22/2008	Quorum: 89.36% Approval: 95.21%			
6	Project 2008-09	Request for Interpretation - EOP-001-0 - RECM_in	Initial Ballot	6/19/2008	7/2/2008	Quorum: 84.82% Approval: 85.79%			
7	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.57% Approval: 79.13%			
8	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.98% Approval: 78.31%			
9	Pre-2006	IROL Standard - IRO-010_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.71% Approval: 88.40%			
10	Pre-2006	IROL Standard - IRO-009_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.63% Approval: 89.44%			
11	Pre-2006	IROL Standard - IRO-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.67% Approval: 91.71%			
12	Project 2006-07	ATC et al Standard - MOD-030_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.37% Approval: 56.56%			
13	Project 2006-07	ATC et al Standard - MOD-029_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.67% Approval: 92.62%			
14	Project 2006-07	ATC et al Standard - MOD-028_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.64% Approval: 79.47%			
15	Project 2006-07	ATC et al Standard - MOD-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.27% Approval: 80.44%			
16	Project 2006-07	ATC et al Standard - MOD-001_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.02% Approval: 75.97%			
17	Project 2008-10	Request for Interpretation - CIP-006-1 - Progress Energy_in	Initial Ballot	8/7/2008	8/16/2008	Quorum: 88.18% Approval: 21.52%			
18	Pre-2006	IROL Standard - IRO-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.72% Approval: 89.49%			
19	Pre-2006	IROL Standard - IRO-009_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.68% Approval: 86.53%			
20	Pre-2006	IROL Standard - IRO-010_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.75% Approval: 85.95%			
21	Project 2006-07	ATC et al Standards - MOD-001_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 94.87% Approval: 76.83%			
22	Project 2006-07	ATC et al Standard - MOD-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.15% Approval: 81.49%			
23	Project 2006-07	ATC et al Standard - MOD-028_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.54% Approval: 79.34%			
24	Project 2006-07	ATC et al Standard - MOD-029_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.56% Approval: 92.24%			
25	Project 2006-07	ATC et al Standard - MOD-030_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.24% Approval: 74.26%			
26	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_in	Initial Ballot	9/9/2008	9/17/2008	Quorum: 85.78% Approval: 90.37%			
27	Project 2006-07	ATC et al Standard - MOD-004_in	Initial Ballot	9/11/2008	9/21/2008	Quorum: 79.26% Approval: 66.29%			
28	Project 2007-14	Permanent Changes to CI Timing Tables_in	Initial Ballot	9/12/2008	9/22/2008	Quorum: 79.74% Approval: 100.00%			
29	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rb	Re-ballot	10/6/2008	10/24/2008	Quorum: 82.61% Approval: 74.67%			
30	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_in	Initial Ballot	10/21/2008	10/30/2008	Quorum: 83.33% Approval: 96.94%			
31	Project 2006-01	Project 2006-01 - PER-005-1_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 90.13% Approval: 82.47%			
32	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 89.13% Approval: 70.01%			
33	Project 2006-07	ATC et al Standard - MOD-004_rc	Recirculation Ballot	10/28/2008	11/6/2008	Quorum: 91.49% Approval: 83.71%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
34	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_in	Initial Ballot	12/1/2008	12/10/2008	Quorum: 83.77% Approval: 86.51%			
35	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 93.04% Approval: 57.37%			
36	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 87.62% Approval: 97.47%			
37	Project 2006-01	Project 2006-01 - PER-005-1_rc	Recirculation Ballot	12/12/2008	12/22/2008	Quorum: 91.48% Approval: 80.63%			
38	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.15% Approval: 97.39%			
39	Project 2008-16	TOP-004-2 VSL Revisions_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.20% Approval: 93.93%			
40	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_rc	Recirculation Ballot	1/6/2009	1/15/2009	Quorum: 91.47% Approval: 91.21%			
41	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_rc	Recirculation Ballot	1/20/2009	1/29/2009	Quorum: 85.86% Approval: 86.39%			
42	Project 2008-16	TOP-004-2 VSL Revisions_rc	Recirculation Ballot	1/28/2009	2/6/2009	Quorum: 92.59% Approval: 96.06%			
43	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_rc	Recirculation Ballot	2/6/2009	2/16/2009	Quorum: 93.81% Approval: 99.12%			
44	Project 2008-09	Interpretation Request - EOP-001 - R1 - RECM_in	Initial Ballot	2/27/2009	3/9/2009	Quorum: 89.67% Approval: 89.03%			
45	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_in	Initial Ballot	3/19/2009	3/30/2009	Quorum: 89.78% Approval: 92.62%			
46	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_in	Initial Ballot	4/1/2009	4/10/2009	Quorum: 91.90% Approval: 84.06%			
47	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_in	Initial Ballot	4/8/2009	4/17/2009	Quorum: 92.70% Approval: 92.71%			
48	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_in	Initial Ballot	4/14/2009	4/23/2009	Quorum: 89.81% Approval: 76.63%			
49	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 94.37% Approval: 88.32%			
50	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 95.56% Approval: 92.81%			
51	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_in	Initial Ballot	4/22/2009	5/1/2009	Quorum: 88.64% Approval: 84.77%			
52	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_rc	Recirculation Ballot	5/6/2009	5/18/2009	Quorum: 92.08% Approval: 75.39%			
53	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_in	initial Ballot	5/25/2009	6/4/2009	Quorum: 85.13% Approval: 82.10%			
54	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_rc	Recirculation Ballot	5/26/2009	6/5/2009	Quorum: 90.45% Approval: 85.76%			
55	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_in	Initial Ballot	6/1/2009	6/11/2009	Quorum: 87.10% Approval: 95.71%			
56	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_in	Initial Ballot	6/12/2009	6/22/2009	Quorum: 81.72% Approval: 94.09%			
57	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_in	Initial Ballot	6/15/2009	6/24/2009	Quorum: 87.23% Approval: 83.94%			
58	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_rc	Recirculation Ballot	7/7/2009	7/16/2009	Quorum: 92.77% Approval: 84.96%			
59	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_rc	Recirculation Ballot	7/8/2009	7/17/2009	Quorum: 90.26% Approval: 82.25%			
60	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_rc	Recirculation Ballot	7/10/2009	7/20/2009	Quorum: 87.10% Approval: 96.94%			
61	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 95.26% Approval: 95.62%			
62	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 91.24% Approval: 98.85%			
63	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 90.46%			
64	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.40% Approval: 89.14%			
65	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.32% Approval: 88.26%			
66	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.16% Approval: 90.15%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
67	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 88.63%			
68	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.64% Approval: 87.63%			
69	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.50% Approval: 85.78%			
70	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.28% Approval: 89.56%			
71	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 87.98% Approval: 87.31%			
72	Project 2009-17	Project 2009-17 Interpretation - Y-W Electric and Tri-State - PRC-004-1 and PRC-005-1_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 90.32% Approval: 62.15%			
73	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rb	Re-ballot	7/27/2009	8/14/2009	Quorum: 84.65% Approval: 74.79%			
74	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_in	Initial Ballot	8/6/2009	8/17/2009	Quorum: 84.68% Approval: 68.92%			
75	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 89.28%			
76	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.04% Approval: 89.41%			
77	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.41% Approval: 84.64%			
78	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.67% Approval: 88.04%			
79	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.17% Approval: 88.73%			
80	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 90.77%			
81	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.31% Approval: 86.93%			
82	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.11% Approval: 88.26%			
83	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.70% Approval: 85.80%			
84	Order 706-B	Order 706-B Nuclear Implementation Plan_in	Initial Ballot	8/19/2009	8/28/2009	Quorum: 81.96% Approval: 97.37%			
85	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rc	Recirculation Ballot	8/20/2009	8/31/2009	Quorum: 86.96% Approval: 70.85%			
86	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.68% Approval: 80.37%			
87	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.92% Approval: 79.04%			
88	Project 2009-18	Project 2009-18 - Withdraw Three Midwest ISO Waivers_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 85.28% Approval: 99.62%			
89	Order 706-B	Order 706-B Nuclear Implementation Plan_rc	Recirculation Ballot	9/1/2009	9/10/2009	Quorum: 87.11% Approval: 97.18%			
90	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rc	Recirculation Ballot	9/2/2009	9/14/2009	Quorum: 86.31% Approval: 76.09%			
91	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_in	Initial Ballot	9/10/2009	9/21/2009	Quorum: 87.45% Approval: 94.18%			
92	Project 2009-16	Project 2009-16 - Interpretation - WECC - CIP-007-1_in	Initial Ballot	9/9/2009	9/21/2009	Quorum: 85.31% Approval: 100.00%			
93	Project 2006-04	Project 2006-04 - Back-up Facilities - EOP-008-1_in	Initial Ballot	9/16/2009	9/28/2009	Quorum: 82.69% Approval: 72.86%			
94	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_rc	Recirculation Ballot	9/29/2009	10/9/2009	Quorum: 89.92% Approval: 68.31%			
95	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 Revised R1 for Progress Energy	Initial Ballot	9/30/2009	10/12/2009	Quorum: 79.92% Approval: 74.47%			
96	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_rc	Recirculation Ballot	10/16/2009	10/26/2009	Quorum: 86.29% Approval: 83.25%			
97	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_rc	Recirculation Ballot	11/2/2009	11/12/2009	Quorum: 88.70% Approval: 94.24%			
98	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 2_in	Initial Ballot	11/5/2009	11/16/2009	Quorum: 85.97% Approval: 98.07%			
99	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_in	Initial Ballot	11/20/2009	11/30/2009	Quorum: 89.58% Approval: 88.07%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
100	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 1) in	Initial Ballot	11/19/2009	12/7/2009	Quorum: 85.83% Approval: 58.91%			
101	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc. in	Initial Ballot	11/20/2009	12/7/2009	Quorum: 87.11% Approval: 93.40%			
102	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response rc	Recirculation Ballot	12/3/2009	12/14/2009	Quorum: 93.33% Approval: 85.55%			
103	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers in	Initial Ballot	12/1/2009	12/14/2009	Quorum: 86.13% Approval: 72.11%			
104	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1 rc	Recirculation Ballot	12/11/2009	12/23/2009	Quorum: 90.08% Approval: 78.77%			
105	Project 2009-24	Project 2009-24 - Interpretation - FMPA - EOP-005-1 in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 87.68% Approval: 17.79%			
106	Project 2009-25	Project 2009-25 - Interpretation - BPA - BAL-001-01.a and BAL-002-0 in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 88.00% Approval: 34.28%			
107	Project 2009-26	Project 2009-26 - Interpretation - WECC - CIP-004-1 in	Initial Ballot	1/6/2010	1/19/2010	Quorum: 84.21% Approval: 42.24%			
108	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Initial Ballot	1/12/2010	1/22/2010	Quorum: 89.16% Approval: 75.16%			
109	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 84.98% Approval: 90.82%			
110	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 87.36% Approval: 91.79%			
111	Project 2009-29	Project 2009-29 - Interpretation - TOP-002-2a for FMPP in	Initial Ballot	2/11/2010	2/22/2010	Quorum: 84.34% Approval: 84.56%			
112	Project 2009-19	Project 2009-19 - Interpretation - BAL-002-0 Northwest Power Pool RSG in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.83% Approval: 48.60%			
113	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc. rc	Recirculation Ballot	2/16/2010	2/26/2010	Quorum: 92.44% Approval: 91.90%			
114	Project 2009-30	Project 2009-30 - Interpretation - PRC-001-1 for WPSC in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.51% Approval: 48.74%			
115	Project 2006-02	Project 2006-02 - Assess Transmission Future Needs - TPL-001-1 in	Initial Ballot	2/19/2010	3/1/2010	Quorum: 91.38% Approval: 35.36%			
116	Project 2009-31	Project 2009-31 - Interpretation - TOP-001-1 for FMPP in	Initial Ballot	3/3/2010	3/16/2010	Quorum: 88.24% Approval: 98.27%			
117	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Recirculation Ballot	3/8/2010	3/18/2010	Quorum: 93.71% Approval: 78.15%			
118	Project 2009-32	Project 2009-32 - Interpretation - EOP-003-1 for FMPP rb	Re-ballot	3/10/2010	3/31/2010	Quorum: 91.37% Approval: 77.66%			
119	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers (Revision 1) in	Initial Ballot	3/29/2010	4/8/2010	Quorum: 88.52% Approval: 63.43%			
120	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3 in	Initial Ballot	4/15/2010	4/26/2010	Quorum: 81.97% Approval: 98.64%			
121	SPM	Standards Process Manual Revisions in	Initial Ballot	4/19/2010	4/29/2010	Quorum: 87.82% Approval: 80.48%			
122	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2) in	Initial Ballot	4/28/2010	5/10/2010	Quorum: 83.15% Approval: 74.55%			
123	SPM	Standards Process Manual Revisions rc	Recirculation Ballot	4/30/2010	5/10/2010	Quorum: 93.73% Approval: 86.69%			
124	Project 2010-11	Project 2010-11 SAR for TPL Table 1 Order in	Initial Ballot	5/17/2010	5/27/2010	Quorum: 84.41% Approval: 63.75%			
125	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3 in	Initial Ballot	5/19/2010	6/1/2010	Quorum: 84.83% Approval: 90.83%			
126	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3 rc	Recirculation Ballot	6/22/2010	7/2/2010	Quorum: 89.10% Approval: 87.24%			
127	Project 2006-04	Project 2006-04 - Backup Facilities - Revision 1 in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 89.05% Approval: 79.45%			
128	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 87.04% Approval: 84.98%			
129	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Initial Ballot	7/7/2010	7/17/2010	Quorum: 86.94% Approval: 43.13%			
130	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Initial Ballot	7/8/2010	7/17/2010	Quorum:91.12 % Approval: 22.91%			
131	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	7/8/2010	7/17/2010	Quorum: 86.00% Approval: 28.00%			
132	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: Protection System definition	Initial Ballot	7/8/2010	7/17/2010	Quorum: 87.85% Approval: 39.35%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
133	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Initial Ballot	7/9/2010	7/19/2010	Quorum: 86.18% Approval: 65.93%			
134	Project 2006-04	Prokect 2006-04 - Backup Facilities - Revision 1_rc	Recirculation Ballot	7/16/2010	7/26/2010	Quorum: 93.43% Approval: 85.22%			
135	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	7/23/2010	8/2/2010	Quorum: 94.70% Approval: 58.61%			
136	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	7/24/2010	8/3/2010	Quorum: 92.99% Approval: 49.61%			
137	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_rc	Recirculation Ballot	8/20/2010	8/30/2010	Quorum: 88.26% Approval: 93.93%			
138	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Initial Ballot	9/14/2010	9/24/2010	Quorum: 92.73% Approval: 79.17%			
139	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3	Initial Ballot	9/17/2010	9/27/2010	Quorum: 96.46% Approval: 21.77%			
140	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	9/24/2010	10/4/2010	Quorum: 85.71% Approval: 81.72%			
141	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	10/2/2010	10/14/2010	Quorum: 84.11% Approval: 84.52%			
142	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_rc	Recirculation Ballot	10/4/2010	10/14/2010	Quorum: 88.11% Approval: 99.14%			
143	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_rc	Recirculation Ballot	10/5/2010	10/15/2010	Quorum: 92.19% Approval: 94.78%			
144	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_rc	Recirculation Ballot	10/6/2010	10/16/2010	Quorum: 91.21% Approval: 93.44%			
145	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Recirculation Ballot	10/18/2010	10/28/2010	Quorum: 89.84% Approval: 84.67%			
146	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 93.66% Approval: 43.33%			
147	Project 2010-10	Project 2010-10 FAC-013-2 Planning Transfer Capability_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 88.54% Approval: 39.85%			
148	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_in	Initial Ballot	10/28/2010	11/7/2010	Quorum: 81.61% Approval: 93.72%			
149	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Recirculation Ballot	11/1/2010	11/11/2010	Quorum: 89.41% Approval: 86.83%			
150	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_rc	Recirculation Ballot	11/9/2010	11/13/2010	Quorum: 87.00% Approval: 92.88%			
151	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_rc	Recirculation Ballot	11/19/2010	12/3/2010	Quorum: 87.81% Approval: 82.41%			
152	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_in	Initial Ballot	12/1/2010	12/10/2010	Quorum: 87.07% Approval: 77.06%			
153	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-3	Initial Ballot	12/2/2010	12/11/2010	Quorum: 84.46% Approval: 42.89%			
154	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Recirculation Ballot	12/2/2010	12/13/2010	Quorum: 95.50% Approval: 86.91%			
155	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Initial Ballot	12/7/2010	12/16/2010	Quorum: 88.00% Approval: 51.51%			
156	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Successive Ballot	12/10/2010	12/20/2010	Quorum: 79.88% Approval: 44.65%			
157	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	12/10/2010	12/20/2010	Quorum: 78.00% Approval: 53.00%			
158	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_rc	Recirculation Ballot	12/20/2010	12/30/2010	Quorum: 90.49% Approval: 80.56%			
159	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_in	Recirculation Ballot	12/27/2010	1/5/2011	Quorum: 90.42% Approval: 83.33%			
160	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 22.09%	Oppose 12/16/11		
161	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 33.49%	Oppose 12/16/11		
162	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 26.82%	Oppose 12/16/11		
163	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 28.04%	Oppose 12/16/11		
164	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.60%	Oppose 12/16/11		
165	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 24.15%	Oppose 12/16/11		

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166	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 94.02% Approval: 34.30%	Oppose 12/16/11		
167	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 27.28%	Oppose 12/16/11		
168	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 26.61%	Oppose 12/16/11		
169	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.88%	Oppose 12/16/11		
170	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.15% Approval: 42.06%	Oppose 12/16/11		
171	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.56% Approval: 25.34%	Oppose 12/16/11		
172	Project 2010-10	Project 2010-10: FAC Order 729_in	Initial Ballot	12/30/2010	1/8/2011	Quorum: 83.23% Approval: 58.16%			
173	Project 2010-10	Project 2010-10: FAC Order 729_rc	Recirculation Ballot	1/14/2011	1/23/2011	Quorum: 86.65% Approval: 68.98%			
174	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_rc	Recirculation Ballot	1/26/2011	2/5/2011	Quorum: 93.29% Approval: 86.79%	Support 1/5/11		
175	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Successive Ballot	1/24/2011	2/14/2011	Quorum: 83.95% Approval: 65.71%	Support 2/11/11		
176	Project 2007-23	Project 2007-23 - Violation Severity Levels	Non-binding Poll	2/9/2011	2/22/2011	Quorum: 78.00% Approval: 72.00%	Support 10/28/10		
177	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Successive Ballot	2/18/2011	2/28/2011	Quorum: 79.28% Approval: 79.34%	Support 2/22/11		
178	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Recirculation Ballot	2/24/2011	3/6/2011	Quorum: 87.35% Approval: 68.83%	Support 2/11/11		
179	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Initial Ballot	2/25/2011	3/7/2011	Quorum: 87.10% Approval: 49.54%	Support 3/2/11		
180	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-4	Successive Ballot	4/19/2011	4/28/2011	Quorum: 79.66% Approval: 38.00%	Oppose 4/19/11		
181	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Initial Ballot	4/21/2011	5/2/2011	Quorum: 86.01% Approval: 48.74%	Abstain 4/26/11		
182	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Non-binding Poll	4/21/2011	5/2/2011	Quorum: 75.58% Approval: 73.00%			
183	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Successive Ballot	5/3/2011	5/12/2011	Quorum: 78.33% Approval: 67.00%	No Recommendation		
184	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	5/3/2011	5/12/2011	Quorum: 75.00% Approval: 66.00%			
185	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Recirculation Ballot	5/12/2011	5/23/2011	Quorum: 91.25% Approval: 78.92%	Support 5/12/11		
186	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Successive Ballot	5/18/2011	5/31/2011	Quorum: 92.07% Approval: 73.99%			
187	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Non-binding Poll	5/18/2011	5/31/2011	Quorum: 86.79% Approval: 71.9%			
188	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Initial Ballot	5/31/2011	6/9/2011	Quorum: 88.47% Approval: 48.64%	Oppose 5/31/11		
189	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Non-binding Poll	5/31/2011	6/9/2011	Quorum: 84.18% Approval: 41.00%			
190	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Recirculation Ballot	6/20/2011	6/30/2011	Quorum: 82.97% Approval: 64.76%	Support 6/28/11		
191	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Non-binding Poll	6/20/2011	6/30/2011	Quorum: 52.63% Approval: 60.00%			
192	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	Recirculation Ballot	7/13/2011	7/22/2011	Quorum: 94.33% Approval: 75.37%			
193	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.99%	Support 7/22/11		
194	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 75.17%	Support 7/22/11		
195	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.27%	Support 7/22/11		
196	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 93.00%			
197	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.66% Approval: 93.00%			
198	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 89.00%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
199	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.25% Approval: 46.53%	No Consensus 7/28/11		
200	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.75% Approval: 56.00%			
201	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.82% Approval: 18.23%	No Consensus 7/28/11		
202	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.35% Approval: 20.79%			
203	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Initial Ballot	9/19/2011	9/29/2011	Quorum: 84.86% Approval: 61.10%	Support 9/21/11		
204	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	9/19/2011	9/29/2011	Quorum: 83.13% Approval: 68.68%			
205	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Definition of BES	Initial Ballot	9/30/2011	10/10/2011	Quorum: 92.97% Approval: 71.68%	No Consensus 10/3/11		
206	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Detailed Information to Support BES Exceptions Request	Initial Ballot	9/30/2011	10/10/2011	Quorum: 89.53% Approval: 64.03%	No Consensus 10/7/111		
207	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Recirculation Ballot	10/4/2011	10/13/2011	Quorum: 87.17% Approval: 86.25%	Support 2/22/11		
208	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Initial Ballot	11/7/2011	11/16/2011	Quorum: 88.05% Approval: 85.53%	Support 11/8/11		
209	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Initial Ballot	11/8/2011	11/17/2011	Quorum: 91.20% Approval: 95.05%	Support 11/8/11		
210	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Initial Ballot	11/9/2011	11/18/2011	Quorum: 88.22% Approval: 86.94%	Support 11/10/11		
211	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Initial Ballot	11/9/2011	11/18/2011	Quorum: 85.08% Approval: 85.71%	Support 11/10/11		
212	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Initial Ballot	11/9/2011	11/18/2011	Quorum: 84.82% Approval: 85.31%	Support 11/10/11		
213	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-004-2.1	Initial Ballot	11/9/2011	11/18/2011	Quorum: 84.29% Approval: 96.09%	Support 11/10/11		
214	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Successive Ballot	11/11/2011	11/21/2011	Quorum: 83.53% Approval: 95.99%	Support 11/14/11		
215	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System and Implementation Plan	Recirculation Ballot	11/10/2011	11/21/2011	Quorum: 95.92% Approval: 81.32%	Support 10/3/11		
216	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Detailed Information to Support BES Exceptions Request	Recirculation Ballot	11/10/2011	11/21/2011	Quorum: 93.02% Approval: 81.48%	Support 10/3/11		
217	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Initial Ballot	11/30/2011	12/9/2011	Quorum: 93.92% Approval: 30.82%	Oppose 12/5/11		
218	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Non-binding Poll	11/30/2011	12/9/2011	Quorum: 89.49% Approval: 36.00%			
219	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Initial Ballot	12/2/2011	12/12/2011	Quorum: 87.97% Approval: 36.21%	Oppose 12/5/11		
220	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	12/2/2011	12/12/2011	Quorum: 85.28% Approval: 45.00%			
221	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Recirculation Ballot	12/9/2011	12/19/2011	Quorum: 88.02% Approval: 96.04%	Support 11/14/11		
222	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Recirculation Ballot	12/12/2011	12/22/2011	Quorum: 90.10% Approval: 92.49%	Support 11/8/11		
223	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 92.00% Approval: 94.58%	Support 11/8/11		
224	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 88.48% Approval: 90.10%	Support 11/10/11		
225	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 87.17% Approval: 85.38%	Support 11/10/11		
226	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.91% Approval: 85.03%	Support 11/10/11		
227	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-004-2.1a	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.65% Approval: 96.43%	Support 11/10/11		
228	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 59.93%	Oppose 1/9/12		
229	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 77.08 %	Support 1/9/12		
230	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 78.95%	Support 1/9/12		
231	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Non-binding Poll	1/4/2012	1/13/2012	Quorum: 78.27% Approval: 93.00%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
232	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Non-binding Poll	1/9/2012	1/18/2012	Quorum: 76.41% Approval: 71.42%			
233	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 67.61%			
234	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 70.28%			
235	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 54.64%	Oppose 2/7/12		
236	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 82.11% Approval: 80.62%	Support 2/7/12		
237	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 80.21%	Support 2/7/12		
238	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 80.35% Approval: 71.35%			
239	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 80.06% Approval: 90.86%			
240	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 79.77% Approval: 84.69%			
241	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Successive Ballot	3/14/2012	3/23/2012	Quorum: 88.55% Approval: 79.61%	Support 3/16/12		
242	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Initial Ballot	3/14/2012	3/23/2012	Quorum: 89.63% Approval: 94.71%	Support 3/16/12		
243	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR-002 for Constellation	Initial Ballot	3/14/2012	3/23/2012	Quorum: 86.92% Approval: 63.09%	Support 3/16/12		
244	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	3/19/2012	3/29/2012	Quorum: 81.45% Approval: 61.21%			
245	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	3/19/2012	3/29/2012	Quorum: 80.38% Approval: 41.09%			
246	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	3/19/2012	3/29/2012	Quorum: 84.32% Approval: 73.93%	Support 3/19/12		
247	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	3/19/2012	3/29/2012	Quorum: 81.93% Approval: 66.12%			
248	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Successive Ballot	3/30/2012	4/9/2012	Quorum: 80.37% Approval: 85.18%	Support 4/5/12		
249	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Successive Ballot	3/30/2012	4/9/2012	Quorum: 80.10% Approval: 85.01%	Support 4/5/12		
250	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.28% Approval: 41.09%	Oppose 4/16/12		
251	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 36.84%	Oppose 4/16/12		
252	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 48.70%%	Oppose 4/16/12		
253	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.82% Approval: 43.72%			
254	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.04% Approval: 38.56%			
255	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.53% Approval: 46.38%			
256	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1a	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.95% Approval: 92.41%	Support 4/16/12		
257	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28%% Approval: 75.44%			
258	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.02% Approval: 87.22%			
259	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28% Approval: 80.11%			
260	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.21% Approval: 69.84%			
261	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.48% Approval: 67.64%			
262	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 90.96% Approval: 80.08%	Support 3/16/12		
263	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 92.68% Approval: 94.61%	Support 3/16/12		
264	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.72% Approval: 87.34%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
265	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.94% Approval: 87.32%			
266	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1b	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 90.44% Approval: 93.23%			
267	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 76.84%	Abstain 4/19/12		
268	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 88.11%	Support 4/19/12		
269	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 80.79%	Support 4/19/12		
270	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.63% Approval: 37.37%	Abstain 5/17/12		
271	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.45% Approval: 60.55%	Abstain 5/17/12		
272	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.40% Approval: 38.81%	Abstain 5/17/12		
273	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.98% Approval: 55.08%	Abstain 5/17/12		
274	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.22% Approval: 38.50%	Abstain 5/17/12		
275	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 45.78%	Abstain 5/17/12		
276	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.19% Approval: 67.19%	Abstain 5/17/12		
277	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 60.19%	Abstain 5/17/12		
278	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 47.92%	Abstain 5/17/12		
279	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 58.23%	Abstain 5/17/12		
280	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	5/11/2012	5/21/2012	Quorum: 85.12% Approval: 66.23%	Abstain 5/17/12		
281	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	5/11/2012	5/21/2012	Quorum: 84.09% Approval: 47.88%	Abstain 5/17/12		
282	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	5/15/2012	5/24/2012	Quorum: 84.43% Approval: 46.18%			
283	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	5/15/2012	5/24/2012	Quorum: 79.95% Approval: 52.67%			
284	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Initial Ballot	6/11/2012	6/20/2012	Quorum: 84.14% Approval: 21.11%	Oppose 6/13/12		
285	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	6/11/2012	6/20/2012	Quorum: 81.01% Approval: 28.30%			
286	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	6/18/2012	6/27/2012	Quorum: 79.46% Approval: 79.00%			
287	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	6/18/2012	6/27/2012	Quorum: 75.00% Approval: 70.21%			
288	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Successive Ballot	6/18/2012	6/27/2012	Quorum: 85.98% Approval: 68.22%	Support 6/26/12		
289	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Initial Ballot	6/26/2012	7/5/2012	Quorum: 84.24% Approval: 23.82%	Oppose 6/27/12		
290	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	6/26/2012	7/5/2012	Quorum: 82.26% Approval: 25.19%			
291	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.34% Approval: 81.71%			
292	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.04% Approval: 81.72%			
293	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 84.16% Approval: 79.16%			
294	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 83.87% Approval: 86.91%			
295	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	6/27/2012	7/9/2012	Quorum: 75.37% Approval: 72.16%	No Consensus 7/5/12		
296	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	6/27/2012	7/11/2012	Quorum: 75.37% Approval: 73.71%			
297	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Recirculation Ballot	7/18/2012	7/27/2012	Quorum: 90.97% Approval: 69.81%	Support 6/26/12		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
298	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Non-binding Poll	7/18/2012	7/27/2012	Quorum: 81.31% Approval: 60.93%			
299	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Initial Ballot	7/20/2012	7/30/2012	Quorum: 80.39% Approval: 79.28%	Oppose 7/20/12		
300	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Non-binding Poll	7/20/2012	7/30/2012	Quorum: 78.26% Approval: 76.07%			
301	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Initial Ballot	7/24/2012	8/2/2012	Quorum: 83.11% Approval: 54.16%	Oppose 7/20/12		
302	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	8/17/2012	8/27/2012	Quorum: 78.11% Approval: 80.31%	Support 6/22/12		
303	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group	Successive Ballot	8/23/2012	9/4/2012	Quorum: 79.21% Approval: 87.78%	Support 2/22/10		
304	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Initial Ballot	8/29/2012	9/7/2012	Quorum: 86.71% Approval: 37.68%	Support 9/5/12		
305	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	8/29/2012	9/7/2012	Quorum: 84.17% Approval: 37.36%			
306	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Recirculation Ballot	9/6/2012	9/17/2012	Quorum: 80.35% Approval: 75.01%			
307	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols	Successive Ballot	9/11/2012	9/20/2012	Quorum: 77.70% Approval: 50.57%	Support 9/15/12		
308	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	9/11/2012	9/20/2012	Quorum: 84.05% Approval: 54.07%			
309	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Recirculation Ballot	9/12/2012	9/21/2012	Quorum: 85.36% Approval: 87.34%			
310	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	9/18/2012	9/27/2012	Quorum: 78.54% Approval: 63.40%	No Consensus 9/27/12		
311	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	9/18/2012	9/27/2012	Quorum: 78.93% Approval: 71.04%			
312	Project 2009-19	Project 2009-19 - Interpretation of BAL-002-0 NWPP Reserve Sharing Group	Recirculation Ballot	9/28/2012	10/8/2012	Quorum: 85.11% Approval: 90.34%	Support 2/22/10		
313	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 74.85%	Support 10/4/12		
314	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.37% Approval: 89.50%	Support 10/4/12		
315	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 85.58%	Support 10/4/12		
316	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 89.46%	Support 10/4/12		
317	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.11%	Support 10/4/12		
318	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 87.73%	Support 10/4/12		
319	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.74%	Support 10/4/12		
320	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.73%	Support 10/4/12		
321	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 84.60%	Support 10/4/12		
322	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.90%	Support 10/4/12		
323	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	10/1/2012	10/10/2012	Quorum: 78.93% Approval: 94.00%	Support 10/4/12		
324	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	10/1/2012	10/10/2012	Quorum: 79.13% Approval: 91.59%	Support 10/4/12		
325	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Initial Ballot	10/3/2012	10/12/2012	Quorum: 87.50% Approval: 63.25%	Support 10/4/12		
326	VRFs and VSLs	Revisions to Outstanding VRFs and VSLs	Non-binding Poll	10/10/2012	10/23/2012	Quorum: 78.57% Approval: 73.02%			
327	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Recirculation Ballot	10/15/2012	10/24/2012	Quorum: 81.08% Approval: 80.51%	Support 6/22/12		
328	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.55% Approval: 76.50%			
329	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.00% Approval: 57.24%			
330	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Successive Ballot	10/19/2012	10/31/2012	Quorum: 83.61% Approval: 68.31%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
331	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.34% Approval: 71.53%			
332	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.07% Approval: 70.64%			
333	Project 2007-09	Project 2007-09_Generator Verification: MOD-026-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.88% Approval: 77.10%			
334	Project 2007-09	Project 2007-09_Generator Verification: PRC-024-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.40% Approval: 52.72%			
335	Project 2007-09	Project 2007-09_Generator Verification: MOD-025-2	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 77.94% Approval: 64.24%			
336	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.06% Approval: 68.93%			
337	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.51% Approval: 63.63%			
338	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 78.59%	Support 10/4/12		
339	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 92.75%	Support 10/4/12		
340	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 89.73%	Support 10/4/12		
341	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 93.73%	Support 10/4/12		
342	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.53%	Support 10/4/12		
343	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 91.79%	Support 10/4/12		
344	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.47%	Support 10/4/12		
345	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 94.60%	Support 10/4/12		
346	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 88.99%	Support 10/4/12		
347	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.67%	Support 10/4/12		
348	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation Plan	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 94.91%	Support 10/4/12		
349	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 93.23%	Support 10/4/12		
350	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Recirculation Ballot	10/24/2012	11/5/2012	Quorum: 85.14% Approval: 71.39%			
351	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	10/24/2012	11/5/2012	Quorum: 78.93% Approval: 71.04%			
352	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Successive Ballot	10/26/2012	11/6/2012	Quorum: 82.04% Approval: 76.08%	Support 11/5/12		
353	Project 2010-11	Project 2010-11 TPL footnote b Initial Ballot October 2012 in	Initial Ballot	11/9/2012	11/19/2012	Quorum: 80.45% Approval: 56.18%			
354	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Initial Ballot	11/26/2012	12/5/2012	Quorum: 84.81% Approval: 72.57%	Oppose 12/5/12		
355	Project 2013-02	Project 2013-02 - Paragraph 81	Initial Ballot	11/30/2012	12/10/2012	Quorum: 75.77% Approval: 96.45%	Support 12/10/12		
356	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	12/4/2012	12/13/2012	Quorum: 76.78% Approval: 53.57%	No Consensus 12/13/12		
357	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	12/4/2012	12/13/2012	Quorum: 77.22% Approval: 57.91%			
358	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Successive Ballot	12/7/2012	12/17/2012	Quorum: 76.47% Approval: 33.23%	Oppose 12/17/12		
359	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	12/7/2012	12/17/2012	Quorum: 75.58% Approval: 34.80%			
360	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Initial Ballot	12/11/2012	12/20/2012	Quorum: 84.50% Approval: 95.60%	Support 12/19/12		
361	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	12/11/2012	12/20/2012	Quorum: 83.24% Approval: 84.48%	Support 12/19/12		
362	Project 2007-09	Project 2007-09_Generator Verification: MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09_Generator Verification: MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 79.00% Approval: 79.36%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
364	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.68% Approval: 74.27%			
365	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 85.87% Approval: 73.63%			
366	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.19% Approval: 76.53%			
367	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	1/2/2013	1/11/2013	Quorum: 78.16% Approval: 60.31%	Support 1/11/13		
368	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	Non-binding Poll	1/2/2013	1/11/2013	Quorum: 76.38% Approval: 55.68%			
369	Project 2010-11	Project 2010-11 Successive Ballot December 2012_in	Successive Ballot	1/2/2013	1/11/2013	Quorum: 85.47% Approval: 65.77%	No Consensus 1/11/13		
370	Project 2010-14.1	Project 2010-14.1_- Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Initial Ballot	1/4/2013	1/14/2013	Quorum: 83.94% Approval: 21.80%	Oppose 1/11/13		
371	Project 2010-14.1	Project 2010-14.1_- Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Non-binding Poll	1/4/2013	1/14/2013	Quorum: 82.23% Approval: 24.27%			
372	Project 2013-02	Project 2013-02 - Paragraph 81	Recirculation Ballot	1/8/2013	1/17/2013	Quorum: 84.60% Approval: 95.22%	Support 12/10/12		
373	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Recirculation Ballot	1/14/2013	1/23/2013	Quorum: 87.13% Approval: 99.09%	Support 12/19/12		
374	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Recirculation Ballot	1/18/2013	1/28/2013	Quorum: 85.90% Approval: 85.57%	Support 12/19/12		
375	Project 2010-11	Project 2010-11 Recirculation Ballot Jan 2013_in	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 88.55% Approval: 69.63%	No Consensus 1/11/13		
376	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 85.67% Approval: 77.61%	Oppose 12/5/12		
377	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Successive Ballot	2/11/2013	2/20/2013	Quorum: 77.62% Approval: 50.66%	Support 9/5/12		
378	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	2/11/2013	2/20/2013	Quorum: 75.38% Approval: 50.60%			
379	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	2/15/2013	2/28/2013	Quorum: 78.80% Approval: 89.01%	Support 1/11/13		
380	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Non-binding Poll	2/15/2013	2/28/2013	Quorum: 76.38% Approval: 84.24%			
381	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Initial Ballot	3/1/2013	3/11/2013	Quorum: 76.36% Approval: 54.65%			
382	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Successive Ballot	3/13/2013	3/22/2013	Quorum: 77.48% Approval: 84.27%	No Consensus 3/22/13		NPCC to abstain - international nature of the ERO and BPS is not used in Reliability Standards
383	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.58% Approval: 97.18%	Support 3/14/13		
384	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.52% Approval: 98.89%	Support 3/14/13		
385	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Recirculation Ballot	3/18/2013	3/27/2013	Quorum: 81.33% Approval: 89.44%	Support 1/11/13		

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386	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	3/27/2013	4/5/2013	Quorum: 78.39% Approval: 57.50%	No Consensus 4/4/13		The RSC did not reach a full consensus however the majority of respondents had indicated they will support the standard - see comment form for further details. Some believe the standard is not necessary and that existing whitepapers alleviate the need for it. In recognition of the NERC BOT's expectations that COM-003 will be approved by the industry and brought before them for approval, NPCC has voted affirmatively and will supply comments for the record outlining our concerns.
387	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	3/27/2013	4/5/2013	Quorum: 77.97% Approval: 54.28%			
388	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.60% Approval: 66.98%	No Consensus 4/23/13		The majority of NPCC's Balancing Authorities have indicated support for the standard, however NPCC as the Regional Entity has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. To be respectful of the positions of the NPCC BAs who will have to implement this new methodology and the support expressed, NPCC as the Regional Entity will cast an Abstention
389	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 42.75%	Oppose 4/23/13		There is a lack of technical justification for the 500 MW threshold within the standard-NPCC will submit suggested improvements

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
390	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 23.84%	Oppose 4/23/13		Losses of large blocks of load are typically caused by coincident transmission contingencies. Excessive and uninformed adjustments made to generation in order to bring the ACE to zero may well lead to further transmission issues. NPCC will submit suggested improvements
391	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
392	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
393	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
394	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Recirculation Ballot	4/18/2013	4/29/2013	Quorum: 80.70% Approval: 88.15%	No Consensus 3/22/13		
395	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Successive ballot	5/15/2013	5/24/2013	Quorum: 81.25% Approval: 69.23%	Support 5/23/13		The Regional Standard Committee has not expressed any concerns of significance that would warrant a ballot to reject, therefore the RSC recommends a yes vote, "Affirmative", to accept the standard
396	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Non-binding Poll	5/15/2013	5/24/2013	Quorum: 80.17% Approval: 61.11%			
397	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Successive Ballot	6/24/2013	7/3/2013	Quorum: 77.65% Approval: 52.71%			
398	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Non-binding Poll	6/24/2013	7/3/2013	Quorum: 77.12% Approval: 52.48%			
399	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Initial Ballot	7/3/2013	7/12/2013	Quorum: 85.53% Approval: 49.73%			
400	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Successive Ballot	7/10/2013	7/19/2013	Quorum: 76.32% Approval: 58.36%	No Consensus 7/19/13 [Due to the concerns expressed over the potential actions by the NERC BOT and FERC as well as the incremental improvement of the standard over the previous versions, NPCC as the Regional Entity will support the standard and submit comments.]		organizations support the standard as written however some members expressed concern that in order to measure compliance with R1 and R2, the standard will require all Reliability Directives to be investigated to determine if RC approved and documented communication protocols have been violated. Also it was identified that TO, BA communication protocols would have to approved by the RC potentially causing some legal issues if protocols aren't approved and casts question on the enforcement of those protocols. NPCC will be submitting some helpful comments should the standard pass and some non-substantive revision be performed prior to the "final" (previously named recirculation) ballot.
401	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 76.20% Approval: 55.37%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
402	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Successive Ballot	7/10/2013	7/19/2013	Quorum: 85.05% Approval: 72.43%	Support 7/19/13		
403	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 82.51% Approval: 64.59%			
404	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Final Ballot	7/16/2013	7/25/2013	Quorum: 92.31% Approval: 74.54%	No Consensus 7/22/13		The RSC has not reached a full consensus however the majority are in support. Issues outstanding for those not in support are concern over "hitting limits" more frequently and potential issues with BA's potentially "dragging" on the interconnection. NPCC will be voting affirmative on the standard.
405	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Initial Ballot	7/26/2013	8/5/2013	Quorum: 80.05% Approval: 93.00%	Support 8/5/13		
408	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025-1	Final Ballot	8/2/2013	8/12/2013	Quorum: 89.13% Approval: 76.52%	Support 8/12/13		
406	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Initial Ballot	8/2/2013	8/12/2013	Quorum: 76.32% Approval: 62.74%	Support 8/9/13		
407	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	8/2/2013	8/12/2013	Quorum: 75.89% Approval: 55.45%			
409	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Initial Ballot	8/14/2013	8/23/2013	Quorum: 78.33% Approval: 79.42%	Support 8/23/13		
410	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Non-binding Poll	8/14/2013	8/23/2013	Quorum: 77.45% Approval: 81.37%			
411	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Ballot	8/16/2013	8/26/2013	Quorum: 76.14% Approval: 51.10%	No Consensus 8/26/13		NPCC to support with comments
412	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Non-binding Poll	8/16/2013	8/26/2013	Quorum: 75.98% Approval: 53.29%			
413	Project 2010-01	Project 2010-01 - Training - PER-005-2	Ballot	8/23/2013	9/3/2013	Quorum: 75.25% Approval: 34.46%	No Consensus 8/31/13		NPCC to support with comments The most contentious issues raised by RSC members was surrounding the Control Center definition and the potential to vastly expand those needing training subject to the standard and compliance and that there was no need for a standard, rather, the FERC Directives should be addressed through other means.
414	Project 2010-01	Project 2010-01 - Training - PER-005-2	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 80.45% Approval: 34.24%			

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
415	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Ballot	8/23/2013	9/3/2013	Quorum: 81.89% Approval: 43.79%	Oppose 8/31/13		The standard, in the view of the group, has extensive issues including but not limited to, applicability issues, lacks clarity, missing measures, quality, and other substantive issues. NPCC will be submitting detailed comments to address these issues. The RSC does not believe it would be beneficial to support the standard at this point as the next step, if it fails the initial ballot, would still require an additional ballot prior to moving to recirculation due to the substantive changes that are needed for the next revision. NPCC will be submitting helpful comments to NERC and supporting the drafting team effort.
416	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 79.95% Approval: 44.23%			
417	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Ballot	8/26/2013	9/4/2013	Quorum: 82.29% Approval: 41.24%	Support 8/31/13		
418	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 79.66% Approval: 40.00%			
419	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Ballot	8/26/2013	9/4/2013	Quorum: 81.96% Approval: 55.76%	Support 8/31/13		
420	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 80.35% Approval: 58.97%			
421	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	8/26/2013	9/4/2013	Quorum: 78.68% Approval: 66.11%	Support 8/31/13		
426	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Final Ballot	9/4/2013	9/13/2013	Quorum: 85.93% Approval: 90.83%	Support 8/5/13		
422	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Ballot	9/6/2013	9/16/2013	Quorum: 76.15% Approval: 58.23%	No Consensus 9/12/13		
423	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Non-binding Poll	9/6/2013	9/16/2013	Quorum: 75.69% Approval: 59.66%			
424	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Final Ballot	9/11/2013	9/20/2013	Quorum: 91.64% Approval: 98.61%	Support 3/14/13		
425	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Final Ballot	9/11/2013	9/20/2013	Quorum: 90.98% Approval: 98.92%	Support 3/14/13		
427	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Additional Ballot	10/9/2013	10/21/2013	Quorum: 77.58% Approval: 88.75%	Support 10/16/13		
428	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	10/9/2013	10/21/2013	Quorum: 75.89% Approval: 90.04%			
429	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Final Ballot	10/16/2013	10/25/2013	Quorum: 85.71% Approval: 85.38%			
430	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	10/18/2013	10/29/2013	Quorum: 75.83% Approval: 72.55%	Support 10/21/13		
431	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Final Ballot	10/25/2013	11/4/2013	Quorum: 86.90% Approval: 91.95%			
432	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	10/25/2013	11/7/2013	Quorum: 76.67% Approval: 58.24%	No Consensus 11/1/13		
433	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	11/1/2013	11/12/2013	Quorum: 76.23% Approval: 56.48%	Support 11/11/13		

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434	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Initial Ballot	11/4/2013	11/13/2013	Quorum: 76.12% Approval: 67.35%	Support 11/5/13		
435	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-006-4	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 75.58%	Support 11/5/13		
436	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-009-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 68.40%	Support 11/5/13		
437	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 58.03%	Support 11/5/13		
438	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-011-1	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.52% Approval: 71.35%	Support 11/5/13		
439	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Initial Ballot	11/4/2013	11/15/2013	Quorum: 76.42% Approval: 77.82%	Support 11/5/13		
440	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Final Ballot	11/8/2013	11/18/2013	Quorum: 81.68% Approval: 74.34%	Support 10/21/13		
441	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Additional Ballot	11/8/2013	11/20/2013	Quorum: 81.69% Approval: 82.97%	No Consensus 8/26/13		
442	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.05% Approval: 73.46%	Support 8/31/13		
443	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.84% Approval: 69.42%	Support 8/31/13		
444	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	11/13/2013	11/22/2013	Quorum: 80.54% Approval: 57.59%	Support 8/31/13		
445	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Additional Ballot	11/15/2013	11/25/2013	Quorum: 80.81% Approval: 69.43%			
446	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	11/15/2013	11/25/2013	Quorum: 81.06% Approval: 66.09%			
447	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2	Additional Ballot	12/2/2013	12/12/2013	Quorum: 75.29% Approval: 64.24%	No Consensus 12/9/13	Affirmative	
448	Project 2007-11	Project 2007-11 Disturbance Monitoring - PRC-002-2	Initial Ballot	12/6/2013	12/16/2013	Quorum: 82.25% Approval: 43.29%	No Consensus 12/15/13	Affirmative	Highlights of comments received expressed: • Agreement with the methodology to determine BES locations for which data had to be captured • Use of the term "locations" • DDR for Flowgates, IROLs • Clarification needed for some data that is to be captured • Editorial suggestions
449	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Final Ballot	12/6/2013	12/16/2013	Quorum: 87.53% Approval: 77.49%	Support 8/31/13	Affirmative	
450	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-006-4	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 80.77%	Support 11/5/13	Affirmative	
451	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-009-2	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 72.86%	Support 11/5/13	Affirmative	
452	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-011-1	Final Ballot	12/10/2013	12/20/2013	Quorum: 84.78% Approval: 72.91%	Support 11/5/13	Affirmative	
453	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Final Ballot	12/11/2013	12/20/2013	Quorum: 87.16% Approval: 86.40%	No Consensus 8/26/13	Affirmative	
454	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Final Ballot	12/13/2013	12/23/2013	Quorum: 84.34% Approval: 75.35%		Affirmative	
455	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-027-1	Additional Ballot	12/9/2013	12/31/2013	Quorum: 76.60% Approval: 65.71%	No Consensus 12/27/13	Affirmative	
456	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	1/10/2014	1/21/2014	Quorum: 76.92% Approval: 81.41%	Support 8/31/13	Affirmative	
457	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	1/8/2014	1/22/2014	Quorum: 7912% Approval: 74.63%	Support 11/11/13	Affirmative	
458	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 81.19%	Support 11/5/13	Affirmative	
459	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 90.23%	Support 11/5/13	Affirmative	

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460	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Additional Ballot	1/16/2014	1/29/2014	Quorum: 76.12% Approval: 92.17%	Support 11/5/13	Affirmative		
461	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	1/22/2014	1/31/2014	Quorum: 76.03% Approval: 71.86%	No Consensus 11/1/13	Affirmative	Ballot Period Extended to 2/4/14	
462	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.88% Approval: 83.44%	Support 11/5/13	Affirmative		
463	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.58% Approval: 91.51%	Support 11/5/13	Affirmative		
464	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Final Ballot	1/27/2014	2/5/2014	Quorum: 82.49% Approval: 82.45%	Support 8/31/13	Affirmative		
465	Project 2010-01	Project 2010-01 - Training - PER-005-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 84.02% Approval: 77.06%	Support 11/11/13	Affirmative		
466	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Final Ballot	1/31/2014	2/10/2014	Quorum: 81.79% Approval: 90.12%	Support 11/5/13	Affirmative		
467	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Additional Ballot	2/21/2014	3/3/2014	Quorum: 75.06% Approval: 62.63%	Support 9/5/12	Affirmative	Ballot Period Extended to 3/11/14	
468	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Final Ballot	3/28/2014	4/7/2014	Quorum: 78.21% Approval: 77.62%	Support 3/28/14	Affirmative		
469	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	4/1/2014	4/10/2014	Quorum: 76.92% Approval: 83.40%	Support 8/31/13	Affirmative		
470	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	4/4/2014	4/14/2014	Quorum: 78.03% Approval: 82.40%		--		
471	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	Initial Ballot	4/20/2014	4/24/2014	Quorum: 88.60% Approval: 82.07%	Support 4/23/14	Abstain		
472	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Final Ballot	4/25/2014	5/5/2014	Quorum: 80.37% Approval: 90.00%	Support--4/25/14	Affirmative		
473	Project 2013-04	Project 2013-04 - Voltage and Reactive Control - VAR-001-4, VAR-002-3	Final Ballot	4/23/2014	5/5/2014	Quorum: 83.84% Approval: 88.26%	Support--4/10/14	Affirmative		
474	Project 2014-04	Project 2014-04 - Physical Security - CIP-014-1	Final Ballot	5/1/2014	5/5/2014	Quorum: 92.53% Approval: 85.61%	Support--4/23/14	Abstain		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Initial Ballot	5/6/2014	5/15/2014	Quorum: 85.79%/79.08% Approval: 86.28%/78.81%	No Consensus--5/15/14	Reject		
476	Project 2012-13	Project 2012-13 - NUC - Nuclear Plant Interface Coordination	Initial Ballot	5/13/2014	5/22/2014	Quorum: 80.60% Approval: 97.36%	Support--5/20/14	Affirmative		
477	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) - PRC-005-X	Initial Ballot	5/23/2014	6/2/2014	Quorum: 85.42% Approval: 47.89%	Support	Affirmative		
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Initial Ballot	5/30/2014	6/9/2014	Quorum: 79.06% Approval: 17.02%	Does not Support--6/6/14	Negative		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Final Ballot	6/12/2014	6/23/2014	Quorum: Approval: 89.03%/83.46%	Support	Affirmative		
479	Project 2007-11	Project 2007-11 - Disturbance Monitoring - PRC-002-2	Additional Ballot	6/13/2014	6/23/2014	Quorum: 77.69% Approval: 52.29%	Support	Affirmative	Extended to achieve a quorum.	Last RSC Meeting
480	Project 2010-05.1	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Additional Ballot	6/20/2014	7/9/2014	Quorum: 76.98% Approval: 74.53%	Support	Affirmative	Extended to achieve a quorum.	
481	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Ballot	6/23/2014	7/2/2014	Quorum: 82.32%/82.59%/82.59%/82.85%/82.85%/82.06%/82.59%/82.85%/82.85%/81.00%/80.74% Approval: 68.57%/36.94%/47.87%/60.26%/61.67%/57.94%/30.99%/62.18%/63.07%/62.64%/64.70%	No Consensus--6/24/14	Affirmative Negative Affirmative Affirmative Affirmative Affirmative Negative Affirmative Affirmative		
482	Project 2012-13	Project 2012-13 NUC - Nuclear Plant Interface Coordination	Final Ballot	6/24/2014	7/3/2014	Quorum: 88.63% Approval: 97.23%	Support--6/23/14	Affirmative		
483	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions Rich HTML Content 1	Final Ballot	7/7/2014	7/16/2014	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 Yes			

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483	Project 2014-02	Rich Hume Content 1 http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/16/2014	Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-003-5 Yes CIP-010 Yes CIP-011 Yes Definitions Yes Support--7/14/14		
484	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Final Ballot	7/16/2014	7/25/2014	Quorum: 78.92% Approval: 58.88%	Support--7/23/14		
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.49%/80.15%/80.00%/80.83%/80.36% Approval: 91.38%/92.20%/89.51%/90.58%/87.09%	Support--7/24/14	Affirmative	
486	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 82.67% Approval: 55.77%		Affirmative	
487	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Initial Ballot	7/29/2014	8/7/2014	Quorum: 76.37% Approval: 76.91%		Affirmative	
488	Project 2012-13	Project 2009-03 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.66% Approval: 42.27%	Negative--8/14/14	Negative	
489	Project 2014-01	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.94% Approval: 79.75%	Support	Affirmative	
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 85.32%/86.01% Approval: 95.35%/95.86%	Support	Affirmative	
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and	Additional Ballot	9/3/2014	9/12/2014	Quorum: 84.33% Approval: 76.03%	Support--9/4/14	Affirmative	
492	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Additional Ballot	9/10/2014	9/19/2014	Quorum: 85.75%/84.96%/84.96%/85.22%/84.96%/85.22%/85.49%/85.22%/86.28%/83.11%/83.91% Approval: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%	TOP-001-3: Negative TOP-002-4: Affirmative TOP-003-3: Affirmative IRO-001-4: No consensus however the majority indicated an Affirmative vote IRO-002-4: Negative IRO-008-2: No consensus, a majority indicated a Negative and the others indicated abstention IRO-010-2: Affirmative IRO-014-3: Negative IRO-017-1: Affirmative Implementation Plan and Definitions: Affirmative 9/18/14		
493	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	9/23/2014	10/2/2014	Quorum: 79.94% Approval: 46.73%	Negative--10/1/14		
494	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	9/26/2014	10/6/2014	Quorum: 79.01% Approval: 53.02%	Affirmative--10/1/14		
495	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Additional Ballot	9/29/2014	10/8/2014	Quorum: 83.24%/84.82% Approval: 80.69%/84.05%	Affirmative--10/7/14	Affirmative	
496	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	10/1/2014	10/10/2014	Quorum: 82.93% Approval: 57.95%	Affirmative--10/7/14		
497	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Additional Ballot	10/3/2014	10/14/2014	Quorum: 80.54% Approval: 75.79% Approval:	Affirmative--10/7/14		
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		

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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		
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		

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
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		
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		

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
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% 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%	Affirmative--9/18/15		

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
						Approval: 87.36%			
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% Approval: 78.87%	Affirmative--3/10/16		
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%	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: 80.36%/93.43%	~~Affirmative--5/16/16~~		
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		
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%	~~Affirmative--1/23/17~~		

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: 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		

RSC Meeting #17-3, Agenda Item 6.3: Comment History

(As of 8/16/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
1.	N/A	Standards Project Prioritization Reference Document and Tool	Project Prioritization Tool		1/21/11	2/10/11	Yes 2/10/11
2.	Project 2007-23	Project 2007-23 - Violation Severity Levels	VSLs		1/20/11	2/18/11	Yes 2/18/11
3.	N/A	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	CAN-0015 Unavailability of NERC Tools		2/4/11	2/18/11	Yes 2/18/11
4	N/A	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	CAN-0016 CIP-001-1, R1		2/4/11	2/18/11	Yes 2/18/11
5.	N/A	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	CAN-0018 FAC-008, R.1.2.1		2/4/11	2/18/11	Yes 2/18/11
6.	Regional Standard	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		1/10/11	2/24/11	
7.	Project 2007-07	Project 2007-07 - Vegetation Management - FAC-003	FAC-003-2		1/27/11	2/28/11	Yes 2/28/11
8.	N/A	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	CAN-0017 CIP-007, R5		2/11/11	3/4/11	Yes 3/4/11
9.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1		2/4/11	3/7/11	Yes 3/7/11
10.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	COM-001 COM-002 IRO-001 IRO-014		1/18/11	3/7/11	Yes 3/7/11
11.	NERC RoP	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	RoP Section 1700		2/14/11	3/7/11	Yes 3/7/11
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11
13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11

RSC Meeting #17-3, Agenda Item 6.3: Comment History

(As of 8/16/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	Yes 4/8/11
15.	RFC RoP	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments			3/1/11	4/15/11	
16.	NERC RoP	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Appendices 3B and 3D		3/1/11	4/15/11	Yes 4/15/11
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	Yes 4/27/11
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	Yes 5/2/11
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	Yes 5/9/11
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	Yes 5/27/11
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	Yes 5/31/11
22.	Project 2007-03	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	TOP-001 through TOP-008 and PER-001		4/26/11	6/9/11	Yes 6/9/11
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	Yes 6/10/11
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	Yes 6/10/11
25.	N/A	CAN-0024--Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	CAN-0024 CIP-002 through CIP-009		5/20/11	6/10/11	
26.	N/A	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	CAN-0029 PRC-004-1 R1, R2 and R3		5/20/11	6/10/11	
27.	N/A	CAN-0030--Draft CAN-0030 Attestations	CAN-0030 Attestations		5/20/11	6/10/11	
28.	N/A	CAN-0039--Draft CAN-0039 DOE Form 407	CAN-0039 DOE Form 407		5/20/11	6/10/11	

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29.	Project 2010-05.1	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)			6/10/11	7/11/11	
30.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-025-2, MOD-027-1, PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		6/15/11	7/15/11	Yes 7/15/11
31.	Project 2010-07	Project 2010-07 – Generator Requirements at the Transmission Interface – Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards		6/17/11	7/17/11	Yes 7/15/11
32.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		6/15/11	8/1/11	Yes 8/1/11
33.	NERC RoP	Proposed Changes to NERC Rules of Procedure and associated Appendices (Appendix 4B – Sanction Guidelines; and Appendix 4C – Compliance Monitoring and Enforcement Program)	Appendices 4B and 4C		6/30/11	8/15/11	
34.	N/A	Compliance Application Notice (CAN) Process	CAN Process		8/15/11	9/6/11	Yes 9/6/11
35..	N/A	CAN-0016 CIP-001 R1 - Sabotage Reporting Procedure	CAN-0016 CIP-001, R1		8/15/11	9/6/11	Yes 9/6/11
36.	N/A	DRAFT CANs Posted for Comment and Retirement of CAN-0001 through 0004	CAN-0001 through 0004 Retirement		8/31/11	9/21/11	
37.	NERC RSDP	NERC 2012-2014 Reliability Standards Development Plan	2012-2014 RSDP		9/12/11	9/26/11	Yes 9/26/11
38.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		8/15/11	9/28/11	Yes 9/28/11
39.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	BES Definition		8/26/11	10/10/11	Yes 10/10/11

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40.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Technical Principles for Demonstrating BES Exceptions	Technical Principles for Demonstrating BES Exceptions		8/26/11	10/10/11	Yes 10/10/11
41.	N/A	New CAN Template, five DRAFT CANs for Industry review and CANs Status posted to NERC Compliance's Web site.	CANs		9/23/11	10/14/11	Yes 10/14/11
42.	RoP	Proposed Changes to NERC Rules of Procedure and All Appendices			9/2/11	10/17/11	
43.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Rules of procedure Modifications to Support BES Exception Requests	RoP Section 509, Section 1703 and Appendix 5C		9/13/11	10/27/11	Yes 10/27/11
44.	N/A	CAN-0010--Definition of "Annual" and Implementation of Annual Requirements	CAN-0010 Definition of Annual		10/10/11	10/31/11	Yes 10/31/11
45.	N/A	CAN-0011--PRC-005-1 R2: New Equipment	CAN-0011 PRC-005-1 R2		10/10/11	10/31/11	Yes 10/31/11
46.	N/A	CAN-0012--Completion of Periodic Activity Requirements During Implementation Plan	CAN-0012 Completion of Periodic Activity Requirements		10/10/11	10/31/11	Yes 10/31/11
47	N/A	CAN-0013--PRC-023 R1 and R2 Effective Dates for Switch-on-to-Fault Schemes	CAN-0013 PRC-023 R1 and R2		10/10/11	10/31/11	
48.	N/A	CAN-0015--Unavailability of NERC Software Tools	CAN-0015 NERC Tools		10/10/11	10/31/11	Yes 10/31/11
49.	N/A	CAN-0022--VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode	CAN-0022 VAR-002-1.1b R1 and R3		10/10/11	10/31/11	
50.	N/A	CAN-0024--CIP-002 R3 Routable Protocols and Data Diode Devices	CAN-0024 CIP-002, R3		10/10/11	10/31/11	Yes 10/31/11
51.	N/A	CAN-0026--TOP-006 R3 Protection Relays	CAN-0026 TOP-006, R3		10/10/11	10/31/11	Yes 10/31/11
52.	N/A	CAN-0028--TOP-006-1 R1.2 Reporting Responsibilities	CAN-0028 TOP-006-1, R1.2		10/10/11	10/31/11	

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53.	N/A	CAN-0020--TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages	CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002		10/19/11	11/9/11	
54.	N/A	CAN-0030--Attestations	CAN-0030		10/19/11	11/9/11	
55.	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	MOD-028, R3.1		10/3/11	11/16/11	Yes 11/16/11
56.	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Interpretation of COM-002-2, R2		10/4/11	11/18/11	Yes 11/18/11
57.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		10/5/11	11/18/11	Yes 11/18/11
58.	N/A	Draft Directive Regarding Generator Transmission Leads	Draft Directive #2011 CAG-001		10/17/11	11/18/11	Yes 11/18/11
59.	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 R1.1 by Progress Energy	Interpretation of CIP-006-1, R1.1		10/12/11	11/21/11	Yes 11/21/11
60.	N/A	CAN-0040 - BAL-003 Frequency Bias Calculation			11/2/11	11/23/11	
61.	N/A	CAN-0043 - PRC-005 Protection System Maintenance and Testing Evidence	PRC-005 Evidence		11/2/11	11/23/11	Yes 11/22/11
62.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1			12/8/11	Yes 12/8/11
63.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2			12/12/11	Yes 12/12/11
64.	N/A	Draft CAN-0027: TOP-003 R2 Coordination of Scheduled Outages	CAN-0027 TOP-003, R2		11/22/11	12/14/11	
65.	NERC RoP	Proposed Changes to the NERC Rules of Procedure and Associated Appendices			11/7/11	12/22/11	

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66.	NERC RoP	Notice of Revisions to Proposed New Sections 1.1.24 and 5.11 of Appendix 4C of the NERC Rules of Procedure, as Originally Posted for Comment on November 7, 2011			11/22/11	12/22/11	
67.	Regional Standard	Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		11/22/11	12/22/11	
68.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 (Version 5 CIP Standards)	Version 5 CIP Standards		11/7/11	1/6/12	Yes 1/6/12
69.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2	TOP-001-2 TOP-002-3 TOP-003-2		12/14/11	1/12/12	Yes 1/12/12
70.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition, Phase 2		1/4/12	2/3/12	Yes 2/3/12
71.	N/A	Order 754 - Request for Data or Information	Data Request		12/22/11	2/6/12	Yes 2/6/12
72.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001 COM-002 IRO-001-3		1/9/12	2/9/12	Yes 2/8/12
73.	WECC Regional Standard	Regional Reliability Standard BAL-004-WECC-02 - Automatic Time Error Correction	BAL-004-WECC-02		1/23/12	3/9/12	
74.	WECC Regional Standard	Regional Reliability Standard BAL-001-0.1a - Real Power Balancing Control Performance - WECC Variance	BAL-001-0.1a		1/23/12	3/9/12	
75.	N/A	NERC Functional Model Demand Response Functions and Entities	NERC Functional Model		2/13/12	3/14/12	
76.	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 for WECC	Interpretation of CIP-004-1		2/8/12	3/23/12	Yes 3/23/12

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77.	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Interpretation of CIP-002-1, R3		2/8/12	3/23/12	Yes 3/23/12
78.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Interpretation of VAR -002		2/8/12	3/23/12	Yes 3/23/12
79.	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing - PRC-005	PRC-005-2		2/28/12	3/28/12	Yes 3/28/12
80.	Project 2007-09	Project 2007-09 Generator Verification - MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		2/29/12	3/29/12	Yes 3/29/12
81.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - FAC-003-X, FAC-003-3	FAC-003-X FAC-003-3		3/9/12	4/9/12	Yes 4/9/12
82.	Project 2007-09	Project 2007-09 Generator Verification - MOD-025-2, MOD-027-1, and PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		2/29/12	4/16/12	Yes 4/16/12
83.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - PRC-005-1.1a	PRC-005-1.1a		3/2/12	4/16/12	Yes 4/16/12
84.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations	TOP-001 through TOP-008 and PER-001		3/22/12	4/20/12	Yes 4/20/12
85.	Project 2012-INT-02	Request for Interpretation - Project 2012-INT-02 TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		4/24/12	5/4/12	
86.	Project 2008-06	Project 2008-06 - Cyber Security Order 706 Version 5 CIP	CIP-002 and CIP-003 - Comment Form A		4/12/12	5/21/12	Yes 5/20/12
			CIP-004 thru CIP-007 - Comment Form B		4/12/12	5/21/12	Yes 5/20/12
			CIP-008 thru CIP-011 - Comment Form C		4/12/12	5/21/12	Yes 5/20/12

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			Definitions and Implementation Plan - Comment Form D		4/12/12	5/21/12	Yes 5/20/12
87.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		4/25/12	5/24/12	Yes 5/24/12
88.	Project 2007-12	Project 2007-12 Frequency Response Technical Conferences			5/30/12	6/15/12	
89.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003		5/7/12	6/20/12	Yes 6/20/12
90.	N/A	Adequate Level of Reliability Revised Definition and Associated Documents	Adequate Level of Reliability (ALR)		4/25/12	6/25/12	Yes 6/25/12
91.	N/A	Order 754 - Request for Data or Information	Data Request		5/11/12	6/25/12	Yes 6/25/12
92.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR - 002 for Constellation	Interpretation of VAR -002		5/22/12	6/27/12	Yes 6/27/12
93.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		5/29/12	6/27/12	Yes 6/27/12
94.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserve	BAL-001-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-002-2		6/4/12	7/3/12	Yes 7/3/12
			BAL-012-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-013-1		6/4/12	7/3/12	Yes 7/3/12
95.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		5/21/12	7/5/12	Yes 7/5/12
96.	N/A	Cost Effective Analysis Process (CEAP) for NERC ERO Standards	CEAP		5/7/12	7/6/12	Yes 7/6/12
97.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001, COM-002 and IRO-001-3		6/7/12	7/6/12	Yes 7/6/12
98.	Project 2006-02	Project 2006-02 – Assess Transmission Future Needs and Develop Transmission Plans	TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12		6/19/12	7/9/12	Yes 7/9/12

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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	
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

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112.	N/A	Definition of Adequate Level of Reliability	Adequate Level of Reliability (ALR)		8/15/12	9/13/12	Yes 9/13/12
113.	N/A	2013-2015 Reliability Standards Development Plan	2013-2015 RSDP		8/17/12	9/18/12	Yes 9/18/12
114.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols	COM-003-1		8/22/12	9/20/12	Yes 9/20/12
115.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		8/29/12	9/27/12	
116.	SPP Regional Standard	Regional Reliability Standard PRC-006-SPP-01 Automatic Underfrequency Load Shedding	PRC-006-SPP-01		8/15/12	9/28/12	
117.	Project 2008-06 Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		9/11/12	10/10/12	Yes 10/10/12
			RSAW		9/11/12	10/10/12	Yes 10/10/12
118.	MRO SPM	Regional Reliability Standards - MRO Standards Process Manual			8/28/12	10/11/12	
119.	N/A	Standard Process Manual Revisions to Implement SPIG Recommendations	SPIG Reco		8/29/12	10/12/12	Yes 10/10/12
120.		Revisions to Outstanding VRFs and VSLs			9/5/12	10/19/12	
121.	Project 2013-01	Project 2013-01 - Cold Weather Preparedness			9/25/12	10/24/12	
122.	Project 2007-09	Project 2007-09 - Generator Verification			9/28/12	10/29/12	
123.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System			10/4/12	11/5/12	
124.	2007-12	Project 2007-12 - Frequency Response			10/5/12	11/7/12	
125.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		10/26/12	11/7/12	
126.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025		10/5/12	11/7/12	

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127.	N/A	IRO-006-WECC-2			10/3/12	11/16/12	
128.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B			10/5/12	11/19/12	
129.	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		10/22/12	12/5/12	Yes 12/5/12
130.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		10/25/12	12/10/12	Yes 12/10/12
131.	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	- Interpretation of CIP-003-3		11/9/12	12/10/12	Yes 12/10/12
132.	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	- Interpretation of CIP-007-3		11/9/12	12/10/12	Yes 12/10/12
133.	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols - RSAW	COM-003-1		11/14/12	12/13/12	Yes 12/13/12
			COM-003-1 RSAW		11/14/12	12/13/12	Yes 12/13/12
134.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		11/16/12	12/17/12	Yes 12/17/12
135.	Project 2012-INT-05	Project 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		11/6/12	12/20/12	Yes 12/20/12
136.	N/A	Standard Processes Manual to Implement SPIG Revisions	SPIG Reco		11/21/12	12/20/12	Yes 12/20/12
137.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B	TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12		12/10/12	1/11/13	Yes 1/11/13
138.	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	PRC-024-1		12/12/12	1/11/13	Yes 1/11/13
139.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-012-1	BAL-012-1		11/30/12	1/14/13	Yes 1/14/13
140.	N/A	Reliability Guideline--Draft Generating Unit Winter Weather Readiness - Current Industry Practices			12/20/12	2/4/13	Yes 2/4/13
141.	Project 2010-05-1	Project 2010-05-1 Protection System Misoperations					Yes 2/20/13
142.	Project 2007-09	Project 2007-09 Generator Verification - PRC-024-1	PRC-024-1	Formal	1/25/13	2/25/13	Yes 2/25/13

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143.	N/A	Rapid Revision Procedure		Informal	2/25/13	3/6/13	Yes 3/6/13
144.	Project 2010-13-2	Project 2010-13-2 - Phase 2 of Relay Loadability - Generation - PRC-025-1	PRC-025-1	Formal	1/25/13	3/11/13	Yes 3/11/13
			Supplemental SAR	Informal	1/25/13	3/11/13	Yes 3/11/13
			Cost Effectiveness	CEAP Pilot	1/25/13	3/11/13	Yes 3/11/13
			RSAW	Feedback	1/25/13	3/11/13	Yes 3/11/13
145.	Project 2012-INT-04	Interpretation 2012-INT-04 - Interpretation of CIP-007 for ITC	Interpretation of CIP-007	Formal	2/6/13	3/22/13	Yes 3/22/13
146.	Project 2012-INT-06	Interpretation 2012-INT-06 - Interpretation of CIP-003 for Consumers Energy	Interpretation of CIP-003	Formal	2/6/13	3/22/13	Yes 3/22/13
147.	Project 2012-08-1	Project 2012-08-1 - Phase 1 of Glossary Updates--Statutory Definitions	Glossary of Terms	Formal	2/21/13	3/22/13	Yes 3/22/13
148.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003-1	COM-003-1	Formal	3/7/13	4/5/13	Yes 4/5/13
			RSAW	Feedback	3/7/13	4/5/13	Yes 4/5/13
149.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-001-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-002-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-013-1	Formal	3/12/13	4/25/13	Yes 4/25/13
150.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)	Draft SAR	Informal	4/5/13	5/6/13	Yes 5/6/13
			PRC-005-3	Formal	4/5/13	5/6/13	Yes 5/613
151.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation	PRC-023-3 PRC-025-1	Formal	4/25/13	5/24/13	Yes 5/24/13
152.	Project 2007-11	Project 2007-11 - Disturbance Monitoring — PRC-002 and PRC-018	SAR	Informal	5/03/13	6/03/13	Yes 6/3/13
153.	Project 2007-11	Project 2007-11 - Disturbance Monitoring PRC-002 and PRC-018	Request for Information	Informal	6/05/13	7/05/13	
154.	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	PRC-001 and PRC-027		6/04/13	7/03/13	Yes 7/03/13

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
155.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition		5/29/13	7/12/13	Yes 7/12/13
156.	TRE Regional Standard	Regional Reliability Standard - BAL-001-TRE-01	BAL-001-TRE-01		5/31/13	7/15/13	
157.	N/A	NPCC Regional Standards Process Manual	NPCC RSPM		6/06/13	7/22/13	
158.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003-1		6/20/13	7/19/13	Yes 7/19/13
159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13
163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13

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169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	Yes 9/4/13
170	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System – Phase 2	BES Definition Phase 2	Formal	8/6/13	9/4/13	Yes 9/4/13
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	Yes 9/9/13
172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	Yes 9/13/13
173	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-001-1 FAC-002-1	5-year review	8/1/13	9/16/13	Yes 9/16/13
174	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-003-3 FAC-008-3 FAC-010-2.1 FAC-011-2 FAC-013-2 FAC-014-2	5-year review	8/1/13	9/16/13	Yes 9/16/13
175	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	BAL-002-2	Formal	8/2/13	9/16/13	Yes 9/16/13
176	Project 2009-03	Project 2009-03 — Five-Year Review of Emergency Operations EOP-001, EOP-002, EOP-003, and IRO-001	EOP-001-2.1b EOP-002-3.1 EOP-003-2	5-year review	8/6/13	9/19/13	Yes 9/19/13
177	Project 2012-09	Project 2012-09 IRO Five-Year Review	IRO-003-2 IRO-004-2 IRO-005-4 IRO-006-5 IRO-006-East IRO-008-1 IRO-009-1 IRO-010-1a	5-year review	8/7/13	9/20/13	Yes 9/20/13
178	Project 2008-02	Project 2008-02 Undervoltage Load Shedding	Revised SAR	Informal	9/10/13	10/9/13	Yes 10/9/13
179	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	9/4/13	10/18/13	Yes 10/18/13
180	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition	Formal	9/27/13	10/28/13	Yes 10/28/13

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181	Project 2007-02	Project 2007-02 Operating Personnel Communications Protocols	COM-002-4	Formal	10/21/13	11/7/13	Yes 11/4/13
182	Project 2010-01	Project 2010-01 Training	PER-005-2	Formal	9/27/13	11/12/13	Yes 11/12/13
183	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	Various INT Standards	Formal	9/30/13	11/13/13	Yes 11/13/13
184	Project 2012-05	Project 2012-05 ATC Revisions (MOD A)	MOD-001-2	Formal	10/4/13	11/20/13	Yes 11/18/13
185	Project 2010-03	Project 2010-03 Modeling Data (MOD B)	MOD-032-1, MOD-033-1	Formal	10/07/13	11/20/13	
186	Project 2010-04	Project 2010-04 Demand Data (MOD C)	MOD-031-1	Formal	10/09/13	11/22/13	Yes 11/22/13
187	Project 2013-04	Project 2013-04 Voltage and Reactive Control	VAR-001-4, VAR-002-3	Formal	10/11/13	11/25/13	Yes 11/25/13
188	Project 2009-03	Project 2009-03 Emergency Operations	SAR	Informal	11/06/13	12/05/13	Yes 12/5/13
189	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-002-2	Formal	10/28/13	12/11/13	Yes 12/11/13
190	Project 2007-11	Project 2007-11 - Disturbance Monitoring	PRC-002-2	Formal	11/01/13	12/16/13	Yes 12/16/13
191	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-027	Formal	11/04/13	12/18/13	Yes 12/18/13
192	Project 2014-01	Project 2014-01 - Standards Applicability for Dispersed Generation Resources	SAR	Formal	11/20/13	12/19/13	Yes 12/19/13
193	Project 2010-01	Project 2010-01 Training - PER-005-2	PER-005-2	Formal	12/4/13	1/22/14	Yes 1/17/14
194	Project 2010-03	Project 2010-03 Modeling Date - MOD B	MOD-033-1	Formal	12/6/13	1/22/14	Yes 1/21/14
195	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	INT-004-3 INT-010-2	Formal	1/10/14	1/24/14	Yes 1/22/14
196	Project 2007-02	Project 2007-02 Operating Personnel	COM-002-4	Formal	1/22/14	1/31/14	Yes 1/31/14
197	Project 2014-02	Project 2014-02 Standard Authorization Request – Cyber Security Standards	CIP SAR	Informal	1/17/14	2/18/14	Yes 2/18/14
198	2014 Work Plan	2014 Work Plan for NERC Reliability Standards Development	2014 Work plan			2/21/13	Yes 2/21/14

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199	Project 2010-17	Project 2010-17 Definition of Bulk Electric System - Phase 2	BES	Informal	1/29/14	2/27/14	Yes 2/27/14
200	Project 2010-05.1	Project 2010-05.1 Protection System: Phase 1 (Misoperations) - PRC-004-3	PRC-004-3	Formal	1/17/14	3/11/14	Yes 3/2/14
201	Project 2012-13	Project 2012-13 NUC-Nuclear Plant Interface Coordination Standard Authorization Request	NUC-001-2.1 SAR	Informal	2/12/14	3/13/14	Yes 3/13/14
202	Project 2010-05.2	Project 2010-05.2 Special Protection Systems (Phase 2 of Protection Systems) - SAR	SAR	Informal	2/18/14	3/19/14	Yes 3/19/14
203	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	SAR	Formal	02/21/14	03/24/14	Yes 3/24/14
204	Project 2014-03	Technical Conferences on Revisions to TOP/IRO Reliability Standards	Technical Conference Topics	Informal	03/11/14	03/24/14	
205	Project 2014-04	Project 2014-04 - Physical Security	SAR	Informal	03/21/14	03/28/14	Yes 3/28/14
206	Project 2010-14.2	Project 2010-14.2 - Periodic Review of BAL Standards	Reco to Revise BAL-005 and BAL-006	Formal	02/21/14	04/07/14	
207	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Informal	03/11/14	04/09/14	Yes 4/9/14
208	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	02/25/14	04/10/14	Yes 4/10/14
209	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-002-3	Formal	02/27/14	04/14/14	Yes 4/14/14
210	Project 2008-02	Project 2008-02 - Undervoltage Load Shedding - PRC-010, PRC-020, PRC-021 and PRC-022	PRC-010-1	Informal	03/17/14	04/16/14	Yes 4/16/14
211	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	CIP-014-1	Formal	04/10/14	04/24/14	Yes 4/24/14
212	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Informal	03/28/14	04/28/14	Yes 4/28/14

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213	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	04/17/14	05/05/14	Yes 5/5/14
214	Project 2010-02	Project 2010-02 – Connecting New Facilities to the Grid	FAC-001-1 FAC-002-1	Formal	04/01/14	05/15/14	Yes 5/15/14
215	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Informal	04/22/14	05/21/14	Yes 5/21/14
216	Project 2012-13	Project 2012-13 Nuclear Plant Interface Coordination	NUC-001-3	Formal	04/08/14	05/22/14	Yes 5/22/14
217	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays)	PRC-005-X	Formal	04/17/14	06/03/14	Yes 6/3/14
218	Project 2010-13.3	Project 2010-13.3 Relay Loadability: Stable Power Swings	PRC-026-1	Formal	04/25/14	06/09/14	Yes 6/9/14
219	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	05/09/14	06/25/14	Yes 6/25/14
221	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Informal	05/23/14	06/23/14	Yes 6/23/14
222	Project 2010-05-1	Project 2010-05-1 Protection System – Phase 1 – Misoperations	PRC-004	Formal	05/16/14	07/09/14	Yes 7/9/14
223	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	05/19/14	07/02/14	Yes 7/2/14
224	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-002 to CIP-011	Formal	06/02/14	07/17/14	Yes 7/16/14
225	Project 2015-2017	Project 2015-2017 Reliability Standard		Informal		7/21/14	Yes 7/21/14

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Development Plan					
226	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Formal	7/16/14	7/25/14	Yes 7/25/14
227	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	06/12/14	7/29/14	Yes 7/29/14
228	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	06/13/14	07/30/14	Yes 7/30/14
229	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Formal	06/23/14	08/8/14	Yes 8/6/14
230	Project 2010-14-2	Project 2010-14-2 Balancing Authority Reliability-based Control Standard Authorization Request for BAL-005 and BAL-006	BAL-005 BAL-006	Informal	07/16/14	08/14/14	Yes 8/12/14
231	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Formal	07/2/14	08/15/14	Yes 8/13/14
232	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-004-2.1a(X) PRC-004-3(X)	Formal	07/10/14	08/26/14	Yes 8/25/14
233	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays) – PRC-005-X	PRC-005-X	Formal	07/30/14	09/12/14	Yes 9/12/14
234	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	08/6/14	09/19/14	Yes 9/22/14
235	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	08/19/14	10/03/14	Yes 10/2/14

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236	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	09/26/14	10/06/14	Yes 10/6/14
237	Project 2008-02	Project 2008-02: Underfrequency Load Shedding (UFLS)	PRC-006-2	Formal	08/21/14	10/08/14	Yes 10/7/14
238	Project 2013-03	Project 2013-03: Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	08/27/14	10/10/14	Yes 10/10/14
239	NERC Rules of Procedure	NERC Rules of Procedure	NERC Rules of Procedure	Formal	08/26/14	10/10/14	Yes 10/14/14
240	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems Phase 2 of Protection Systems	RAS Definition	Formal	08/29/14	10/14/14	Yes 10/14/14
241	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	VAR-002-2b(X) VAR-002-4	Formal	08/27/14	10/16/14	Yes 10/16/14
242	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-003-6 CIP-010-2 CIP-003-X CIP-004-X CIP-007-X CIP-010-X CIP-011-X	Formal	09/03/14	10/17/14	Yes 10/17/14
243	Project 2009-03	Project 2009-03 Emergency Operations	EOP-011-1	Formal	09/05/14	10/20/14	Yes 10/20/14
244	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Preliminary Draft 5)	PRC-027-1	Informal	10/01/14	10/21/14	Yes 10/21/14
245	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	09/05/14	10/21/14	Yes 10/21/14
246	Project 2014-01	Project 2014-01 Applicability for Dispersed Generation	PRC-004-2.1a(X) PRC-004-4	Formal	09/05/14	10/22/14	Yes 10/22/14
247	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	10/10/14	11/10/14	Yes 11/10/14
248	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1	TPL-007-1	Formal	10/28/14	11/21/14	Yes 11/24/14
249	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	11/04/14	11/24/14	Yes 11/25/14
250	Project 2014-01	Project 2014-01 – Standards Applicability	PRC-001-1.1 PRC-019-2	Formal	11/05/14	12/23/14	Yes 12/22/14

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		for Dispersed Generation Resources	PRC-024-1				
251	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	12/29/14	1/7/15	Yes 1/6/15
252	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-003-7 CIP-004-7 CIP-007-7 CIP-010-3 CIP-011-3 CIP-003-7 CIP-010-3 Implementation Plan	Formal	12/30/14	1/9/15	Yes 1/9/15
253	Project 2014-04	Project 2014-04 Physical Security SAR	SAR	Informal	12/15/14	1/13/15	Yes 1/12/15
254	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	White Paper Appendix A Appendix B	Informal	12/22/14	1/20/15	Yes 1/20/15
255	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-5	Informal	12/22/14	1/20/15	Yes 1/22/15
257	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	1/29/15	3/18/15	Yes 3/16/15
258	Reliability Guideline	Reliability Guideline: Loss of Real-Time Reliability Tools Capability/Loss of Equipment Significantly Affecting ICCP Data		Formal	2/19/15	4/6/15	Yes 4/6/15
259	Project 2008-02.2	Project 2008-02.2 Phase 2 UVLS: Misoperation	PRC-010-2	Formal	2/20/15	4/7/15	Yes 4/7/15
260	Project 2014-04	Project 2014-04 Physical Security	CIP-014-2	Formal	2/20/15	4/9/15	Yes 4/9/15
261	Project 2015-04	Project 2015-04 Alignment of Terms	SAR	Formal	2/24/15	4/13/15	Yes 4/13/15
262	Project 2007-17.4	Project 2007-17.4 PRC-005 Order No. 803 Directives	SAR	Informal	3/12/15	4/10/15	Yes 4/13/15
263	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	SAR	Informal	3/16/15	4//15/15	Yes 4/15/15
264	Project 2010-14.2.2	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	SAR	Informal	3/17/15	4//15/15	Yes 4/15/15

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265	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-008-1	Informal	3/27/15	5/11/15	Yes 5/11/15
266	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-006-2	Informal	3/27/15	5/11/15	Yes 5/11/15
267	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-005-2	Informal	3/27/15	5/11/15	Yes 5/11/15
268	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-004-2	Informal	3/27/15	5/11/15	Yes 5/11/15
269	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Draft 5)	PRC-027-1	Formal	4/1/15	5/15/15	Yes 5/15/15
270	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	SAR	Informal	4/16/15	5/19/15	Yes 5/19/15
271	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems – RAS	PRC-012-2	Informal	4/30/15	5/20/15	Yes 5/20/15
272	Project 2015-03	Project 2015-03 Periodic Review of System Operating Limit Standards	FAC-010-3 FAC-011-3 FAC-014-2	Formal	5/4/15	6/17/15	Yes 6/17/15
273	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	IRO-006-East-2 IRO-009-2	Formal	5/21/15	7/8/15	Yes 7/8/15
274	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	PRC-005-3	Formal	6/11/15	7/10/15	Yes 7/10/15
275	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generations Resources	PRC-004-2.1 PRC-005-2 PRC-005-3	Informal	6/12/15	7/13/15	Yes 7/13/15
276	Project 2015-07	Project 2015-07 Internal Communications Capabilities	COM-001-2	Informal	6/11/15	7/15/15	Yes 7/15/15
277	Project 2015-04	Alignment of Terms	Glossary Terms	Formal	6/12/15	7/23/15	Yes 7/23/15
278	Project 2009-02	Real-time Monitoring and Analysis Capabilities	SAR	Formal	7/16/15	8/17/15	Yes 8/17/15
279	NERC 2016-2018	Reliability Standards Development Plan	Development Plan	Formal	7/16/15	8/17/15	Yes 8/17/15
280	Project 2015-08	Emergency Operations	EOP-004-2 EOP-005-2 EOP-006-2 EOP-008-1	Informal	7/21/15	8/19/15	Yes 8/19/15
281	Project 2010-14.1	Phase 1 of Balancing Authority Reliability-	BAL-002-2	Formal	7/7/15	8/20/15	Yes 8/20/15

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		based Controls					
282	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	BAL-004-0	Survey	8/12/15	8/25/15	Yes 8/25/15
283	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	7/29/15	9/11/15	Yes 9/11/15
284	Project 2007-06	System Protection Coordination	PRC-027-1	Formal	7/29/15	9/11/15	Yes 9/11/15
285	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 BAL-006-3	Formal	7/30/15	9/14/15	Yes 9/14/15
286	Project 2007-17.4	PRC-005 FERC Order No. 803 Directive	PRC-005-6	Formal	7/30/15	9/16/15	Yes 9/16/15
287	Project 2010-04.1	MOD-031 FERC Order No. 804 Directives	MOD-031-2	Formal	7/31/15	9/18/15	Yes 9/18/15
288	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010-3 FAC-011-3 FAC-014-2	Informal	8/20/15	9/21/15	Yes 9/21/15
289	Project 2010-07.1	Vegetation Management	FAC-003-3	Informal	8/24/15	9/28/15	Yes 9/28/15
290	Project 2010-05.3	Phase 3 of Protection Systems: Remedial Action Schemes	PRC-012-2	Formal	8/20/15	10/5/15	Yes 10/5/15
291	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	9/24/15	11/9/15	Yes 11/9/15
292	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls	BAL-004-0	Formal	9/24/15	11/12/15	Yes 11/12/15
293	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	9/25/15	11/16/15	Yes 11/16/15
294	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	10/6/15	11/19/15	Yes 11/19/15
295	Project 2010-07.1	Vegetation Management	FAC-003-3	Formal	10/30/15	12/16/15	Yes 12/16/15
296	Project 2015-10	Single Points of Failure SAR	TPL-001	Informal	11/12/15	12/17/15	Yes 12/17/15
297	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	11/25/15	1/8/16	Yes 1/8/16
298	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 FAC-001-3 BAL-006-2	Formal	12/31/15	1/11/16	Yes 1/11/16
299	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	12/10/15	1/25/16	Yes 1/25/16
300	Project 2016-01	Modifications to TOP and IRO Standards	SAR	Informal	1/22/16	2/22/16	Yes 2/22/16
301	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	2/3/16	3/18/16	Yes 3/18/16
302	Project	Modifications to CIP	SAR	Informal	3/23/16	4/21/16	Yes

RSC Meeting #17-3, Agenda Item 6.3: Comment History

(As of 8/16/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2016-02	Standards					4/21/16
303	Project 2007-06.2	Phase 2 of System Protection Coordination	PER-006-1 & Two Definitions	Formal	3/10/16	4/25/16	Yes 4/25/16
304	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	3/23/16	5/9/16	Yes 5/6/16
305	CEP	Cost Effectiveness Pilot	TPL-001-4	Informal	4/27/16	5/26/16	Yes 5/26/16
306	Project 2013-03	Geomagnetic Disturbance Mitigation Revised White Papers	SAR	Informal	5/12/16	6/13/16	Yes 6/13/16
307	Project 2015-10	Single Points of Failure	SAR	Informal	5/26/16	6/24/16	Yes 6/24/16
308	Project 2016-02	Modifications to CIP Standards	SAR	Informal	6/1/16	6/30/16	Yes 6/30/16
309	Draft 2017-2019	Reliability Standards Development Plan	RSDP	Informal	6/20/16	7/19/16	Yes 7/19/16
310	EPR	Enhanced Periodic Review Standing Review Team	Standards Grading	Informal	6/30/16	8/1/16	Yes 8/1/16
311	Project 2016-01	Modifications to TOP and IRO Standards	IRO-002-5 TOP-001-4	Formal	6/20/16	8/3/16	Yes 8/3/16
312	Project 2015-09	Establish and Communicate System Operating Limits	FAC-014-3	Formal	7/14/16	8/12/16	Yes 8/12/16
313	Project 2015-09	Establish and Communicate System Operating Limits	FAC-011-4	Formal	7/14/16	8/12/16	Yes 8/12/16
314	Project 2015-08	Emergency Operations	EOP-005-3 EOP-006-3 EOP-008-2	Formal	6/30/16	8/15/16	Yes 8/15/16
315	Project 2016-02	Modifications to CIP Standards	CIP-003-7	Formal	7/21/16	9/6/16	Yes 9/6/16
316	FMAG	Functional Model Advisory Group	Reliability Functional Model and Technical Document	Informal	7/21/16	9/7/16	Yes 9/7/16
317	Project 2015-08	Emergency Operations	EOP-004-4	Formal	7/25/16	9/8/16	Yes 9/8/16
318	Project 2015-INT-01	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	CIP-002-5.1	Formal	7/27/16	9/12/16	Yes 9/12/16
319	Project 2016-01	Modifications to TOP and IRO Standards SAR	TOP-001-3 IRO-002-4	Formal	8/31/16	10/17/16	Yes 10/14/16
320	Project 2016-04	Modifications to PRC-025-1 SAR	PRC-025-1	Formal	9/16/16	10/18/16	Yes 10/18/16
321	Project 2016-03	Cyber Security Supply Chain Management	SAR	Informal	10/20/16	11/18/16	Yes 11/18/16
322	Project	Modifications of CIP	CIP-003-TCA	Informal	11/1/16	11/18/16	Yes

RSC Meeting #17-3, Agenda Item 6.3: Comment History

(As of 8/16/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2016-02	Standards					11/18/16
323	Project 2016-02	Modifications of CIP Standards	CIP-003-7	Formal	11/23/16	12/5/16	Yes 12/5/16
324	Project 2015-08	Emergency Operations	EOP-005-3 EOP-006-3	Formal	10/26/16	12/9/16	Yes 12/9/16
325	Project 2015-08	Emergency Operations	EOP-004-4	Formal	11/18/16	1/6/17	Yes 1/6/17
326	Project 2013-03	Geomagnetic Disturbance Mitigation	SAR	Informal	12/16/16	1/20/17	Yes 1/20/17
327	Project 2016-02	Modifications of CIP Standards	CIP-003-7(i)	Formal	12/12/16	1/25/17	Yes 1/25/17
328	Project 2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training and Qualifications Standard (PER)	PER-001-0.2 PER-003-1 PER-004-2	Formal	1/10/17	2/23/17	Yes 2/23/17
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 Processes Manual	SPM	Formal	3/20/17	5/3/17	Yes 5/3/17
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

RSC Meeting #17-3, Agenda Item 6.3: Comment History

(As of 8/16/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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

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-2

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.

4. **Applicability:**

   4.1. Generator Owner

   4.2. Planning Coordinator

   4.3. Distribution Providers that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program.

   4.4. Transmission Owners that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program.

5. **Effective Date:**

   The first day of the first calendar quarter following applicable governmental and regulatory approvals.

B. Requirements

Rationale for Requirement R1: Figure 1 of this document shows the NPCC underfrequency criteria for the Eastern Interconnection portion of NPCC. Note that Figure 1 also shows the NERC criteria as defined in the NERC PRC Standard on UFLS.

R1. Each Planning Coordinator in the Eastern Interconnection portion of NPCC shall design an UFLS program 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: Medium] [Time Horizon: Long Term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, system studies and/or real-time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

R2. Each Planning Coordinator shall provide UFLS island boundaries, as identified per the NERC PRC Standard on UFLS, to Distribution Providers, Generator Owners, and Transmission Owners within 30 days of receipt of a request. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

R3. Each Planning Coordinator shall, within 30 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 acceptable UFLS program performance. *[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 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.

4.2. Alternatively, the program can be implemented collectively by multiple Distribution Providers or Transmission Owners with less than 100 MW of individual peak net Load, as long 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.

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).

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 notify its Planning Coordinator within 30 days, and: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

5.1. Each Distribution Provider or Transmission Owner applicable to Attachment C, Table 1, within 90 calendar days of informing of its Planning Coordinator that

tolerances cannot be met, determine if tolerances can be met through adjustments and notify the Planning Coordinator of the determination and;

5.1.1. 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;

5.1.2. If adjustments are not possible then provide its Planning Coordinator with a technical study within 180 calendar days 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.

5.2. Each Distribution Provider or Transmission Owner applicable to Attachment C, Table 2 or Table 3, within 90 calendar days after informing the Planning Coordinator, determine if tolerances can be met through adjustments and notify the Planning Coordinator of the determination, and;

5.2.1. If adjustments are possible, within 90 calendar days make the adjustments of determining that adjustments are possible and notify the Planning Coordinator when complete, or;

5.2.2. If adjustments are not possible, then 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 UFLS Attachment C Table 2 or Attachment C Table 3.

5.3. Each Distribution Provider or Transmission Owner in the Quebec Interconnection, within 90 calendar days after informing the Planning Coordinator, determine if tolerances can be met through adjustments and notify the Planning Coordinator of the determination, and;

5.3.1. If adjustments are possible, within 180 calendar days make the adjustments of determining that adjustments are possible and notify the Planning Coordinator when complete, or;

5.3.2. If adjustments are not possible, then 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.

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.

Rationale for Requirement R6: Operation of underfrequency relays results directly in load being shed, interrupting service to customers. The security of underfrequency

relays against misoperation is therefore paramount. The 100 ms minimum time delay specified in R6 serves to prevent premature activation of these relays during short-lived transient frequency excursions that may occur on a localized basis in the absence of a serious system event wherein UFLS would be appropriate. This intentional delay helps to ensure that the relays activate only for frequency excursions that are due to actual system events that require automatic UFLS to reestablish the balance of generation to load.

R6. Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with a 100 ms minimum time delay. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M6. Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R6.

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 days of any changes to those thresholds. *[Violation Risk Factor: Medium] [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 within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

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.

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 universally, 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 months between updates, to its Planning Coordinator of the actual net Load projected to be 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 actual metered Load through the switches that would disconnect load if triggered by the UFLS relays. If there is no local metering of the load through said switches, the load may be calculated from measurements made at the nearest available metering. (e.g., upstream metering on the distribution feeder that supplies the load to be shed). *[Violation Risk Factor: Lower] [Time Horizon: Long Term 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: High] [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 to its Planning Coordinator within 45 days of the Planning Coordinator's request. *[Violation Risk Factor: High] [Time Horizon: Operations 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: High] [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.

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. Each Generator Owner of 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 shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

15.1. Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

15.2. Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

15.3. 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 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 R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R15.

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: High] [Time Horizon: Long Term Planning]*

M16. 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 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: High] [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 emails, 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: High] [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.

Figure 1
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Eastern Interconnection Frequency Hz
Design Performance Requirements

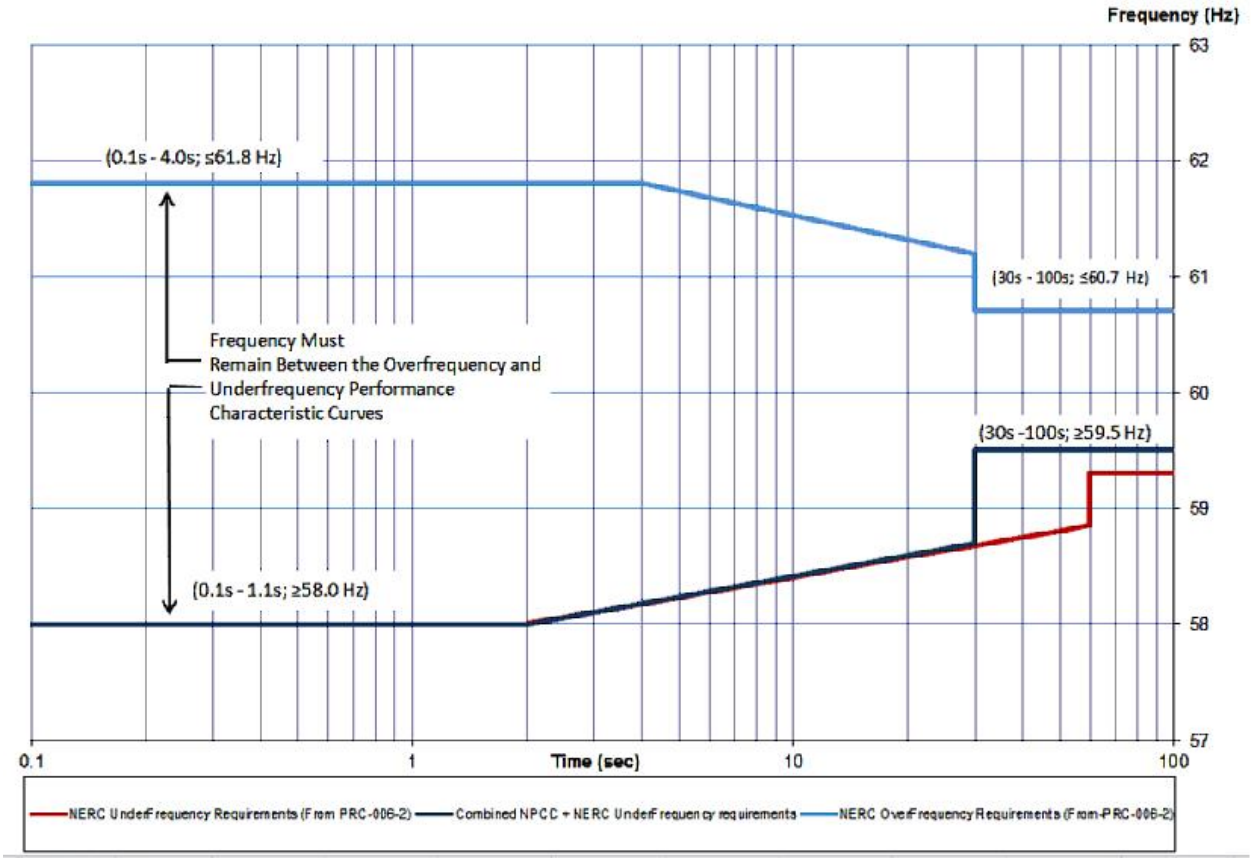
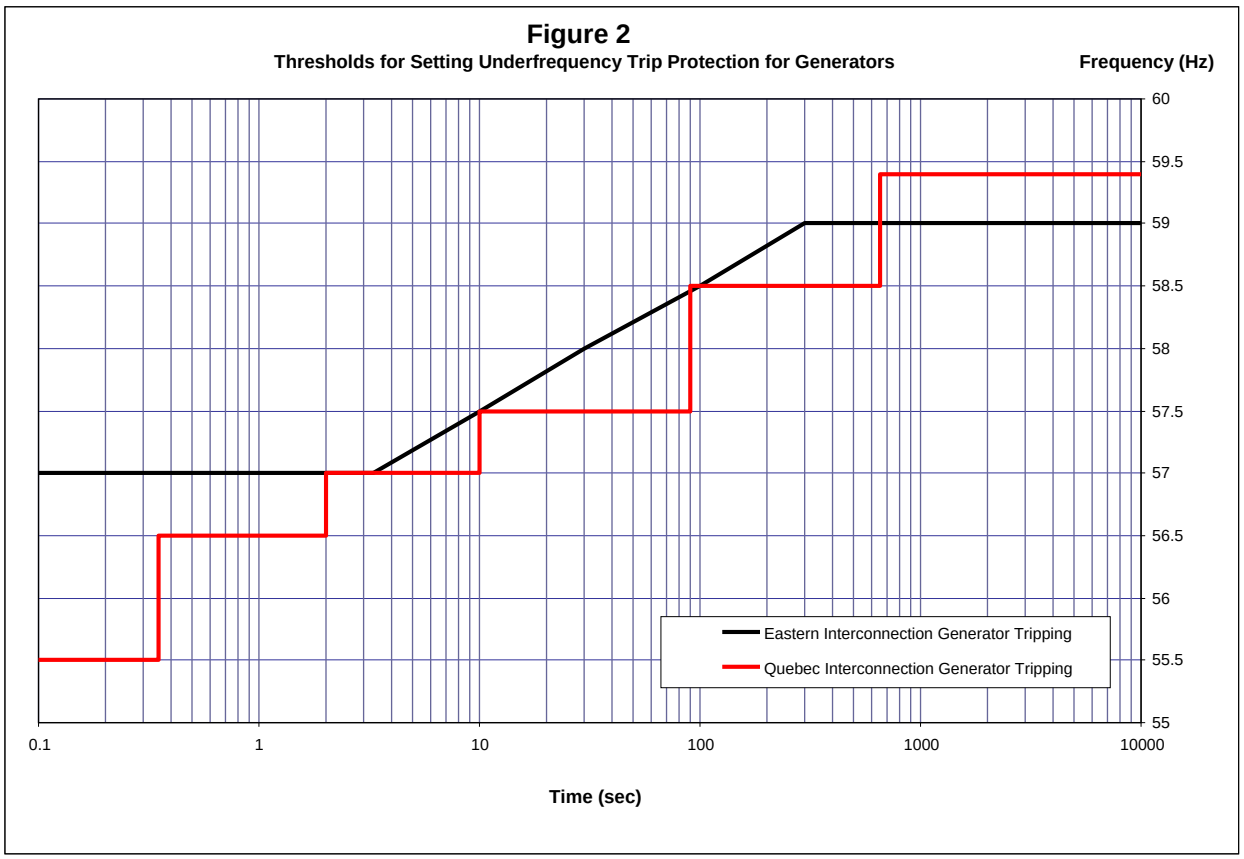


Figure 2
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators



C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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, 9,10, and 11.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 7, 8, and 9.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 16.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 17.

The Generator Owner shall keep evidence for three calendar years for Measures 12, 13, 14, 15, and 18.

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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	Planning Coordinator did not design a UFLS program with the performance characteristics outlined in Figure 1
R2	The Planning Coordinator identified and provided the UFLS island boundaries within its Planning Coordinator Area to their DPs, GOPs and TOs as necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies.	The Planning Coordinator identified and provided the UFLS island boundaries within its Planning Coordinator Area to their DPs, GOPs and TOs as necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies.	The Planning Coordinator identified and provided the UFLS island boundaries within its Planning Coordinator Area to their DPs, GOPs, and TOs as necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies.	The Planning Coordinator identified and provided the UFLS island boundaries within its Planning Coordinator Area to their DPs, GOPs, and TOs as necessary to support the UFLS program, but did so more than 60 days after completion of the system studies. or The Planning Coordinator did not provide the UFLS island boundaries within its Planning Coordinator Area to their DPs, GOPs, and TOs as necessary to support the UFLS program.
R3	The Planning Coordinator identified all non-BES generation facilities per R3 to the Regional Entity, but did so more than 30 days but less than 41 days to the requesting entity.	The Planning Coordinator identified all non-BES generation facilities per R3 to the Regional Entity, but did so more than 40 days but less than 51 days to the requesting entity.	The Planning Coordinator identified all non-BES generation facilities per R3 to the Regional Entity, but did so more than 50 days but less than 61 days to the requesting entity.	The Planning Coordinator identified all non-BES generation facilities per R3 to the Regional Entity, but did so more than 60 days after the request. or The Planning Coordinator failed to identify to the Regional Entity

				all the non-BES generation facilities per R3.
R4	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program as specified in Attachment C Tables 1-3 from their PC, reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island as identified by the PC in Requirement R2.
R5	N/A	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table 2 only, the need to deviate from providing two stages of UFLS.	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the 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 appropriate table.	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load.

R6	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to set an underfrequency relay that is part of its region's UFLS program as specified in Requirement R6.
R7	N/A	N/A	The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year.	The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R7.
R8	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds. or The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds.

R9	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider or Transmission Owner did not develop its implementation plan.
R10	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with Requirement R9.
R11				The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, (or calculated from measurements made at the nearest available metering), that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.

R12	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 2, except as otherwise exempted in R15 or R18.
R13	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator's request. or The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator.
R14	N/A	N/A	The Generator Owner 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 did not fulfill the obligation of Requirement R14, Part 14.1. and did not fulfill the obligation of Requirement R14, Part 14.2.

R15	N/A	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.2.	The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1. OR did not fulfill the obligation of Requirement R15, Part 15.3.	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1. and did not fulfill the obligation of Requirement R15, Part 15.3.
R16	N/A	N/A	N/A	The Planning Coordinator in Ontario, Quebec, or the Maritimes did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required in R15.3.
R17	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner within the PC areas of New York or New England, did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R18	N/A	The Generator Owner did not fulfill the obligation of Requirement R18, Part 18.3.	The Generator Owner did not fulfill the obligation of Requirement R18; Part 18.1. OR did not fulfill the obligation of Requirement R18, Part 18.2.	The Generator Owner did not fulfill the obligation of Requirement R18, Part 18.1. and did not fulfill the obligation of Requirement R18, Part 18.2.

PRC-006-NPCC-2 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 2. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all UFLS islands in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements as part of its UFLS Assessment based on the NERC PRC Standard on UFLS:

1. The Planning Coordinator shall identify, compile and maintain a list of all existing non-nuclear generating units, in their Planning Coordinator area, in service prior to the effective date of Version 1 of the regional Standard (April, 2017 PRC-006-NPCC-1). The list must indicate generating units, if any, that have their underfrequency protections set to trip above the appropriate curve in Figure 2. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in Figure 2. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator within which the generator may operate to provide compensatory load shedding.

    2.2 In Ontario and in the Maritime provinces, the compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2 during an underfrequency event. If the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 2.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 2 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify, compile, and maintain a list of all of its existing non-nuclear generating units in service prior to the effective date of Version 1 of the regional Standard (April, 2017 PRC-006-NPCC-1). The list must indicate the Generator Owner's generating units, if any, that have their underfrequency protections set to trip above the appropriate curve in Figure 2. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in Figure 2. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 2, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 2, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution

Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment C

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW[2] or more of peak net Load shall implement a UFLS program with the following attributes:

Frequency Threshold (Hz)	Total Nominal Operating Time (s)[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[2] or more and less than 100 MW[2] of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.
2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW[2] or more and less than 50 MW[2] of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28-50	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.
2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

Guidelines and Technical Basis:

Standard PRC-006-2, 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 (MOD-027-1 - Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions) or system modeling (if variations in system response are detected under MOD-033 - Steady-State and Dynamic System Model Validation)

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

March 30, 2017

NPCC Full and General Members:

The ballot for approval of the revisions to the Quebec Variance in PRC-006-3 *Automatic Underfrequency Load Shedding* closed at 23:59 on March 24, 2017.

The results of the ballot were as follows:

Quorum: 79.59% of the Total Registered
Approval: 89.74%

One negative ballot was received without comments, therefore in accordance with the NPCC Standard Processes Manual, a recommendation for final Regional approval will be sent to the NPCC Board of Directors for consideration at their meeting on May 3, 2017.

Contingent upon the approval of the NPCC BOD, the proposal to adopt the revised variance in PRC-006-3 will be posted for a 45 day comment period by NERC, specifically related to NPCC's Standard development process. Upon receipt of any industry comments, responses to those comments will be posted on the NERC website. NERC will then submit the proposed standard, along with their endorsement, to the NERC Board of Trustees (BOT) for adoption. Upon adoption by the BOT, the standard will then be filed by NERC Legal with the FERC and applicable provincial authorities.

Voting was conducted electronically and the full ballot record may be viewed at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=123

Thank you for your participation.

Ruida Shu
Northeast Power Coordinating Council, Inc.
Senior Engineer, Reliability Standards and Criteria
Main: 212-840-1070
Direct: 917-934-7976
Fax: 212-302-2782
Email: rshu@npcc.org

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 1, Transmission Owners	**18**	**16**	**0**		**16**	**0**	**0**
Central Hudson Gas and Electric Corporation	1	1			1		
Central Maine Power Company	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Emera Maine	1						
Eversource Energy	1	1			1		
Hydro One Inc	1	1			1		
Hydro-Quebec TransEnergie	1	1			1		
Long Island Power Authority	1	1			1		
National Grid	1	1			1		
New Brunswick Power Corporation	1	1			1		
New Hampshire Transmission, LLC	1	1			1		
New York Power Authority	1	1			1		
New York State Electric & Gas Corporation	1						
Nova Scotia Power Inc.	1	1			1		
Orange and Rockland Utilities Inc	1	1			1		
Rochester Gas & Electric Corporation	1	1			1		
The United Illuminating Company	1	1			1		
Vermont Transco	1	1			1		

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 2, Reliability Coordinators	**5**	**5**	**0**		**5**	**0**	**0**
Hydro-Quebec TransEnergie	1	1			1		
Independent Electricity System Operator	1	1			1		
ISO-New England, Inc.	1	1			1		
New Brunswick Power Corporation	1	1			1		
New York Independent System Operator	1	1			1		

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 3, TDUs, Dist. And LSE	**20**	**16**	**0**		**14**	**0**	**2**
Braintree Electric Light Department	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Eversource Energy	1	1			1		
Groton Electric Light	1	1			1		
Hingham Municipal Lighting Plant	1	1			1		
Hydro One Inc	1	1			1		
Hydro Quebec Distribution	1	1			1		
Ipswich Municipal Light Department	1	1					1
Long Island Power Authority	1	1			1		
Marblehead Municipal Light Department	1	1			1		
National Grid USA	1	1			1		
New York Power Authority	1	1			1		
Orange and Rockland Utilities, Inc	1	1			1		
Princeton Municipal Light Department	1	1			1		
Shrewsbury Electric & Cable Operations	1	1			1		
Sterling Municipal Light Department	1						
Toronto Hydro Electric System Ltd.	1						
Vermont Electric Cooperative, Inc.	1						
Wakefield Municipal Gas and Light Department	1	1					1
Westfield Gas & Electric Light Department	1						

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 4, Generator Owners	**21**	**15**	**0**		**13**	**1**	**1**
Consolidated Edison Company of New York, Inc.	1	1			1		
Covanta Energy	1						
Dominion Resources, Inc.	1	1			1		
Dynegy, Inc.	1	1				1	
Entergy Nuclear Northeast, Inc	1	1			1		
Eversouce Energy	1	1			1		
Exelon Generation Company, LLC	1						
First Wind Operations & Maintenance	1						
International Power America	1						
Long Island Power Authority	1	1			1		
Massachusetts Municipal Wholesale Electric Company	1	1			1		
New York Power Authority	1	1			1		
NextEra Energy Resources, LLC	1	1			1		
NRG Energy Inc.	1	1			1		
Nova Scotia Power Inc.	1	1					1
Ontario Power Generation Inc.	1	1			1		
PSEG Fossil LLC	1						
Talen Energy Supply, LLC	1	1			1		
TransCanada	1	1			1		
Eastern Generation LLC	1						
Wheelabrator Westchester LP	1	1			1		

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 5, Marketers, Brokers, Aggragators	**13**	**10**	**0**		**9**	**0**	**1**
Brookfield Power Corporation	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Consolidated Edison Energy/Development	1	1			1		
Constellation New Energy, Inc.	1						
HQ Energy Marketing Inc.	1	1			1		
H.Q. Energy Services (U.S.) Inc.	1	1			1		
Long Island Power Authority	1						
Massachusetts Municipal Wholesale Electric Company	1	1			1		
Nalcor Energy	1	1					1
New York Power Authority	1	1			1		
Shell Energy North America	1	1			1		
Utility Services Inc.	1	1			1		
Windy Bay Power, LLC	1						

	1. Determine Quorum			2. Vote/Ballot Recording		
NPCC Registered Members	**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
	(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 6, State and Provincial Reg. and Govt. Authorities	**7**	**6**	**0**	**6**	**0**	**0**
Long Island Power Authority	1	1		1		
Maine Public Utilities Commission	1	1		1		
Massachusetts Attorney General	1	1		1		
New Hampshire Public Utilities Commission	1	1		1		
New York Power Authority	1	1		1		
New York State Department of Public Service	1	1		1		
Vermont Department of Public Service	1					

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 7, Sub Regional Rel. Councils, REs and Others	**14**	**10**	**0**		**7**	**0**	**3**
4g Technologies, LP	1						
Ascendant Energy Solutions, Inc.	1	1			1		
Energy Sector Security Consortium, Inc.	1						
ERLPhase Power Technologies	1	1			1		
International Business Machines Corporation	1						
McCoy Power Consultants, Inc.	1	1					1
Network & Security Technologies, Inc.	1	1					1
New York State Reliability Council, LLC	1	1			1		
Oxbow-Sherman Energy, LLC	1	1			1		
PLM, Inc.	1	1					1
Preti, Flaherty, Beliveau, and Pachios, LLP.	1	1			1		
Proven Compliance Solutions, Inc.	1	1			1		
SGC Engineering, LLC	1	1			1		
VIASYN, Inc.	1						

Determine Electronic Quorum

Sector	Sector Name	Total Registered	In Attendance	By Proxy	Total Represented	Sector % Attending
1	**Transmission Owners**	18	16	0	16	0.89
2	**Reliability Coordinators**	5	5	0	5	1.00
3	**TDUs, Dist. And LSE**	20	16	0	16	0.80
4	**Generator Owners**	21	15	0	15	0.71
5	**Marketers, Brokers, Aggragators**	13	10	0	10	0.77
6	**Customers- large and small**	7	6	0	6	0.86
7	**State and Provincial Reg. and Govt. Authorities**	14	10	0	10	0.71
		98	78	0	78	

Electronic Vote Quorum= at least 2/3 of the Total Registered

Quorum Present? **YES**

Determine if Motion or Item Passes

Sector	Sector Name	Total	Sector %	Affirmative		Negative		Abstain	Votes Cast	Sector has
		Registered	Attending	# of Votes	Fraction	# of Votes	Fraction	# of Votes	Total (- Abstentions)	Voted(1-Y, 0-N)
1	**Transmission Owners**	18	0.89	16	1.000	0	0.000	0	16	1
2	**Reliability Coordinators**	5	1.00	5	1.000	0	0.000	0	5	1
3	**TDUs, Dist. And LSE**	20	0.80	14	1.000	0	0.000	2	14	1
4	**Generator Owners**	21	0.71	13	0.929	1	0.071	1	14	1
5	**Marketers, Brokers, Aggragators**	13	0.77	9	1.000	0	0.000	1	9	1
6	**Customers- large and small**	7	0.86	6	1.000	0	0.000	0	6	1
7	**State and Provincial Reg. and Govt. Authorities**	14	0.71	7	1.000	0	0.000	3	7	1
	Totals	98		70	6.929	1	0.071	7	71	7

Sum of Affirmative/Number of Sectors that Voted
MUST BE AT LEAST 2/3 to pass

0.990

Did MOTION PASS?

PASS

REGIONAL STANDARDS COMMITTEE

Chairman:

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Assistant Vice President - Standards
Northeast Power Coordinating Council, Inc.
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Email: gzito@npcc.org

Co-Vice Chairman:

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Sector 1 - Transmission Owners

Hydro One Networks, Inc.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

INFORMATIONAL FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION REGARDING THE LIGHT-LOAD CASE STUDY OF THE EASTERN INTERCONNECTION

The North American Electric Reliability Corporation ("NERC") hereby submits this informational filing ("Informational Filing") to the Federal Energy Regulatory Commission ("Commission") as directed in this proceeding in Order No. 794.[1] In Order No. 794, the Commission-approved Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting) and directed NERC "to submit the results of the Eastern Interconnection Reliability Assessment Group's light-load case, using actual turbine governor response data. Additionally, the Commission direct[ed] NERC to submit a recommendation on whether further actions are warranted …. Further, the report should discuss any appropriate changes to the Interconnection Frequency Response Obligation …."[2] The *2017 Frequency Response of the Eastern Interconnection during Light Load Conditions* report ("EI Report"), attached hereto as **Attachment 1**, addresses the Commission's directive and demonstrates that the Interconnection Frequency Response Obligation ("IFRO") is adequate during light load conditions. The EI Report states that, "Based on NERC's analysis, the Interconnection Frequency Response Obligation (IFRO) under Reliability Standard BAL-003-1.1 for the Eastern Interconnection is

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

[2] *Id.* at P 84 (Order No. 794 included additional directives regarding an informational filing due July 1, 2018. NERC continues to evaluate frequency response issues in anticipation of the 2018 filing).

adequate during light-load conditions. As a result, NERC finds no impending need for immediate action but recommends that the ERO Enterprise continue its efforts to improve dynamic modeling for studying frequency response, and continue its analyses of frequency response-related matters."[3]

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[3] *2017 Frequency Response of the Eastern Interconnection during Light Load Conditions* report.

[4] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2016), to allow the inclusion of more than two persons on the service list in this proceeding.

II. CONCLUSION

Wherefore, as demonstrated in the EI Report, the IFRO is adequate during light load conditions and no further immediate action is recommended as a result of the study apart from NERC's continued analysis of frequency response related matters. NERC respectfully requests that the Commission accept this informational filing as compliant with the Commission's directive in Order No. 794.

Respectfully submitted,

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Date: June 30, 2017

cc: Official service list in Docket No. RM13-11-000

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 June 2017.

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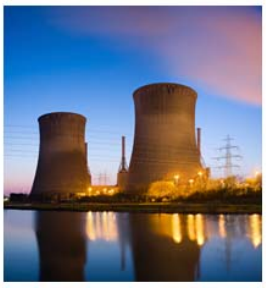
Attachment 1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2017 Frequency Response of the Eastern Interconnection during Light Load Conditions

June 30, 2017

RELIABILITY | ACCOUNTABILITY



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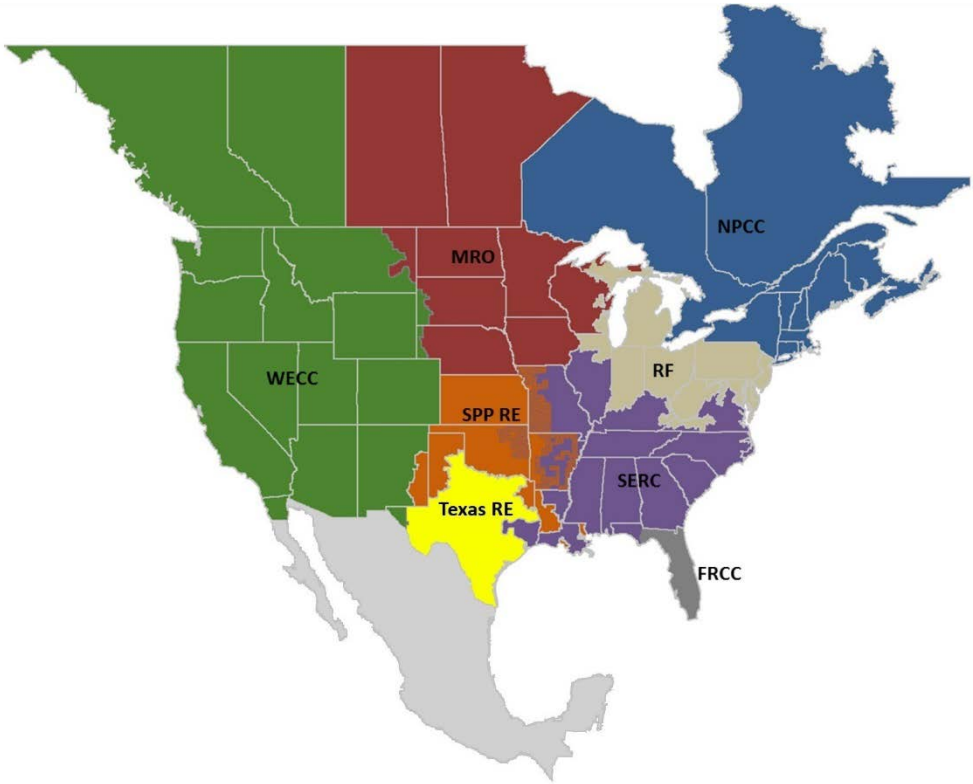
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

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



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

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

The North American bulk power system (BPS) is a complex system with thousands of interconnected elements that must be operated within a specific frequency range to continuously maintain the balance between generation and load. This is accomplished by ensuring that adequate resources are available to respond to expected (e.g., load changes) and unexpected (e.g., generation trip) imbalances that cause system frequency to deviate from the target (or scheduled) frequency of 60 Hz. Restoring frequency to its scheduled value in a timely manner during the unexpected imbalances is a critical requirement to maintain reliability. The BPS must be flexible enough to reliably operate under a variety of scenarios that require a resource mix with certain capabilities to provide ancillary services.

While the decline in Frequency Response has lessened in recent years and improvement has been observed in the Eastern Interconnection, it is important that industry and regulators understand the growing complexities of frequency control and are ready with comprehensive strategies to stay ahead of any potential problems. System planning and operations experts are anticipating higher penetrations of inverter-based resources (e.g., wind and solar) that are electronically coupled to the grid. This presents new technical challenges, including a potential reduction of frequency-responsive resources, lower system inertia levels, and greater frequency variability. These challenges are driven by several factors, including 1) the economic dispatch of least cost renewable resources, 2) an evolution of inverter technology and capabilities to provide essential reliability services, and 3) these resources are asynchronously connected to the BPS. Renewable resources are generally dispatched at maximum available power output (i.e., based on wind speed or solar irradiance) due to low variable costs. Operating at maximum power output with no headroom (Pmax ≈ Pgen) eliminates the ability of these resources to support grid frequency when an imbalance of generation and load occurs (known as an under-frequency event). New technologies (e.g., storage, inverter based power electronics, and demand response) can all contribute to Frequency Response; however, a combination of policies, incentives, and interconnection requirements in the future need further refinement to ensure the appropriate mechanisms are in place to ensure reliability.

This document provides an update on NERC's assessment of primary frequency response (PFR) for the Eastern Interconnection and responds to FERC Order No. 794 as described in the executive summary. The fundamentals of PFR are fully described in NERC's 2012 *Frequency Response Initiative Report: The Reliability Role of Frequency Response*.[1]

PFR has been identified by NERC's Operating Committee (OC) and Planning Committee (PC) as an essential reliability service (ERS) that will be affected by the changing grid characteristics of the BPS. PFR is defined as:[2]

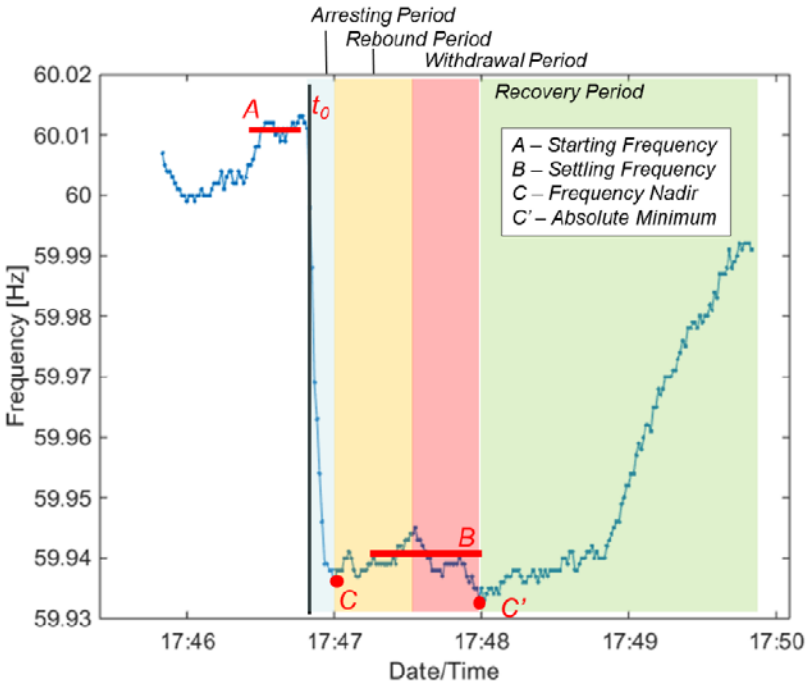
- **Actions from uncontrolled (natural) sources in response to changes in frequency:** rotational inertia (H) response from resources and load response from frequency dependent loads (e.g., motors). In addition, it can come from Primary Frequency Control.

- **Primary frequency control:** A subset of PFR actions provided by prime mover governors in an interconnection to arrest and stabilize frequency in response to frequency deviations. Primary frequency control comes from local control systems.

[1] NERC. (2012*). Frequency Response Initiative Report*. Retrieved from http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf.

[2] Reliability Guideline Primary Frequency Control. (2015, December 15). Retrieved June 29, 2017, from http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Primary_Frequency_Control_final.pdf.

PFR relates the size of the resource lost to the resulting net change in system frequency during the period in which stabilizing frequency is determined following the initiating system disturbance event as illustrated in the Figure below. Frequency response simulations provide a means of evaluating the operation of primary frequency controls following the sudden loss of resource, known as the Resource Loss Protection Criteria (RLPC)[3] to determine if primary frequency control response provided by on-line resources successfully arrests and stabilizes frequency decline prior to initiating any UFLS action to arrest further frequency decline by shedding firm customer loads.



Typical Primary Frequency Response

[3] The Resource Loss Protection Criteria is the largest generation loss defined as largest category C (N-2) event; except for the Eastern Interconnection, which uses largest event in the last 10 years. Those values were determined in the 2012 Frequency Response Initiative Report ("2012 FRI Report").

Executive Summary

This report documents NERC's evaluation of the frequency response modeling of the Eastern Interconnection (EI) to satisfy the directive set forth in Federal Energy Regulatory Commission (FERC or Commission) Order No. 794. That order directed that, no later than 15 months after implementation of Reliability Standard BAL-003-1, NERC submit an informational filing that "addresses the results and recommendations of a light load case study of the Eastern Interconnection using actual turbine governor response data."[4] As stated in the Order:

> "…the Commission directs NERC to submit the results of the ERAG's light-load case, using actual turbine governor response data. Additionally, the Commission directs NERC to submit a recommendation on whether further actions are warranted no later than 15 months after implementation of the Final Rule. Further, the report should discuss any appropriate changes to the Interconnection Frequency Response Obligation warranted by this study."[5]

The analysis used a 2017 light load dynamics base case prepared specifically for this frequency response study by using the 2016 data provided by the Eastern Interconnection Reliability Assessment Group (ERAG)/Multiregional Modeling Working Group (MMWG).

This report addresses the Commission's directive in Order No. 794 and was prepared using actual turbine governor response data, discussed in more depth below. Based on NERC's analysis, the Interconnection Frequency Response Obligation (IFRO) under Reliability Standard BAL-003-1.1 for the Eastern Interconnection is adequate during light-load conditions. As a result, NERC finds no impending need for immediate action but recommends that the ERO Enterprise continue its efforts to improve dynamic modeling for studying frequency response, and continue its analyses of frequency response-related matters. Key findings and recommendations from the study are examined in this report and summarized in this executive summary.

Key Findings and Recommendations

The following are the key findings of this study.

- **Finding 1:** Benchmarking of the 2017-LL dynamics case shows significant improvement in the data quality and fidelity of the case from those present in dynamics cases at the start of the Frequency Response Initiative in 2010. However, the case still exhibits more frequency response than actually exists during the rebound period of the response and does not yet accurately reflect response withdrawal, which is still exhibited in the Eastern Interconnection. NERC believes that the model validation and tuning of the dynamics models associated with Standard MOD-033 will further improve the light load dynamics case fidelity.

  Automatic generation control (AGC), remedial action schemes, generator protection and controls, and outer-loop plant controls should be considered to capture mid-term dynamics behavior. Mid-term dynamics analysis encompasses time periods beyond those normally used for transient stability analyses.

  - **Recommendation 1:** NERC should continue to:
    - Improve the data quality of models for conventional generation
    - Improve models of wind and inverter-based resources
    - Advance dynamics model validation methods and tuning models to actual system response
    - Refine the process to identify larger frequency response events and capture high-speed system performance data for use in model validation

[4] *Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024, at P 3 (2014).
[5] Ibid., 84.

- Work directly with software vendors to improve dynamics models of new technologies such as inverter-based resources and wind generation
- Work directly with software vendors to model plant outer-loop controls that can cause frequency response withdrawal and the capability to mimic the early stages of automatic generator control (AGC)
- Evaluate frequency response performance of the Eastern Interconnection from a forward-looking perspective for the study year 2021 Light Load Case due to the changing resource mix and the implementation of environmental regulation. This forward-looking study for the Eastern Interconnection is scheduled to be released at the end of the third quarter 2017
- Advance understanding and modeling of mid-term dynamic system behaviors that can have significant effects on overall frequency response performance.

- **Finding 2:** This analysis is the first validation of the light load base case for the recommended IFRO of the Eastern Interconnection that uses actual governor data obtained from the Generator Owners and operators through a number of surveys. NERC further completed a detailed review of governor models being used in the dynamics cases. Recommendations on changes to governor models and detailed setting data were provided to the ERAG/MMWG for incorporation in the 2016 Series of the 2017-LL dynamics base case.
  - Previous IFRO validations in the 2012 Frequency Response Initiative (FRI) Report and subsequent Frequency Response Annual Analyses had to be performed with a dynamics case modified to contain only generic governor models.
  - Two conclusions can be drawn from this analysis:
    - The 1,015 MW/0.1 HZ IFRO prescribed for the 2017 Operating Year is validated to be adequate to maintain reliability of the Eastern Interconnection for the current Resource Loss Protection Criteria (RLPC) of 4,500 MW under the modeled light load conditions. The resultant nadir for that case is 59.564 Hz, about 64 mHz above the 59.5 Hz Under-Frequency Load shedding (UFLS) set point.
    - The frequency responsiveness modeled in the 2017-LL case would have to be reduced by over 85 percent to reduce the response to the level of performance prescribed by the IFRO. This reflects the existence of sufficient margin in projected system performance versus the IFRO.
  - **Recommendation 2a**: NERC should continue working with ERAG/MMWG to annually create light load dynamics cases with actual governor data, validated against governor performance during system frequency events.
  - **Recommendation 2b**: NERC should annually validate the recommended Eastern Interconnection IFRO in the Frequency Response Annual Analysis using those dynamic light load cases.
- **Finding 3:** The Eastern Interconnection is resilient to large losses of generation resources. That is due to its size, its considerable load response, and the frequency responsiveness of the current generation fleet. The resiliency test verifies the order of magnitude of resource loss that would be required to drop interconnection frequency close to the 59.5 Hz UFLS setting. The resiliency analysis found the nadir to be at 59.6 Hz[6] for a modeled near-simultaneous resource loss of 12,200 MW.
  - **Recommendation 3:** The resiliency test should be used as a benchmark of the current generation resource fleet in the NERC's current forward-looking study of future Eastern Interconnection Frequency Response performance due to the projected changes in resource mix. That analysis focuses on projected resources using a 2021 Frequency Responsive Light Load Case.

[6] 100 mHz above the 59.5 Hz UFLS set point.

Chapter 1: Study Approach and Methods

The frequency response study performed an analysis of the Eastern Interconnection using the ERAG/MMWG 2016 series 2017-LL Base Case containing actual turbine governor response setting data collected from GOs and GOPs. This data was organized according to governor type and provided in a format compatible with the dynamic analysis software presently used by most Eastern Interconnection Planning Coordinators. Each turbine governor was classified according to its frequency response as having: 1) squelched frequency response (withdrawal) 2) frequency responsive or 3) nonresponsive. This data was then used to create a 2017-LL frequency responsive base case for the Eastern Interconnection. Each study step is defined in more detail in Figure 1.1.

A key aspect of this study was the benchmarking of the base case using model validation techniques. A significant amount of modeling improvements were made over several years before the beginning of this study. Base case model validation and detailed scrutiny of dynamics models of generation (e.g., governor models) played a major role in the improvements to the 2017-LL base case.

The purpose of model validation is evaluate the data quality and fidelity (ability to closely mimic actual system performance) to determine how closely the model measures to actual system performance. The primary means of validating a particular base case is to modify key parameters to recreate system conditions for a specific system disturbance. The practical power system conditions for the selected event should be similar to the conditions that the case is intended to represent. Generation dispatch, loads, network configuration, and operational characteristics of the case are adjusted to match the conditions that actually existed at that time. The simulation results are compared to the actual measurements of the power system that were taken during the event.

Beyond the need for validation of the steady-state behavior of the base case, it is crucial that the dynamics behavior of the system be validated as well. In that process, the behavior and parameters of the models of individual system components in the case are compared to measured behavior during an actual system event. Models to be validated and tuned include generation (including exciters, governors, power system stabilizers, current compensators, etc.), dynamic system control devices (e.g., static VAR compensators (SVCs)), flexible ac transmission system (FACTS) devices, dc terminal equipment and their controls, and dynamic loads (e.g., motors and discharge lighting).

In the benchmarking done for this study, the dynamic performance of the 2017-LL Frequency Response Base Case was compared against three significant Eastern Interconnection frequency events. In this study, the analysis concentrated on comparing system frequency response behavior of the case to the actual behavior of the interconnection during those events.

Study Steps

The following work flow was used by NERC Staff in coordination with ERAG/MMWG in preparation of this study (Figure 1.1):

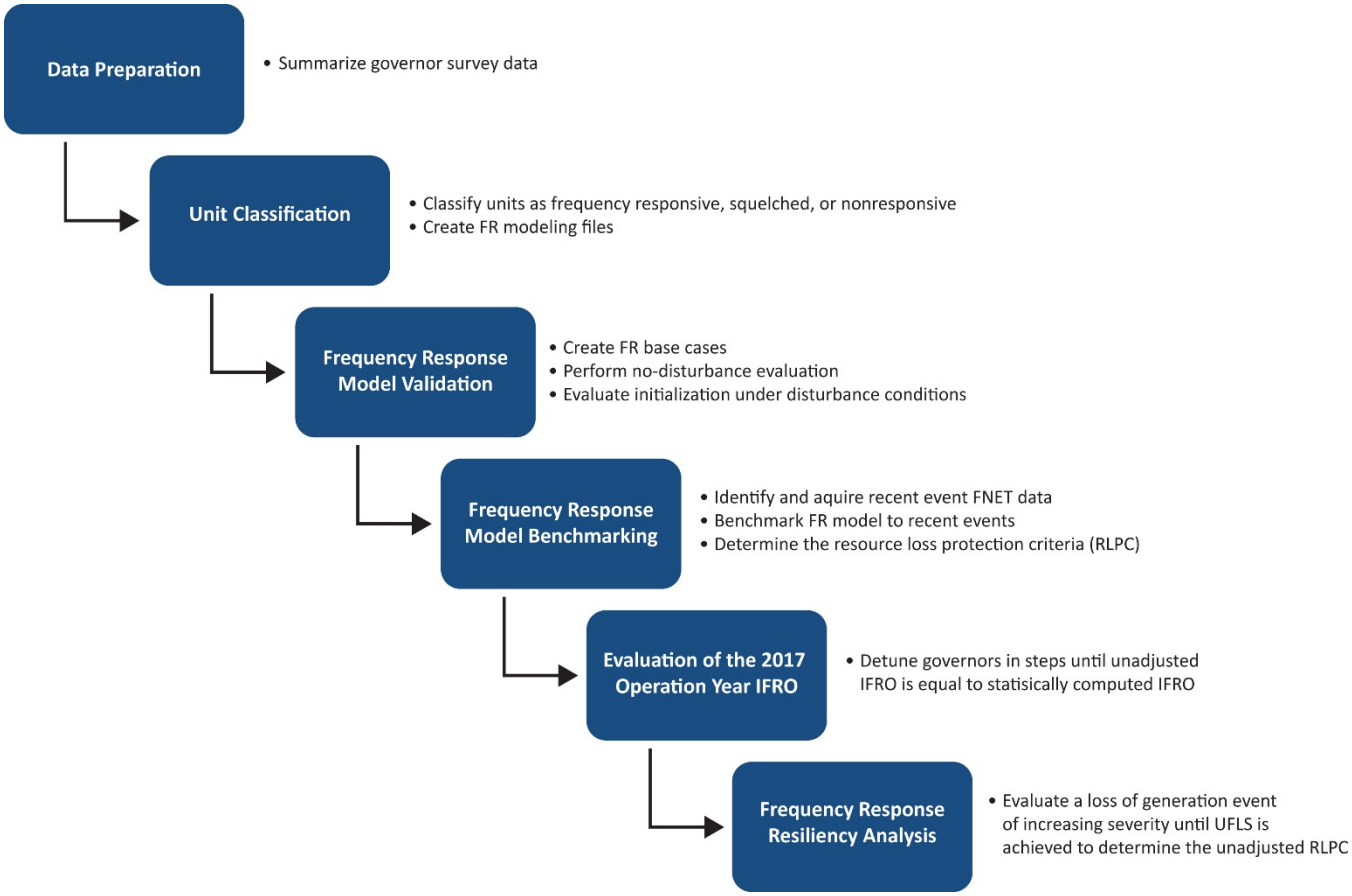


Figure 1.1: Study Overview

Data Preparation

Pursuant to the FERC directive under Order No. 794, this study was completed using actual turbine governor response modeling data. Actual turbine governor response modeling data used in this analysis was obtained in conjunction with the Frequency Response Initiative (FRI) Report published in October of 2012. The report contained data that NERC surveyed from Eastern Interconnection Generator Owners (GOs) and Generator Operators (GOPs) to identify governor modeling parameters for over 9,000 generators.

To obtain the data used, NERC issued a generator governor information and setting alert on September 9, 2010, (the alert) that recommended GOs and GOPs provide information and settings for turbine governors for all generators rated at 20 MVA or greater or plants that aggregate to a total of 75 MVA or greater net rating at the point of interconnection (i.e., wind and PV plants, etc.) connected to the Bulk Electric System (BES). A NERC alert was issued as a recommendation to industry that required reporting obligations (as specified in Section 810 of the Rules of Procedures) from industry to NERC.

The 2010 generator survey requested three types of information to capture the following unit-specific frequency responsive information:[7]

- Policies on installation and maintenance, testing procedures, and testing regularity for governors
- Unit-specific characteristics and governor settings
- Unit-specific performance information for a recent, single event. NERC sent the survey and instructions to 799 GOs and 748 GOPs in North America

A similar but conventional survey (not through the Alert Process) was conducted in 2013. From the survey results, and several years of detailed review of governor models being used in the dynamics cases, recommendations on changes to governor models and detailed setting data were provided to the ERAG/MMWG to be incorporated in the case building process. This data was further summarized and complied into dynamic data files to create the 2016 Series ERAG/MMWG 2017-LL Frequency Responsive Case.

The governor survey has been updated annually by the ERAG/MMWG by contacting entities that did not respond to the original surveys. With those annual updates, the ERAG/MMWG was able to further improve the quality of the frequency responsive cases in each successive series of cases.

Unit Classification

Each individual generating unit was assigned one of the following three possible classifications of governor response:

- **Fully Responsive:** The plant power output is fully sensitive to grid frequency in accordance with the primary control action of the governor with other plant control elements supporting the action of the governor.
- **Frequency Response Withdrawal (also referred to as squelched):** The power output is adjusted by the governor but the adjustment is overridden by the supervising action of a plant load controller that returns plant output to a scheduled value within 10–20 seconds. For several models, squelching was modeled using a proportional–integral–derivative controller (PID controller), which has a control loop feedback mechanism (controller) that continuously calculates an error as the difference between a desired set point and a measured process variable. The error is used to provide a correction based on proportional, integral, and derivative terms, respectively (sometimes denoted P, I, and D).
- **Nonresponsive:** The power output changes minimally in the first few seconds after the disturbance.

DYNAMICS BASE CASE DISCLAIMER: The 2017-LL dynamics Frequency Response Base Case is not a planning case. This assessment is based on an evaluation of frequency response using computer simulations to represent real conditions. Dispatch assumptions are made around units that would be on-line at the time of a low-load situation, and that dispatch may impact the ability of the system to provide FR.

[7] Ibid.

Chapter 2: Frequency Response Modeling

The governor modeling in the 2017-LL Base Case includes the latest available frequency responsive models, settings, and governor data. The development of a Frequency Responsive Base Case is also a coordinated effort with the Plant-level Control and Protection Modeling Task Force (PCPMTF) and NERC efforts to improve the quality of MMWG Base Case plant modeling.[8]

NERC performed a detailed examination of all of the governor models in the case, and NERC suggested replacing outdated governor models where appropriate with up-to-date versions. NERC also suggested changes to model parameters that were suspect.

Governor Models

A brief review of the most commonly used governor models and load controllers in the Eastern Interconnection is presented below.[9] These models are the TGOV1, IEESGO, IEEEG1, and GGOV1.

Table 2.1: Most-Used Governor Models in the Eastern Interconnection

Governor Model\Load Controller	Description
TGOV1	This model represents the turbine-governor droop and the main steam control valve motion and limits (T1, VMAX, and VMIN). This model has a single lead-lag block (T2/T3) that represents the time constants associated with the motion of the steam through the reheater and turbine stages. The ratio, T2/T3, equals the fraction of the turbine power that is developed by the high-pressure turbine stage and T3 is the reheater time constant.
IEESGO	This model is slightly more detailed than the TGOV1 model. In this case, droop is affected by the gain K1 (equivalent to 1/R in the TGOV1 model) and two turbine fractions are introduced (K2 and K3) to represent different stages in the steam turbine.
IEEEG1	This is the recommended model for steam turbines.[10] The IEEEG1 model includes the rate limits on the main control valve (Uo and Uc) as well as four steam stages and the ability to model cross-compound units.

[8] As part of its Modeling Improvements Initiative, NERC formed the Plant-level Control and Protection Modeling Task Force (PCPMTF) to study the effects of plant-level turbine and boiler control and protection systems models used within interconnection wide modeling cases in representing the actual machine and facilities in order to obtain realistic results from simulation outputs. The PCPMTF consist of turbine manufacturers, Generators Owners, Generator Operators, and the North American Generator Forum (NAGF), subject matter experts in power system dynamics and control, as well as stability simulation software vendors. PCPMTF collaborated on identification of models and modeling practices for plant-level turbine protection and control functions in order to identify gaps in obtaining accurate stability study results.

[9] *Dynamic Models for Turbine-Governors in Power System Studies* (Rep.). (2013, January). Retrieved June 29, 2017, from http://sites.ieee.org/fw-pes/files/2013/01/PES_TR1.pdf.

[10] *Dynamic Models for Steam and Hydro Turbines in Power System Studies* (Vol. 92, pp. 1904-1915, Rep. No. 6). (1973). IEEE Power Engineering Society.

Table 2.1: Most-Used Governor Models in the Eastern Interconnection	
Governor Model\Load Controller	**Description**
LCBF1	This model was developed in the WECC for use with this and other turbine models. The LCFB1 model is a simple representation of an outer-loop MW controller. This model has been shown to be effective in capturing the behavior of large steam turbine generators that are operated on outer-loop MW control. LCFB1 model can be used with any turbine-governor model, including the IEEEG1 and the TGOV5 models. The IEEEG1 model, in combination with the LCFB1 model can be used for large interconnected grid simulations when looking at relatively small frequency deviations (i.e., in the range of +/- 0.5 percent change in frequency).[11] The LCBF1 model is needed to represent outer-loop, plant-level controls that return the plant output to a load reference value for the time frame being studied.
GGOV1	This model was developed as a general purpose turbine-governor model to be used for dynamic simulation studies.[12] The model enforces the maximum output limit by controlling load levels between 70 and 100 percent through acceleration and temperature limit controllers. The temperature limit controller is one of several that can override the simple speed/power governor function; it is singled out for consideration because it is important in grid studies.
TGOV3	The TGOV3 model is the IEEEG1 model augmented with the addition of a simple representation of the intercept valve actuator (T5) and the intercept valve fast-closing characteristics (TI, TA, TB, and TC). The nonlinear valve position versus steam flow characteristics is also represented in this model.

In this study, most of the governors are set to a common droop setting of five percent while a few are set at other values. This is a relatively standard speed regulation setting for turbine governors for synchronous generating resources.[13] A five percent change in speed (0.05*3,600 = 180 RPM) will result in the turbine governor moving valve positions across its full capability range (e.g., 100 percent).

[11] Power System Dynamic Performance Committee, Power System Stability Subcommittee and Task force on Turbine-Governor Modelling, "Dynamic Models for Turbine-Governors in Power System Studies," PESTRI , Jan 2013.
[12] Ibid.
[13] 2012 FRI Report.

Governor Modeling Summary

A total of 9,007 generation units are modeled explicitly in the 2017-LL Base Case. There are 3,619 units dispatched on-line and the remaining 5,488 units are off-line in the case. For the on-line generation, 62 percent of the dispatched generators (2,640) are modeled without governors and are therefore non-frequency responsive. The remaining 38 percent of the on-line dispatched generators (979) are frequency responsive as shown in Figure 2.1.

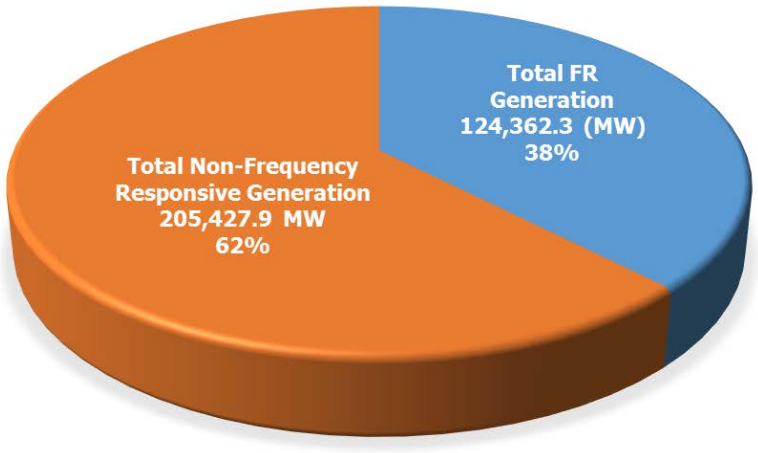


Figure 2.1: Frequency Responsive Modeling Summary

Figure 2.2 summarizes the governor modeling for the on-line dispatched generation capacity by governor type and groupings for similar types of governors in each category. These groupings are: IEEEG1 includes 143 IEEEG1s, 29 IEEEG2s, and 19 IEEEG3s; TGOV1 includes 137 TGOV1s, 3 TGOV2s, and 1 TGOV3. Governors with very small percentages not explicitly shown are grouped with one of the other categories below.

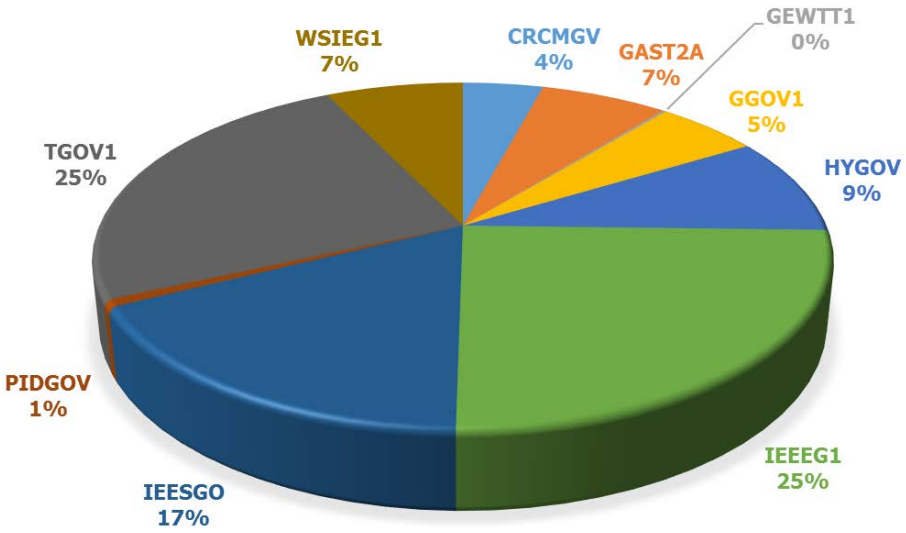


Figure 2.2: 2017-LL Dispatched Generation by Governor Type

Table 2.1 further summarize the governor modeling for the on-line dispatched generation and the corresponding available capacity in MW.

Table 2.1: Frequency Response On-line Governor Modeling (MW) by Type			
Governors	**Total Dispatched P_{Gen} (MW)**	**Total Headroom P_{Gen} (MW)**	**Squelched MW**
CRCMGV	5,177	3,753	0
GAST2A	8,229	887	0
GEWTT1	223	829	0
GGOV1	6,698	3,002	0
HYGOV	11,270	2,362	0
IEEEG1	30,903	14,834	14,694
IEESGO	21,564	6,921	9,590
PIDGOV	816	188	0
TGOV1	30,611	14,143	11,164
WSIEG1	8,872	3,155	1,074
Total Frequency Response Gen. (MW)	**124,362**	**50,074**	**36,522**
Total Gen. w/No GOV	**205,428**		
Total Gen. (MW)	**329,790**		

Only about 38 percent of the total generation modeled in the case is modeled as being frequency responsive. At the light-load level modeling in the 2017-LL case, about 35 percent of the frequency responsive capacity that is on-line is not fully loaded, providing about 50,000 MW of "headroom" to allow response to frequency events.

Additional detail on the generation composition and its modeling are available in Appendices A and B.

Chapter 3: Model Validation and Base Case Benchmarking

Model validation and benchmarking are required to assure that cases provide an accurate representation of system performance. Model validation assures that unperturbed dynamic solutions are within defined tolerances for all variables. An accurate model that initializes and solves within recommended tolerances does not mean it will necessarily produce simulation results that are representative of reality. Therefore, prior to performing any studies, the 2017-LL case was benchmarked to three known system events. Previously, NERC had been benchmarking against the 2007 Eastern Interconnection Frequency Excursion (also known as the Rockport Event). However, two more recent frequency events were selected for benchmarking because the characteristics of the interconnection's frequency response may have changed over the last 10 years. Benchmarking assures that all frequency response measures of time and frequency are approximately the same as the observed values during an actual event. The simulation and actual event frequency response parameters identified in Figure 3.1 are compared with one another, and the mismatch obtained from this comparison is than compared to the metric success value.

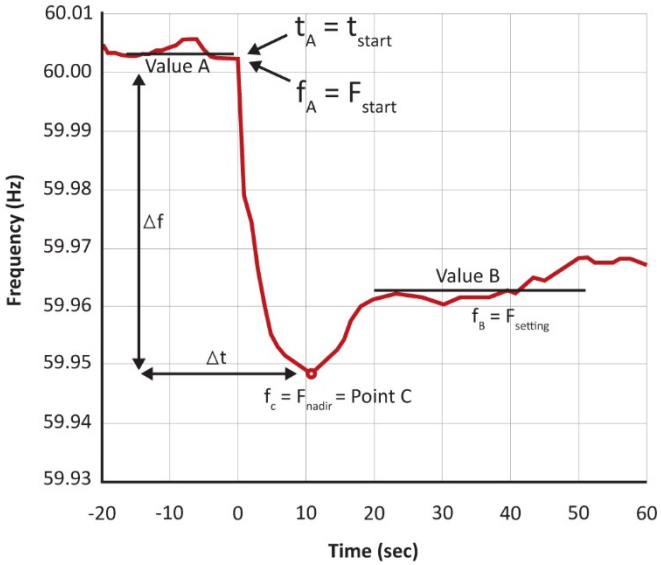


Figure 3.1: Typical Frequency Response Plot

The metric success value is used as a guidance to confirm if we have a valid performance that falls within a set of tolerance. Benchmarking was performed for the 2017-LL case by comparing overall mismatch of the frequency nadir[14] (f_C), settling frequency[15] (f_B), net frequency change (delta frequency), and rate of change of frequency (RoCoF) from the starting frequency[16] (f_A) to the nadir from the FNET data. Where most of the mismatches are equal to or less than the metric success value, the simulation is said to benchmark very well to the actual event provided by FNET data.

[14] Described as Point C in Standard BAL-003.1, the actual nadir between T=0 and T=20 seconds.
[15] Described as Value B in Standard BAL-003.1, calculated as the average frequency from T=20 to T=52 seconds.
[16] Described as Value A in Standard BAL-003.1, calculated as the average frequency from T=-1 to T=-16 seconds.

For purposes of this analysis, RoCoF is defined as:

$$RoCoF = \frac{\Delta f}{\Delta t}$$

Where:

- RoCoF is the Rate of Change of Frequency
- Δf is the Change in frequency from the starting frequency (f_A or Value A) to the nadir (f_C or Point C)
- Δt is the Time in seconds from t_{start} (t_A or T=0) to the time of the nadir (t_C)

The three frequency events used for benchmarking are listed below. Tables have been constructed to summarize the benchmarking results for each of the following frequency events for the 2017-LL Case.

- May 25, 2014: Millstone 2 (870 MW) and Millstone 3 (1,233 MW loss)
- April 7, 2015: Calvert Cliffs 1 & 2 tripped at 1,779 MW loss)
- August 4, 2007: Eastern Interconnection Frequency Excursion(also known as the Rockport event) (4,457 MW loss)

Rockport August 4, 2007, Event and 2017-LL Case Benchmarking.

Figure 3.2 and Table 3.1 document the benchmarking for the 2017-LL case and shows that it meets most of the success metric values. The settling Value B is above the settling point for the Rockport Event due to improvements in the operation of generation in the Eastern Interconnection and to a very small extent it is impacted by load response modeling.

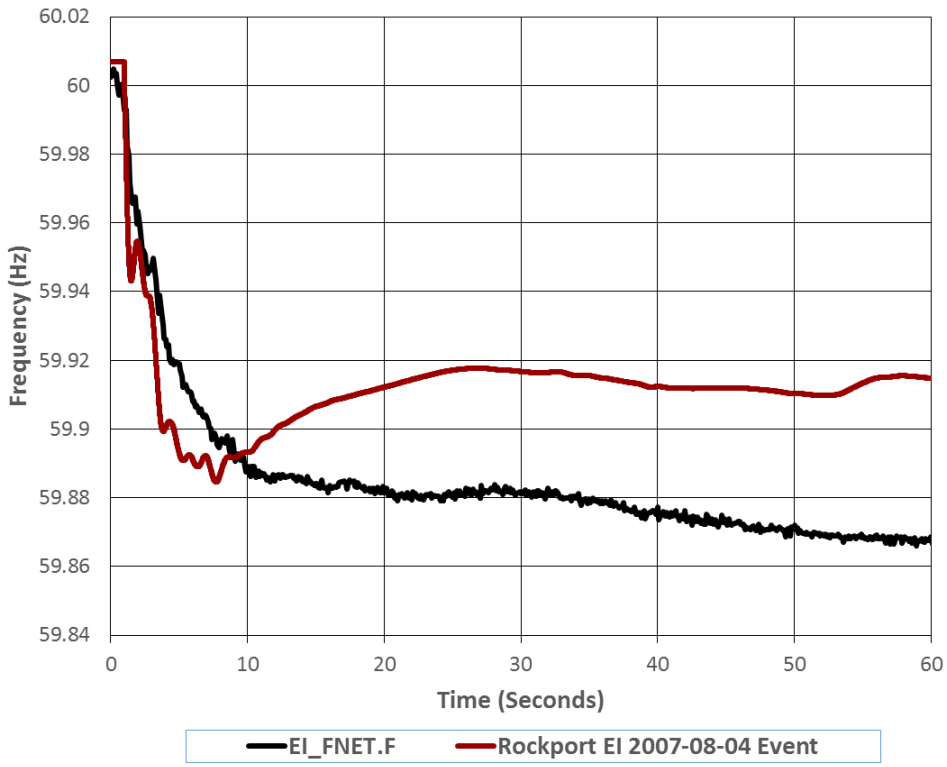


Figure 3.2: Eastern Interconnection August 4, 2007, Frequency Benchmark 2017-LL

Table 3.1: Rockport August 4, 2007, Benchmark (AEP)				
	FNET(Grid/Eye) Measurement	PSS/E Base Case	Mismatch	Metric Success Value
Starting Frequency f_A (Hz) (Value A)	60.069	60.069	0.000	0.01
Starting Time t_A	0.0	0.0	0.000	0.100
Frequency nadir f_c (Hz) (Point C)	59.880	59.880	0.000	0.010
Time of nadir t_C	10.2	7.8	2.442	1.000
Settling frequency f_B (Hz) (Value B)	59.880	59.914	-0.034	0.010
Settling Time t_B	30.0	30.0	0.000	1.000
Delta Frequency (mHz/s)	189.000	189.000	0.000	5.000
Rate of Change of Frequency RoCoF (mHz/s)	18.529	24.362	-5.833	±10.000
Frequency Response Measure (FRM) (MW/0.1Hz)	3,546.1	4,644.0	-1,097.0	N/A

Calvert Cliffs April 7, 2015 DC Event and 2017-LL Case Benchmarking

Figure 3.3 and Table 3.2 document the benchmarking for the 2017-LL case and show that it sufficiently benchmarks to the loss of Calvert Cliffs April 7, 2015, DC event. The RoCoF for the Calvert Cliffs event does not meet some of the success metrics due to details of the actual outage that are difficult to mimic in the 2017 system model. Even so, the 2017-LL Model provides a more conservative estimate of the RoCoF.

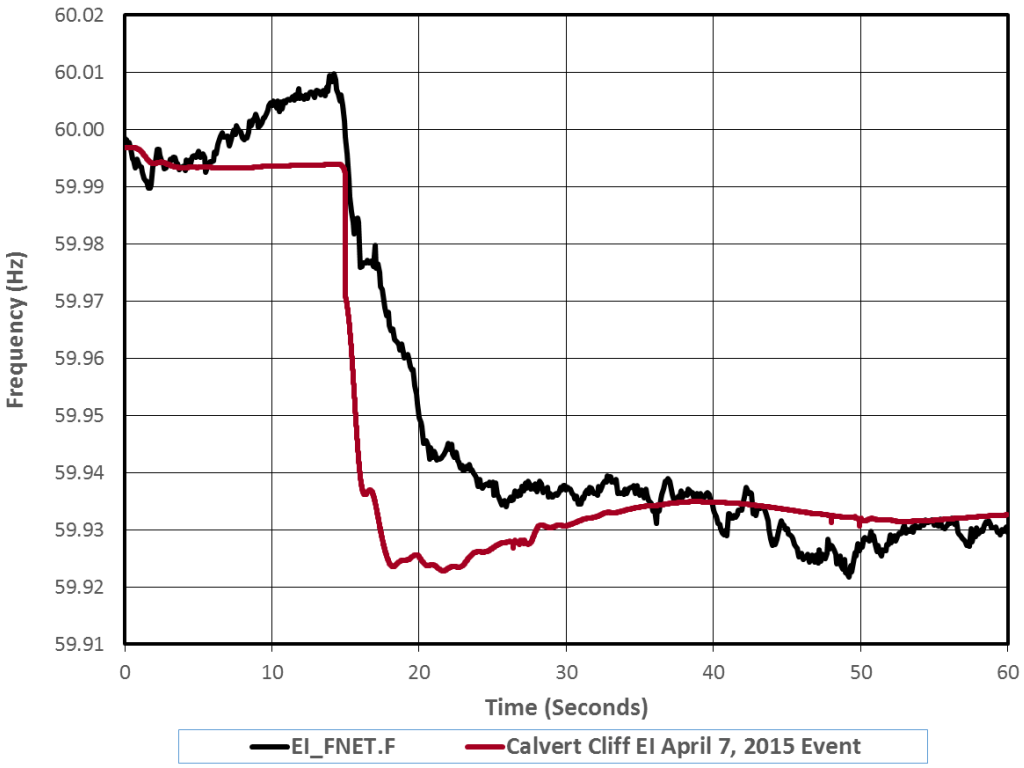


Figure 3.3: Calvert Cliffs April 7, 2015 Event FNET Benchmark (PJM) 2017-LL

Table 3.2: Calvert Cliffs April 7, 2015, Benchmark (PJM)

	FNET(Grid/Eye) Measurement	PSS/E Base Case	Mismatch	Metric Success Value
Starting Frequency f_A (Hz) (Value A)	59.999	59.993	0.006	0.010
Starting Time t_A	15.0	14.975	0.025	0.100
Frequency nadir f_c (Hz) (Point C)	59.945	59.923	0.022	0.010
Time of nadir t_C	25.9	21.6	4.300	1.000
Settling frequency f_B (Hz) (Value B)	59.934	59.931	0.003	0.010
Settling Time t_B	40.0	40.0	0.000	1.000
Delta Frequency (mHz/s)	53.400	70.400	-17.000	5.000
Rate of Change of frequency RoCoF (mHz/s)	4.904	10.626	-5.723	±10.000
Frequency Response Measure (FRM) (MW/0.1Hz)	2,869.4	2,578.3	291.1	N/A

Millstone May 25, 2014, Event and 2017-LL Case Benchmarking

Figure 3.4 and Table 3.3 document the benchmarking for the Base Case and shows that it meets most of the success metrics. The settling Value B is above the settling point for the Millstone Event due to improvements in

the operation of generation in the Eastern Interconnection and to a very small extent due to frequency response load modeling.

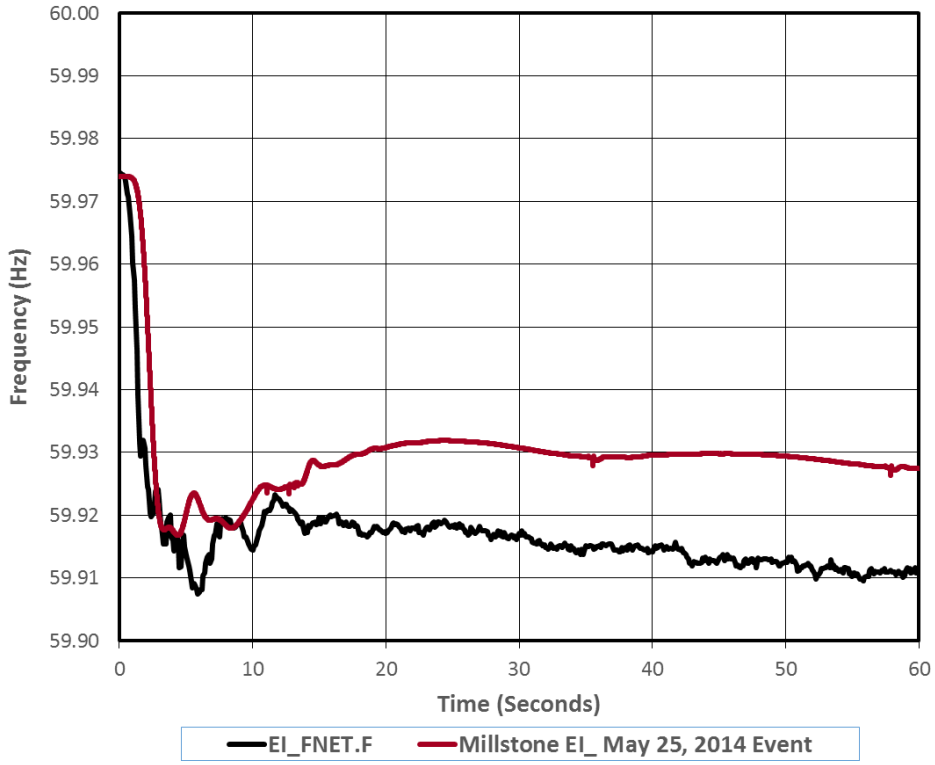


Figure 3.4: Millstone May 25, 2014, Event FNET Benchmark 2017

Table 3.3: Millstone May 25, 2014 Benchmark (ISO-NE)

	FNET(Grid/Eye) Measurement	PSS/E Base Case	Mismatch	Metric Success Value
Starting Frequency f_A (Hz) (Value A)	59.974	59.974	0.000	0.010
Starting Time t_A	0.0	0.000	0.000	0.100
Frequency nadir f_c (Hz) (Point C)	59.907	59.910	-0.003	0.010
Time of Nadir t_C	5.9	4.429	1.471	1.000
Settling frequency f_B (Hz) (Value B)	59.915	59.930	-0.015	0.010
Settling Time t_B	20.0	19.770	0.230	1.000
Delta Frequency (mHz/s)	67.000	64.000	3.000	5.000
Rate of Change of Frequency RoCoF (mHz/s)	11.356	14.450	-3.094	±10.000
Frequency Response Measure (FRM) (MW/0.1Hz)	2,163.2	2,802.3	-639.1	N/A

Benchmarking Findings and Recommendations

Finding 1: Benchmarking of the 2017-LL dynamics case shows significant improvement in the data quality and fidelity of the case from those present in dynamics cases at the start of the Frequency Response Initiative in 2010. However, the case still exhibits more frequency response than actually exists during the rebound period of the response and does not yet accurately reflect response withdrawal, which is still exhibited in the Eastern Interconnection. NERC believes that the model validation and tuning of the dynamics models associated with Standard MOD-033 will further improve the light load dynamics case fidelity.

Automatic generation control (AGC), remedial action schemes, generator protection and controls, and outer-loop plant controls should be considered to capture mid-term dynamics behavior. Mid-term dynamics analysis encompasses time periods beyond those normally used for transient stability analyses.

Recommendation 1: NERC should continue to:

- Improve the data quality of models for conventional generation
- Improve models of wind and inverter-based resources
- Advance dynamics model validation methods and tuning models to actual system response
- Refine the process to identify larger frequency response events and capture high-speed system performance data for use in model validation
- Work directly with software vendors to improve dynamics models of new technologies such as inverter-based resources and wind generation
- Work directly with software vendors to model plant outer-loop controls that can cause frequency response withdrawal and the capability to mimic the early stages of automatic generator control (AGC)
- Evaluate frequency response performance of the Eastern Interconnection from a forward-looking perspective for the study year 2021 Light Load Case due to the changing resource mix and the implementation of environmental regulation. This forward-looking study for the Eastern Interconnection is scheduled to be released at the end of the third quarter 2017
- Advance understanding and modeling of mid-term dynamic system behaviors that can have significant effects on overall frequency response performance.

Chapter 4: Evaluation of 2017 Operating Year IFRO

This study performed an evaluation of the 2017 IFRO for the Eastern Interconnection determined in the 2016 Frequency Response Annual Analysis (FRAA) against the new 2017-LL Base Case. The purpose of this analysis is to determine that if the prescribed IFRO is met, the response will be adequate to prevent activation of the 59.5 Hz Under-Frequency Load Shedding (UFLS) settings[17] of the Eastern Interconnection. UFLS is intended to be a safety net to prevent system collapse from severe contingencies and is thus the only criteria considered in this evaluation. Conceptually, it is assumed that this safety net will not be violated for any expected generation loss event. The following IFRO formula used for this analysis omits all adjustments during the evaluation of the 2017-LL IFRO.

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

$$MDF = DF_{Base}$$

$$IFRO = \frac{RLPC}{MDF}$$

Where:

- DF_{Base} is the base delta frequency.
- F_{Start} is the starting frequency determined by the statistical analysis. The starting frequency for the calculation of IFRO is the frequency calculated at five percent of the lower tail of samples from the statistical analysis.
- UFLS is the highest trip set point for the Eastern Interconnection.
- MDF is the maximum allowable delta frequency
- RLPC is the resource loss protection criteria
- IFRO is the interconnection frequency response obligation.

IFRO Evaluation Method

The method used for performing this evaluation was to detune[18] the governor performance in the 2017-LL base case in successive steps until it matched the 2017 Operating Year IFRO of 1,015 MW/0.1 Hz for loss of the RLPC of 4,500 MW. For this study, detuning was accomplished by disabling governors. The resulting nadir was than compared to 59.5Hz UFLS which is the Eastern Interconnection UFLS set point.

For the 2017-LL case, this was achieved after 85 percent of frequency responsive generators were detuned (switched off-line) as shown in the Detune #5 scenario of Table 3.3. The

Tables 4.1–4.3 and Figures 4.1–4.3 describe each detune steps labeled as Detune #3–Detune #5. Detuning stages #1 and #2 were omitted from this report because it was clear that the UFLS was not approached with these initials stages. We begin to observe significant change in the nadir starting with detune #3 as shown in Figure 4.1 and Table 4.1

[17] The highest UFLS set point in the Eastern Interconnection is 59.7 Hz in FRCC, while the prevalent highest set point in the rest of that interconnection is 59.5 Hz. The FRCC 59.7 Hz first UFLS step is based on internal stability concerns and preventing the Florida peninsula from separation from the rest of the interconnection. The FRCC concluded that the IFRO starting point of 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation for an interconnection resource loss event than for an internal FRCC event.

[18] Detuning is a process of removing or reducing the frequency response capability for a given generation resource by changing the associated governor frequency response parameters, or by disabling the governor.

Table 4.1: Detune #3 (MW of Frequency Responsive Generation Removed)		
Detuned Governors	**Detuned Responsive Gen MW by Gov Type**	**Percent of Total Gen Dispatched in Case**
IEEEG1	30,903	24.8%
PIDGOV	816	0.7%
TGOV1	30,611	24.6%
Detune #3	**62,330**	**50.1%**

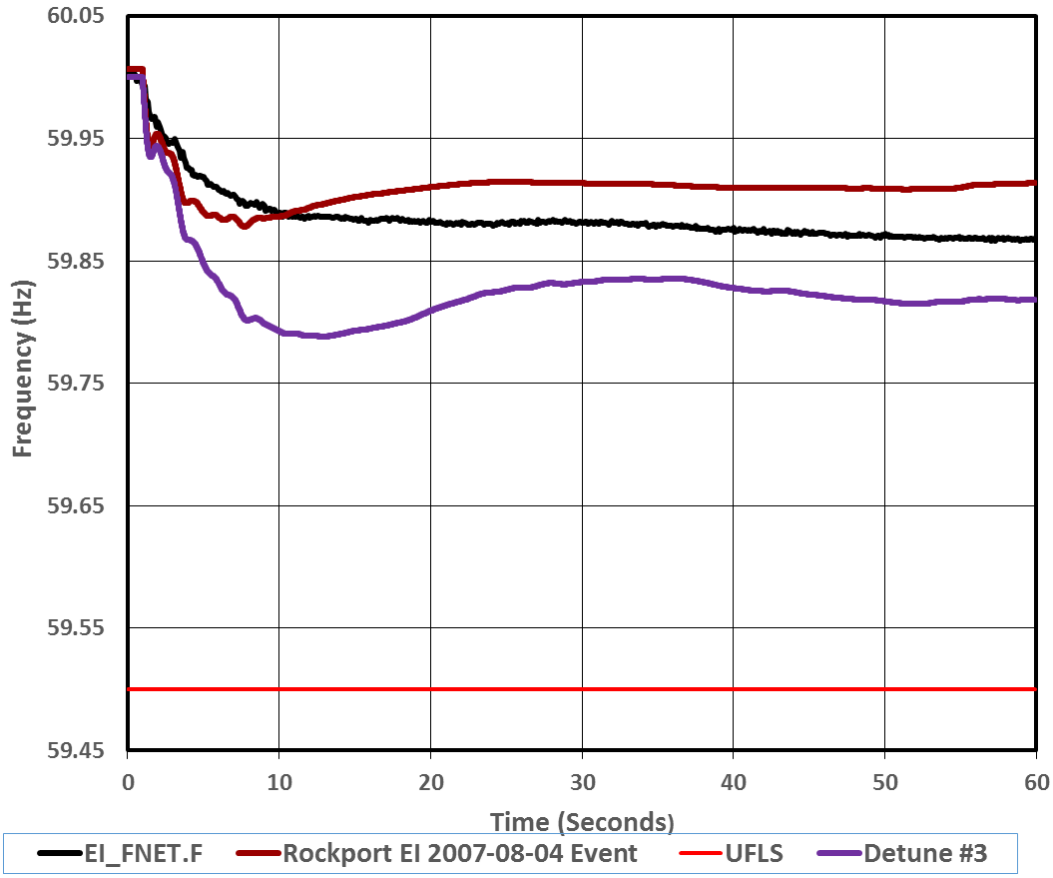


Figure 4.1: Plot for Detune #3 Scenario

Table 4.2: Detune #4 (MW of Frequency Responsive Generation Removed)		
Detune Governors	**Detuned Responsive Gen MW by Gov Type**	**Percent of Total Gen Dispatched in Case**
GGOV1	6,698.0	5.4%
IEEEG1	30,903	24.8%
IEESGO	21,564	17.3%
PIDGOV	816	0.7%
TGOV1	30,611	24.6%
Detune #4	**90,592**	**72.8%**

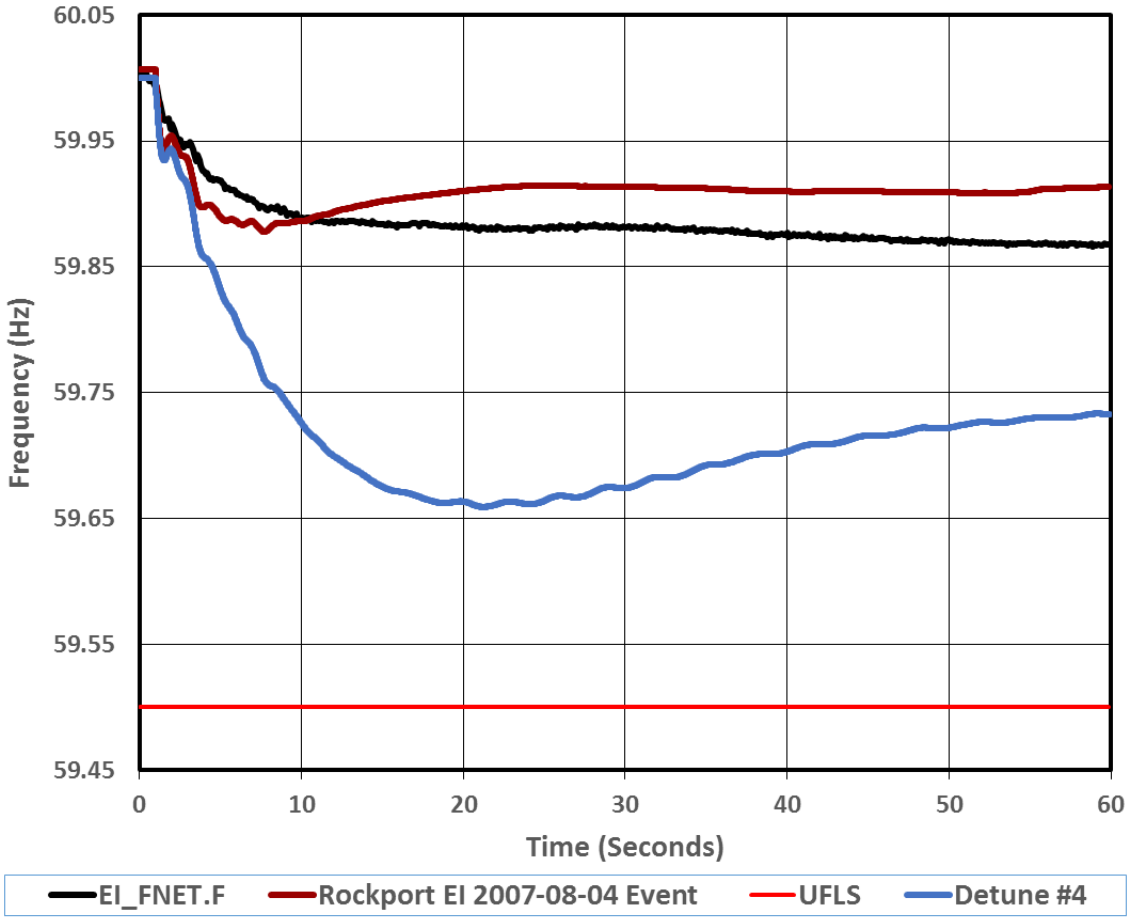


Figure 4.2: Plot for Detune #4 Scenario

Table 4.3: Detune #5 (MW of Frequency Response Generation Removed)		
Detuned Governors	**Detuned Responsive Gen MW by Gov Type**	**Percent of Total Gen Dispatched in Case**
CRCMGV	5,177	4.2%
GAST2A	3,014	2.4%
GGOV1	6,698	5.4%
IEEEG1	30,903	24.8%
IEESGO	21,564	17.3%
PIDGOV	816	0.7%
TGOV1	30,611	24.6%
WSIEG1	8,872	7.1%
Summary	107,655	86.5%

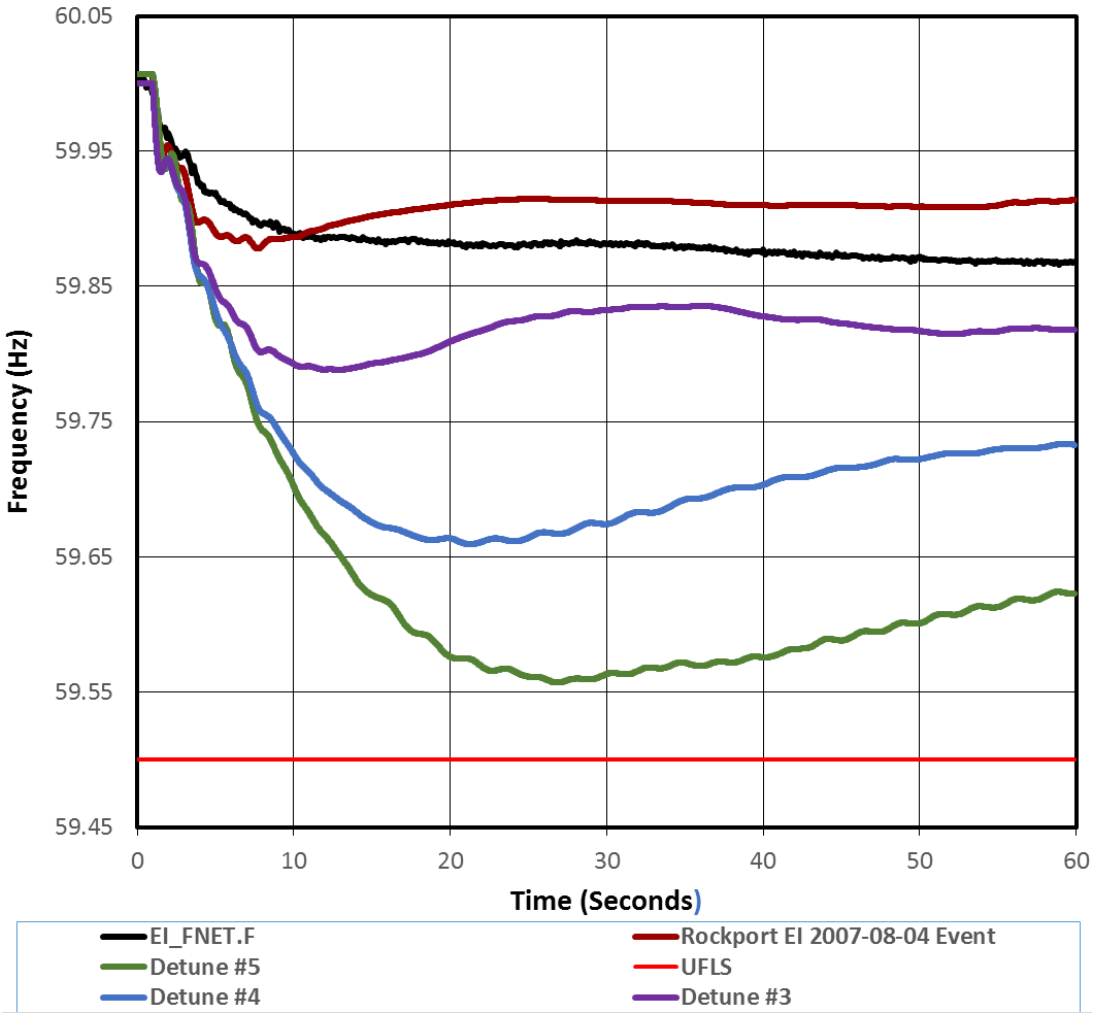


Figure 4.3: Plot for Detune #5 Scenario

IFRO Evaluation Findings and Recommendations

Finding 2: This analysis is the first validation of the recommended IFRO of the Eastern Interconnection using actual governor data in the light load base case. This was the result of incorporating actual governor response data and modeling parameters obtained from the generator owners and operators through a number of surveys, and NERC's detailed review of governor models being used in the dynamics cases. Recommendations on changes to governor models and detailed setting data were provided to the ERAG/MMWG to be incorporated in the building process for the 2017-LL Light Load dynamics base case.

Previous IFRO validations in the 2012 FRI report and subsequent Frequency Response Annual Analyses had to be performed with a dynamics case modified to contain only generic governor models.

Two conclusions can be drawn from this analysis:

a. The 1,015 MW/0.1 HZ IFRO prescribed for the 2017 Operating Year is validated to be adequate to maintain reliability of the Eastern Interconnection for the RLPC of 4,500 under the modeled light load conditions. The resultant nadir for that case is 59.564 Hz, about 64 mHz above the 59.5 Hz UFLS set point.
b. The frequency responsiveness modeled in the 2017-LL case would have to be reduced by over 85 percent to reduce the response to the level of performance prescribed by the IFRO. This reflects the existence of sufficient margin in projected system performance versus the IFRO.

Recommendation 2a: NERC should continue working with ERAG/MMWG to annually create light load dynamics cases with actual governor data, validated against governor performance during system frequency events.

Recommendation 2b: NERC should annually validate the recommended Eastern Interconnection IFRO in the Frequency Response Annual Analysis reports using those dynamic light load cases.

Chapter 5: Frequency Response Resiliency Analysis

The frequency response resiliency test is an evaluation of system performance to determine the largest event that could cause the frequency nadir to reach UFLS set point. The resiliency analysis was performed by simulating generation loss events beginning with the benchmark events Rockport, Calvert Cliff, Millstone and adding additional generation loss events until the nadir approximates the 59.5 Hz UFLS set point. The inherent 2017-LL case frequency response measures for the interconnection were all above 2,500 MW/0.1 HZ, and matched well with the frequency response measured for the actual benchmarking events.

For 2017-LL case resiliency analysis, the nadir was found to be 59.6 Hz for a modeled generation loss of 12,200 MW and this is shown in Figure 5.1. Such a loss of generation resources in the Eastern Interconnection is greater than any generation loss experience to-date in the Eastern Interconnection, except during the 2003 blackout within the area that blacked out. The near-simultaneous generation loss 12,200 MW is almost three times the RLPC of 4,500 MW used to determine the IFRO for the interconnection, and the resultant nadir remains 100 mHz above the 59.5 Hz UFLS set point.

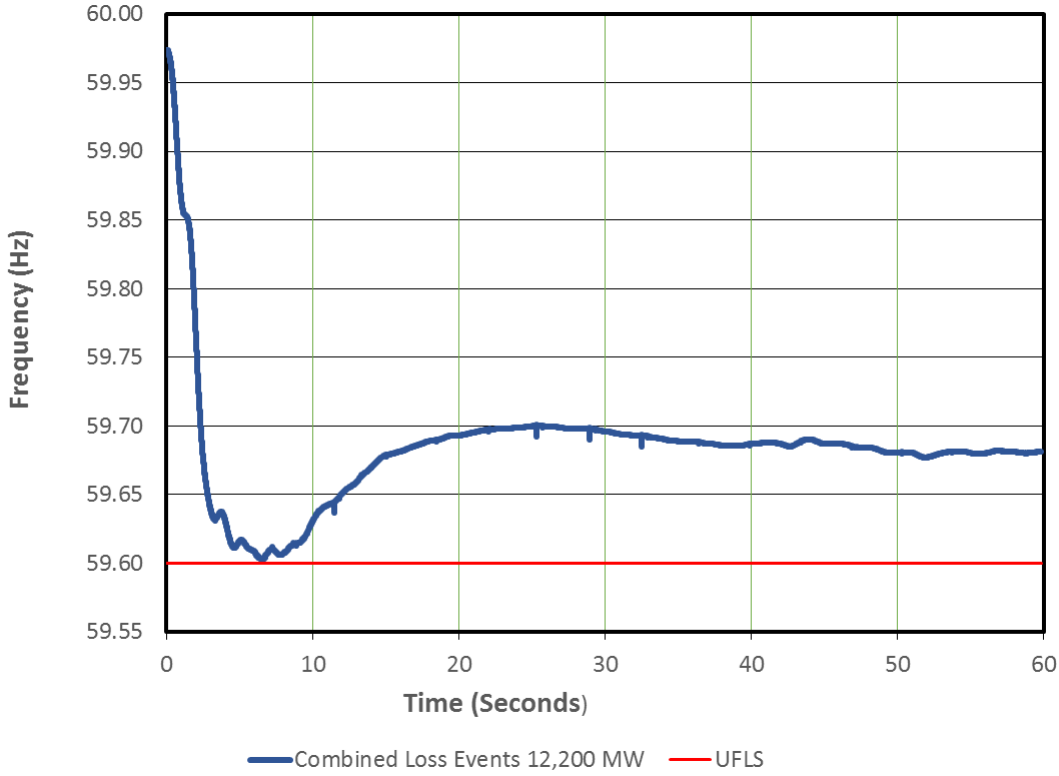


Figure 5.1: Eastern Interconnection Resiliency for 12,200 MW Resource Loss

The near-simultaneous resource calculated in this analysis has no direct relationship on the Capacity Margin of the Eastern Interconnection in the Long-Term Reliability Assessments. Capacity Margin is an expression of capacity reserves above the resources necessary to serve demand, whereas this resource loss provides a gauge of how large a resource loss can be sustained in a single disturbance.

IFRO Resiliency Analysis Findings and Recommendations

Finding 3: The Eastern Interconnection is resilient to large losses of generation resources. That is due to its size, its considerable load response, and the frequency responsiveness of the current generation fleet. The resiliency test verifies the order of magnitude of resource loss that would be required to drop interconnection frequency close to the 59.5 Hz UFLS setting. The resiliency analysis found the nadir to be at 59.6 Hz[19] for a modeled near-simultaneous resource loss of 12,200 MW.

Recommendation 3: The resiliency test should be used as a benchmark of the current generation resource fleet in the NERC's current forward-looking study of future Eastern Interconnection frequency response performance due to the projected changes in resource mix. That analysis focuses on projected resources using a 2021 Light Load Case.

[19] 100 mHz above the 59.5 Hz UFLS set point.

Appendix A: Base Case Headroom Analysis

Frequency Response Headroom Analysis

Droop and available headroom (Pmax – Pgen) for dispatched generation will determine generator frequency responsiveness. Headroom allows a generator to instantaneously increase its output to respond to system disturbances. Where there is no headroom (Pmax ≈ Pgen), there is no Frequency response even if the governors are set to respond.

Key Definitions

The headroom definition is illustrated in Figure A.1.

- P_{max}: Maximum power output capability
- P_{gen}: Portion of maximum power output dispatched
- P_{min}: Minimum power output capability
- Headroom: The difference between the maximum available power (Pmax) and the dispatched power output (Pgen).

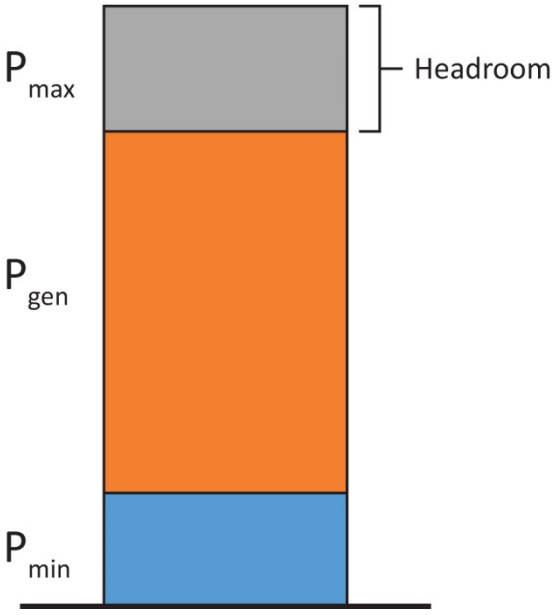


Figure A.1: Dispatched Generation Headroom

Droop is the amount of speed (or frequency) change that is necessary to cause the main prime mover control mechanism to move from fully closed to fully open. In general, the percent movement of the main prime mover control mechanism can be calculated as the speed change (in percent) divided by the per unit droop.[20] A governor tuned with speed droop will open the control valve a specified amount for a given disturbance. This is accomplished by using feedback from the main prime mover control mechanism (valve, gate, servomotor, etc.) If a one percent change in speed occurs, the main control mechanism must move enough to cause the feedback through the droop element to cancel this speed change. Thus, for a one percent speed change, the percent movement of the main control mechanism will be the reciprocal of the droop (i.e. if the droop is five percent the

[20] WECC Tutorial on Speed Governors, February 1998; Principal Investigators: Hoa D. Vu & J. C. Agee

movement will be (1/.05) = 20). Most governors for frequency responsive generation in the 2017-LL case have a five percent droop setting.

Figures A.2–A.5 document the distribution of headroom for the 2017-LL Frequency Response Case.

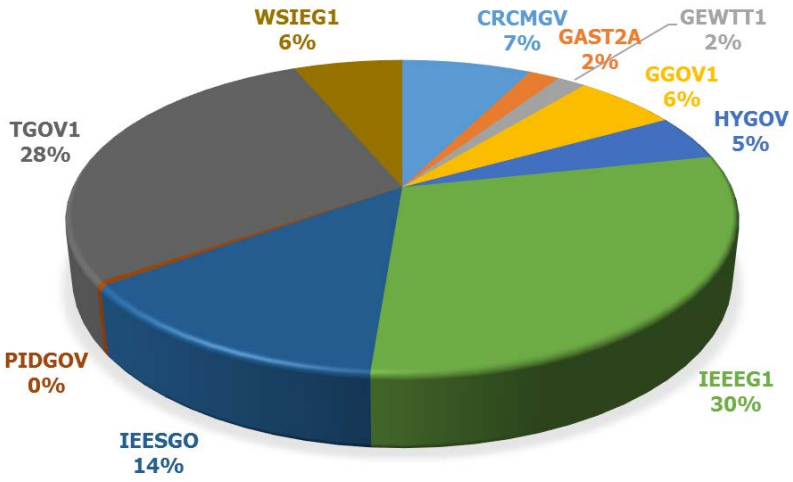


Figure A.2: 2017-LL Headroom Distribution Percent by Governor Type

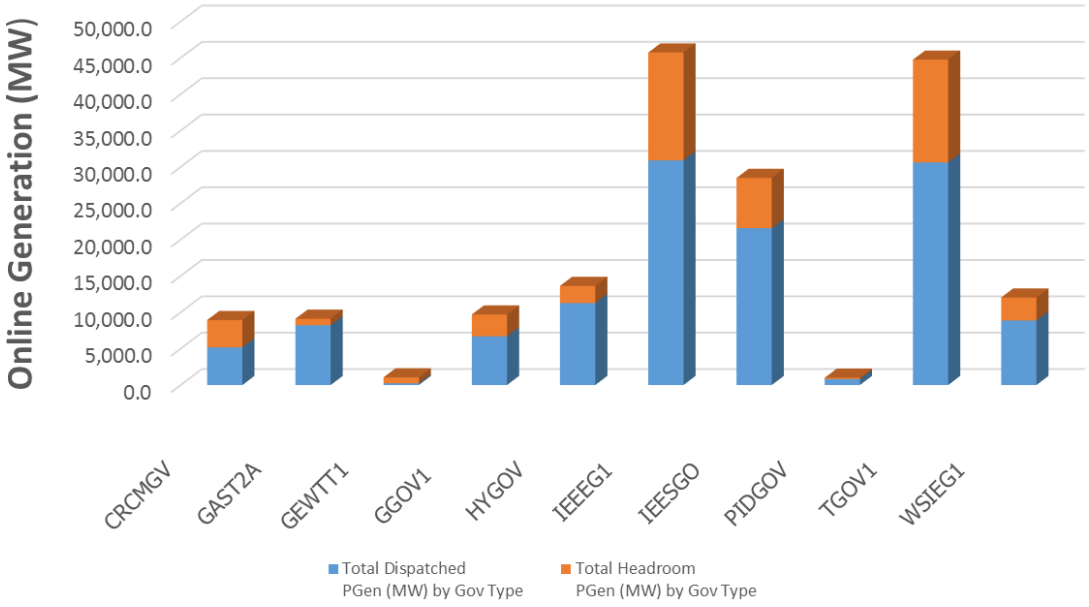


Figure A.3: Headroom by Governor Type (MW)

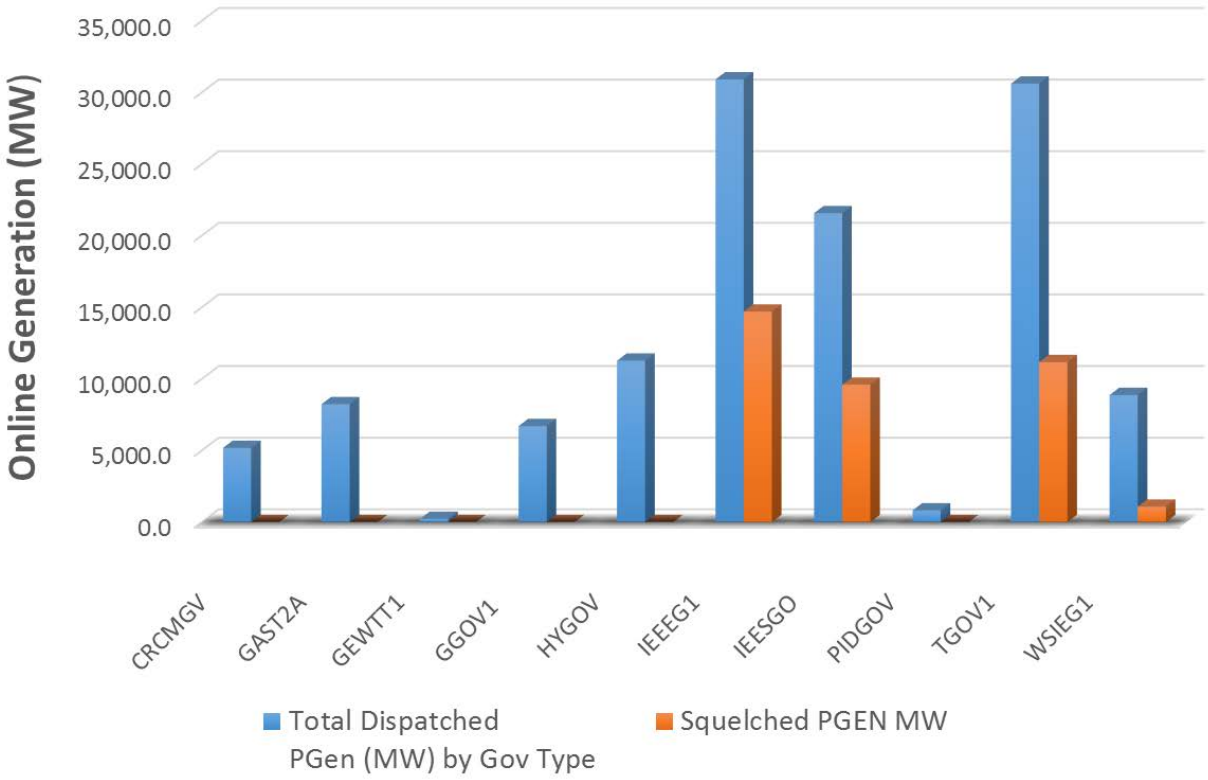


Figure A.4: Dispatched Generation vs Squelched Generation by Governor Type

The dispatched frequency responsive generation in the 2017–LL ERAG/MMWG Base Cases have 29 percent headroom capability.

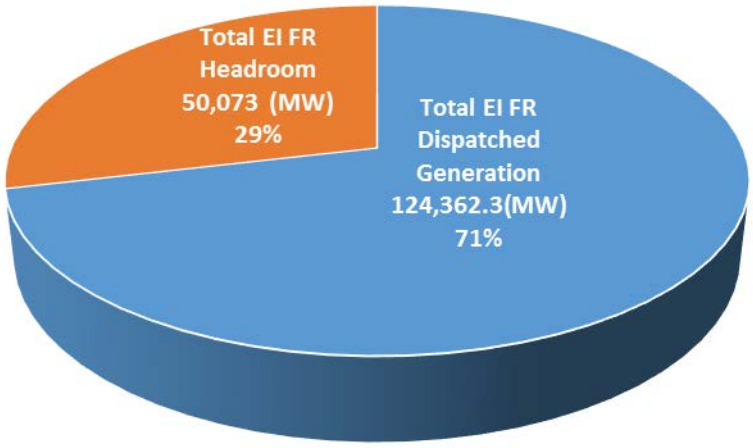


Figure A.5: Headroom verses Dispatched On-Line Frequency Responsive Generation

Appendix B: Governor Deadband Modeling

This appendix describes the deadband modeling required for governors to more accurately capture frequency response.

Deadband Modeling

Normal power system operations are characterized by continuous load variations that result in constant frequency variations on the power system. In the absence of a major disturbance, these variations are innocuous; however, the response to the small frequency variations can cause wear and tear in steam boilers and turbines. The application of a deadband controller eliminates the system response to frequency deviations that do not exceed a predefined value. With the use of a controller associated with certain deadband, the frequency response may be affected and thus the stability of the power system can be affected.[21]

One of the key frequency response modeling parameters is the governor deadband. The governor deadband setting establishes a minimum frequency deviation that must be exceeded before the governor will act. Frequency deviations that are less than the setting will not cause the governor to act. Deadband settings not to exceed +/- 0.036 Hz are recommended in the NERC Primary Frequency Control Guideline.

Presently, there is no deadband modeling for the most used PSS/E models; however, PSS/E does provide deadband governor modeling for a limited number of models. These PSS/E governors with deadband model two types of intentional deadbands.[22] Deadbands will be added to speed signal for some of the turbine-governor (TG) models in PSS®E library.

- Type 1: There is no offset in the output. Once the operation is outside the deadband, the input is passed straight through. Type 1 db1, db2, and epsilon (eps) are defined as shown in Figure B.1. PSLF's dead band model uses the parameter "eps" in a different way (i.e., to represent the hysteresis).
- Type 2: The output is offset by the deadband. Once operation is outside of the deadband, the output starts from zero and then proportionally increases with the input. For Type 2 db1, db2 are defined as shown in Figure B.2.

Type 1:

if x>db2, y= (eps/db2)*x
if x<db1, y= (eps/db1)*x
y=0 if db1<X<db2

[21] Gefei Kou, Penn Markham, Stanton Hadley, Tom King, and Yilu Liu. *Impact of Governor Deadband on Frequency Response of the U.S. Eastern Interconnection*: IEEE Transactions on Smart Grid, Vol. 7, No. 3, May 2016.

[22] Siemens Power Technologies International Proposed Deadband Modeling for PSS/E Governor Models, August 8, 2016

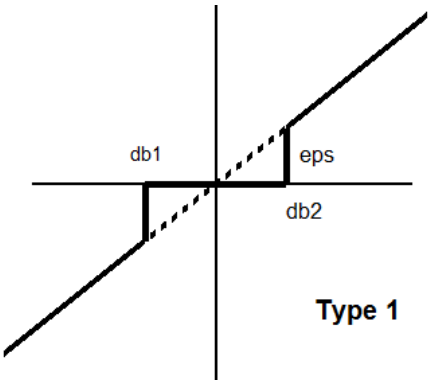


Figure B.1: Type 1 with No Offset – Input Is Passed Through

Type 2:

y = x-db2 (x>db2)

y = x-db1 (x<db1)

y = 0 (db1<x<db2)

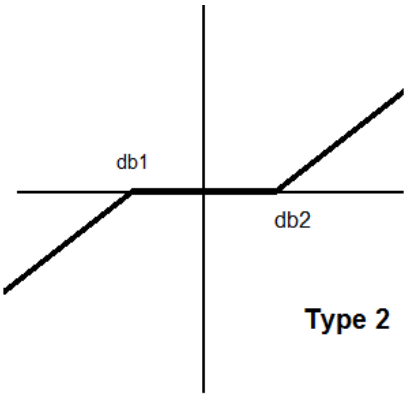


Figure B.2: Type 2 with No Offset by the Deadband

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Critical Energy/Electric Infrastructure Information Has Been Redacted

June 30, 2017

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: Remote Access Study Report, Docket No. RM15-14-___

Dear Secretary Bose:

Pursuant to Order No. 822 of the Federal Energy Regulatory Commission ("FERC" or "Commission),[1] the North American Electric Reliability Corporation hereby submits a report providing the results of a study on the remote access protections required by NERC's Critical Infrastructure Protection ("CIP") Reliability Standards ("Remote Access Study Report"). Remote access refers to the ability to access a system, application, or data from a remote location. Remote access technology allows logging into a system as an authorized user without being physically present at its keyboard. NERC completed the Remote Access Study consistent with the FERC directive in Order No. 822 to perform a study to assess: (1) the effectiveness of the controls in the CIP Reliability Standards to mitigate known remote access vulnerabilities; (2) the risks posed by remote access-related threats and vulnerabilities; and (3) appropriate mitigating controls for any identified risks.[2]

NERC is submitting a public and non-public version of the Remote Access Study Report. In the public version of this submittal, NERC redacted sensitive data regarding Critical Electric Infrastructure. NERC respectfully requests that the Commission designate the redacted portions of the Remote Access Study Report as Critical Energy/Electric Infrastructure Information ("CEII"), consistent with Section 388.113 of the Commission's regulations.[3] The redacted portions of the Remote Access Study Report provide sensitive information on the manner in which entities subject to NERC's CIP Reliability Standards have implemented security controls to protect against the risks associated with remote access to cyber assets used to control and monitor bulk-power system facilities. Among other things, the redacted portions of the Remote Access Study Report describe the type of security controls used by entities to address remote access-related threats and

[1] *Order No. 822, Revised Critical Infrastructure Protection Reliability Standards*, 154 FERC ¶ 61,037, at P 64 (2016).

[2] *Id.*

[3] 18 C.F.R. § 388.113 (2016).

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vulnerabilities and assesses the effectiveness of those controls, noting areas requiring further enhancement. As a result, the details provided in the redacted portions of Remote Access Study Report could be useful to a person planning an attack on Critical Electric infrastructure. NERC requests that the redacted portions of the Remote Access Study Report be designated as CEII for the full period allowed under the Commission's regulations.[4]

Should you have any questions, please do not hesitate to contact the undersigned.

Respectfully submitted,

/s/ Shamai Elstein
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[4] 18 C.F.R. § 388.113(e)(1).

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Remote Access Study Report

June 30, 2017

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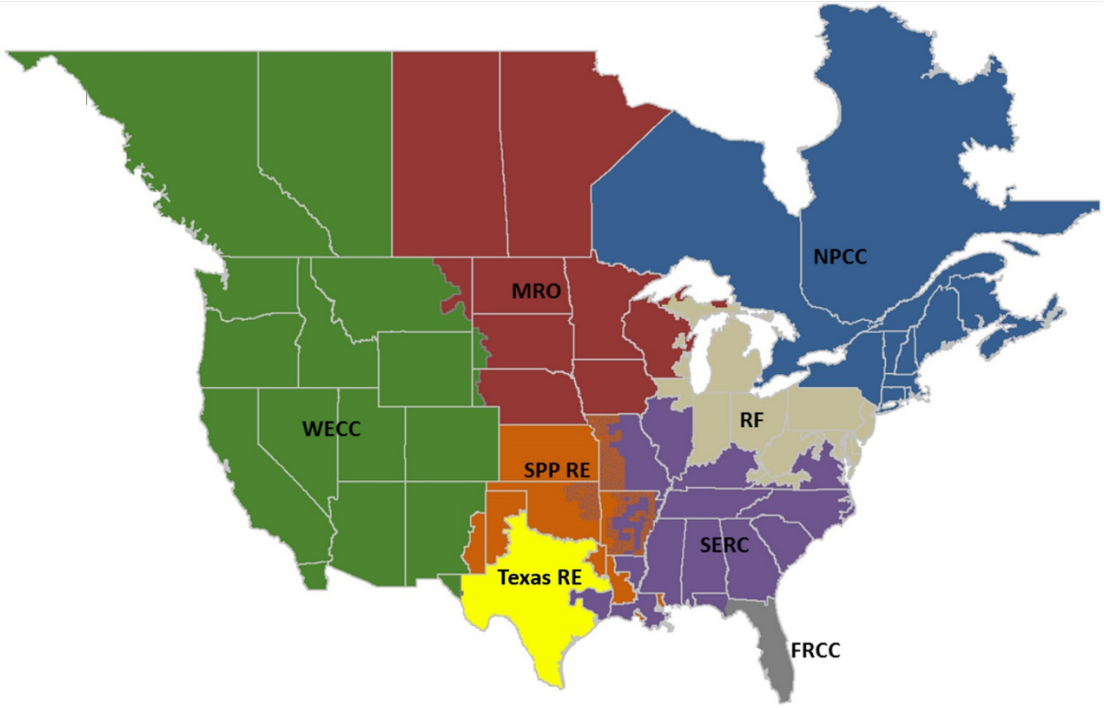
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

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



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

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

This report provides the results of NERC's study on the remote access protections in NERC's Critical Infrastructure Protection (CIP) Reliability Standards (Remote Access Study or Study).[1] Remote access refers to the ability to access a system, application, or data from a remote location. Remote access technology allows logging into a system as an authorized user without being physically present at its keyboard. NERC completed the Remote Access Study consistent with the FERC's directive in Order No. 822 to perform a study to assess: (1) the effectiveness of the controls in the CIP Reliability Standards to mitigate known remote access vulnerabilities; (2) the risks posed by remote access-related threats and vulnerabilities; and (3) appropriate mitigating controls for any identified risks.[2]

In conducting the Remote Access Study, NERC found that the existing protections required by the CIP Reliability Standards and the manner in which registered entities have implemented those protections are largely effective in mitigating many of the risks associated with remote access. NERC observed that registered entities have implemented effective security controls in compliance with the remote access protections in the CIP Reliability Standards, with few exceptions identified during compliance monitoring activities, and, in many cases, implemented additional remote access controls beyond those required by the CIP Reliability Standards to further strengthen their security posture. NERC also identified certain areas that may require additional focus to ensure that risks related to remote access are effectively mitigated.

This report summarizes NERC's findings from the Remote Access Study. As discussed below, NERC identified 19 areas for continued focus. These areas are categorized in the following manner in this report:

- **Effective Mitigating Practices** – This category refers to security and operational practices implemented by registered entities that were particularly effective at mitigating risks and represent opportunities for outreach and information sharing to further their use throughout the industry.
- **Areas for Further Analysis** – This category refers to areas for additional research, potential standards modifications, or technical guidance to more accurately address remote access-related threats and vulnerabilities.
- **Enhancement Opportunities** – This category refers to areas where NERC and the Regional Entities, (collectively, the ERO Enterprise) can help facilitate the use of industry best practices within the confines of the CIP Reliability Standards.
- **Training and Awareness** – This category refers to those security controls, best practices, and other methods to demonstrate compliance that may not be well understood by registered entities and may require training, outreach, or guidance to improve industry awareness on controls that can be used to mitigate the risks associated with remote access.

This report is organized as follows:

- *Section 1* discusses the risks posed to the Bulk Electric System (BES) by remote access-related threats and vulnerabilities.

[1] Unless otherwise designated, all capitalized terms used herein shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* (NERC Glossary), http://www.nerc.com/files/Glossary_of_Terms.pdf. For ease of reference, Appendix B hereto includes a glossary of terms used in this report.

[2] Order No. 822, *Revised Critical Infrastructure Protection Reliability Standards*, 154 FERC ¶ 61,037, at P 64 (2016) (approving Reliability Standards CIP-003-6, CIP-004-6, CIP-006-6, CIP-007-6, CIP-009-6, CIP-010-2 and CIP-011-2).

- *Section 2* explains the manner in which the currently-effective CIP Reliability Standards address those risks.
- *Section 3* provides the ERO Enterprise's observations on the manner in which registered entities have implemented controls to address the risks associated with remote access.
- *Section 4* examines the effectiveness of the CIP Reliability Standards and registered entities implementation of those standards in mitigating the risks posed by remote access, and describes areas that may require additional consideration to ensure that remote access risks are effectively mitigated.
- *Section 5* discusses next steps to address the areas identified for further consideration.

Section 1. Remote Access Related Threats and Vulnerabilities

Remote access refers to the ability to access a system, application, or data from a remote location. Remote access can take one of two forms: (1) human or user-initiated remote access, referred to as Interactive Remote Access in NERC's CIP Reliability Standards; or (2) automated system-to-system access. Registered entities frequently use Interactive Remote Access technologies to enable remote users to operate, support, and maintain control systems networks and other BES Cyber Systems. Among other things, providing for remote access enables users to efficiently access Cyber Assets to troubleshoot application software issues and repair data and modeling problems that cause application errors.

In addition, registered entities frequently use system-to-system (or machine-to-machine) remote access for, among other things, data exchange. For instance, Inter-Control Center Communications Protocol (ICCP) is the most common form of data-sharing communications between control centers and often relies on system-to-system remote access. Using a network connection, ICCP enables one energy management system (EMS) to exchange real-time operational data with another EMS at a remote electric power entity.

These remote access technologies, while important for efficiently operating, supporting, and maintaining Cyber Assets, including those for control systems, could open up attack vectors. If not properly secured, remote access could result in unauthorized access to a registered entity's network and control systems, with potentially serious consequences. An attacker, for instance, could breach an environment via remote access by deliberately compromising security controls to obtain privileged access to critical systems. Although registered entities generally do not rely on Internet facing systems to operate and monitor the BES, malicious actors have demonstrated capabilities to infiltrate systems that are not Internet facing, such as systems designed to run autonomously with minimal human interaction and other mission critical applications that are used to perform supervisory control that, if misused, could result in serious reliability issues. Additionally, a compromised device that is allowed to remotely access a Cyber Asset can serve as a gateway for cyber-criminals to attack networks.

Once the attacker gains remote access to the system, the attacker could then upload malware, copy sensitive data, compromise other computer systems, and even operate BES elements to undermine the reliability of the BES. As evidenced by the cyber-attacks on Ukrainian power companies in December 2015 that resulted in power outages impacting a large number of customers, unauthorized access could be used to operate transmission and generation assets in a malicious manner by a remote user.[3] Additionally, as evidenced by the December 2016 cyber-attack in Kiev, Ukraine which adversely affected electric grid operations, malware can be preconfigured to scan and evaluate networks to target susceptible systems and force them to misoperate or operate in a manner counter to their intended use.[4] Malware does not require a malicious actor or direct human intervention in order for it to compromise target systems, and in turn present real threats to the autonomous systems used in substations and generators where user intervention is not expected. Malicious actors and malware programs can also target BES Cyber Systems with denial of service attacks, which could render operational networks and systems inoperable or result in outages.

Cyber security threats continue to evolve. The electric industry's reliance on systems and technologies that are commonly available could enable adversaries to develop tools and mechanisms to compromise the most ubiquitous systems. Registered entities must therefore continue to implement and reinforce sound security

[3] *See* DHS, ICS-Cert, Cyber-Attack Against Ukrainian Critical Infrastrucutre (Feb. 25, 2016), https://ics-cert.us-cert.gov/alerts/IR-ALERT-H-16-056-01.

[4] *See* CRASHOVERRIDE, Analysis of the Threat to Electric Grid Operations, https://dragos.com/blog/crashoverride/CrashOverride-01.pdf.

measures within their organizations to mitigate the risks associated with remote access. Training, security policies, and documented processes help ensure that security is not compromised through the introduction of unsecured computers or unsecured access. Properly configuring software on devices used to remotely access BES Cyber Systems, and implementing securely designed network architectures are crucial for continued security of the BES Cyber Systems. Also essential are secure methods to authenticate users. As discussed in the following section, the CIP Reliability Standards require applicable registered entities to implement a number of fundamental security controls when permitting remote access to networks containing BES Cyber Systems.

Section 2. CIP Reliability Standards Addressing Remote Access

The currently-effective CIP Reliability Standards require registered entities to implement a number of security controls for remote access. Specifically, the CIP Reliability Standards include the following requirements for remote access protection:

- *CIP-003-6, Requirement R1*: Entities must have cyber security policies governing remote access to BES Cyber Systems. Senior management must approve these policies to help ensure that secure practices are implemented.
- *CIP-004-6, Requirement R1*: Responsible entities must implement a cybersecurity awareness program that, at least once a calendar quarter, reinforces cyber security practices, which may include practices related to remote access.
- *CIP-004-6, Requirement R2*: All personnel who have remote access capability must periodically receive training that reinforces cyber security practices.
- *CIP-004-6, Requirement R4, Part 4.1-4.3*: All personnel who have remote access must be explicitly authorized and periodically reviewed to ensure such access is limited and controlled.
- *CIP-004-6, Requirement R5, Parts 5.1 and 5.1*: To ensure that terminated or transferred personnel do not retain the ability to access BES Cyber Systems remotely, entities must revoke the access rights of terminated or transferred personnel.
- *CIP-005-5, Requirement R1, Part 1.1*: Entities must protect all BES Cyber Systems with routable connectivity by including them in an Electronic Security Perimeter (ESP) to control access. An ESP is defined as the logical border surrounding a network to which BES Cyber Systems are connected using routable protocol.
- *CIP-005-5, Requirement R1, Part 1.2*: All connections to BES Cyber Systems originating from outside the ESP must be through an identified access point (through a firewall) so that all connections are known and controlled.
- *CIP-005-5, Requirement R1, Part 1.3*: For all connections to BES Cyber Systems inside the ESP there must be a documented reason for such access, both inbound and outbound, and a denial to all other access.
- *CIP-005-5, Requirement R1, Part 1.4*: Remote access via dial-up connectivity must be authenticated.
- *CIP-005-5, Requirement R1, Part 1.5*: All inbound and outbound communications must be examined to detect malicious communication.
- *CIP-005-5, Requirement R2, Part 2.1*: Interactive Remote Access to BES Cyber Systems must go through an Intermediate System (limiting the entry points to the ESP and controlling the types of access allowed to BES Cyber Systems).
- *CIP-005-5, Requirement R2, Part 2.2*: Interactive Remote Access sessions must be encrypted to the Intermediate System to protect the confidentiality and integrity of the communications.
- *CIP-005-5, Requirement R2, Part 2.3*: Interactive Remote Access sessions must have multi-factor authentication to ensure only appropriate personnel have access.
- *CIP-007-6, Requirement R1, Part 1.1*: BES Cyber Systems are further protected from potential remote access attacks by limiting their network exposed ports and services to only those required for operation of the system.
- *CIP-007-6, Requirement R4*: In the event of unauthorized or suspicious remote access, entities must keep event logs and periodically review them for intervention or after-the-fact analysis.

- *CIP-007-6, Requirement R5, Part 5.1*: Remote access users of BES Cyber Systems must also authenticate their interactive use access session to the BES Cyber System.

The primary focus of the remote access protections in the CIP Reliability Standards is to address user-initiated remote access, referred to as Interactive Remote Access. Interactive Remote Access is defined in the NERC Glossary as:

> *User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.*

CIP Reliability Standard CIP-005-5, Requirements R1 and R2 provide the core controls for mitigating the risks associated with network connectivity and Interactive Remote Access. The following is a more in-depth discussion of those requirements and the manner in which they address remote access-related threats and vulnerabilities.

Pursuant to CIP-005-5, Requirement R1, registered entities must establish the following network connectivity protections:

- All applicable Cyber Assets connected to a network via a routable protocol shall reside within a defined ESP.
- All External Routable Connectivity[5] must be through an identified Electronic Access Point (EAP).
- Require inbound and outbound access permissions, including the reason for granting access, and deny all other access by default.
- Where technically feasible, perform authentication when establishing Dial-up Connectivity with applicable Cyber Assets.
- Have one or more methods for detecting known or suspected malicious communications for both inbound and outbound communications.

The ESP-related requirements in CIP-005-5, Requirement R1 essentially create a "trust-zone" to segment BES Cyber Systems from non-trusted environments. The ESP serves to control traffic at the external electronic boundary of the BES Cyber System and provides a first layer of defense for network based attacks as it limits reconnaissance of targets, restricts and prohibits traffic to a specified rule set, and assists in containing any successful attacks.

[5] External Routable Connectivity is defined in the NERC Glossary as "[t]he ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection."

Under CIP-005-5, Requirement R2, registered entities allowing Interactive Remote Access into an ESP must implement the following security controls to mitigate the risk from unauthorized users accessing high and medium impact BES Cyber Systems and their associated Protected Cyber Assets:

- Use an Intermediate System such that the Cyber Asset initiating Interactive Remote Access does not directly access an applicable Cyber Asset.
- For all Interactive Remote Access sessions, use encryption that terminates at an Intermediate System.
- Require multi-factor authentication for all Interactive Remote Access sessions.

The term Intermediate System is defined in the NERC Glossary as:

> *A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.*

The use of an Intermediate System prohibits remote users from directly accessing Cyber Assets inside an ESP and potentially exposing these Cyber Assets to vulnerabilities that may exist on the remote user's device. A jump host, which is part of the Intermediate System, acts as a proxy to facilitate communications from the remote user to Cyber Assets within the ESP. Forcing all Interactive Remote Access through the jump host allows the registered entities to limit the permitted ESP firewall access control list rules to only those required to facilitate communications with the jump host. Additionally, external facing firewalls can also limit access control list rules to only those rules required to facilitate communications between the remote user and the jump host.

The use of encryption provides additional protections. Encryption is used to protect the confidentiality and integrity of data that is sent between the remote computer and the Intermediate System. Data encryption is important for anyone who wants or needs secure data transfer. Encryption is needed when there is a risk of unauthorized interception of transmissions on the communications link. It is especially important when using the Internet as the communication means.

The use of multi-factor authentication provides an added layer of security. Passwords can be guessed, stolen, hijacked, found, or given away. They are subject to automated attacks including brute force attacks, in which possible passwords are tried until the password is found, or dictionary attacks, where words and word combinations are tested as possible passwords. But if a password or PIN must be supplied along with a one-time password supplied by a token, a fingerprint, or some other factor, the password is of no value unless the other factors required for authentication are also acquired.

In conducting the Remote Access Study, NERC focused on the specific network connectivity and Interactive Remote Access protections in CIP-005-5, Requirements R1 and R2 as these requirements are the focal point of the remote access protections in the CIP Reliability Standards. As explained in the following section, NERC staff reviewed the manner in which entities implemented Reliability Standards CIP-005-5 and found that the required protections are helping to effectively mitigate many of the risks associated with Interactive Remote Access.

Section 3. Assessment of Remote Access Control Implementation

To help assess the effectiveness of the remote access controls required by the CIP Reliability Standards and determine if the appropriate mitigating controls are in place, NERC, working with the Regional Entities, reviewed the manner in which registered entities implementated remote access controls, including those required by the CIP Reliability Standards as well as any additional security controls. The ERO Enterprise used information gathered from over 30 completed audits of registered entities between July 1, 2016 and May 15, 2017. The 30 audits covered registered entities representing the following functional registrations: Balancing Authority (BA); Distribution Provider (DP); Generator Owner (GO); Generator Operator (GOP); Planning Coordinator (PC); Reliability Coordinator (RC); Resource Planner (RP); Transmission Owner (TO); Transmission Operator (TOP); Transmission Planner (TP); and Transmission Service Provider (TSP).

NERC examined the Regional Entities' assessment of each audited registered entity, along with supporting information such as work papers and related compliance evidence. The ERO Enterprise also developed a questionnaire for use during audits and spot checks, referred to as the "Remote Access Form", which can be found in Appendix A, to gather specific data on the implementation of remote access controls. Among other things, NERC reviewed registered entities' network and firewall device configurations, Interactive Remote Access procedures, network management procedures, Electronic Access Control or Monitoring Systems (EACMS) configuration files, and participant interview notes. NERC also reviewed audit reports and self-reports to identify areas of noncompliance related to remote access protections for trends and areas of focus to improve remote access control implementation.

Using this information, NERC assessed the relative strengths and weaknesses of registered entities' remote access and network access controls. As discussed in greater detail below, NERC found that the registered entities' remote access architectures are generally compliant with the CIP-005-5 requirements and the security controls are generally effective at mitigating vulnerabilities.

Observations of Remote Access Control Implementation

The following section provides NERC's observations of registered entities implementation of remote access controls based on the data gathered on each of the items included in the Remote Access Form.

Item 1 – Network Architecture

Item 1 of the Remote Access Form requested the following information to be evaluated by the Regional Auditor:

> *Review a sample of the registered entity's Electronic Security Perimeters (ESPs). Evaluate applicable access controls, intrusion detection capabilities, malware prevention capabilities, etc. Document for the study any notable strengths or weaknesses in these areas.*

The focal point of this item was to evaluate the architectural components associated with the registered entity's ESP infrastructure used to support remote access. In accordance with CIP-005-5, Requirement R1, Part 1.1, registered entities segmented their operational technology routable networks that contained their BES Cyber Systems from other networks, such as their corporate networks. Most of the registered entities from which NERC

collected data implemented multiple ESPs for their primary Control Centers, backup Control Centers, and substations, as applicable.[6]

[redacted]

Item 2 – Interactive Remote Access

Item 2 of the Remote Access Form requested the following information to be evaluated by the Regional Auditor:

> *Review and evaluate the entity's architecture for Interactive Remote Access. Document for the study any notable strengths or weaknesses in the entity's approach, including session encryption, identification and protection of Intermediate Systems, use and appropriateness of authentication services (Active Directory, Lightweight Directory Access Protocol (LDAP), RSA, etc.), strength of multi-factor user authentication, etc.*

The focal point of this item was to understand and evaluate the controls associated with the registered entity's remote access architecture.

Interactive Remote Access and Intermediate Systems Architecture

[redacted]

[6] None of the entities observed during the Remote Access Study had generation facilities with high or medium impact BES Cyber Systems subject to Reliability Standard CIP-005-5.

[redacted]

Intermediate Systems

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Remote User Systems

[redacted]

7 [redacted]

[redacted]

[redacted]

[redacted]

Item 3 – Additional Interactive Remote Access Protections

Item 3 of the Remote Access Form requested the following information to be evaluated by the Regional Auditor:

> *Review and evaluate the registered entity's architecture for Interactive Remote Access. Document for the study any notable strengths or weaknesses in the entity's approach, including session encryption, identification and protection of Intermediate Systems, use and appropriateness of authentication services (Active Directory, Lightweight Directory Access Protocol (LDAP), RSA, etc.), strength of multi-factor user authentication, etc. Evaluate the controls applicable to Interactive Remote Access. Document for the study any notable strengths or weaknesses in the entity's controls:*
>
> *a. Assess the monitoring of actions that may be taken by the remote user who has successfully authenticated to the Intermediate System, if any:*
>
> *i. Session logging,*
>
> *ii. Key stroke logging,*
>
> *iii. Screen captures,*
>
> *iv. Automated session terminations, and*
>
> *v. Audit logging of all actions taken.*
>
> *b. Assess controls for the required encryption that terminates at the Intermediate System:*
>
> *i. Encryption strength, and*
>
> *ii. Encryption key updates.*
>
> *c. Evaluate the mitigation of risks posed by corporate networks to Intermediate Systems:*
>
> *i. E.g., DMZs used to protect jump hosts and authentication services.*

Remote User Session Monitoring

[redacted]

[redacted]

Encryption

[redacted]

Demilitarized Zone (DMZ)

[redacted]

8 [redacted]

[redacted]

[redacted]

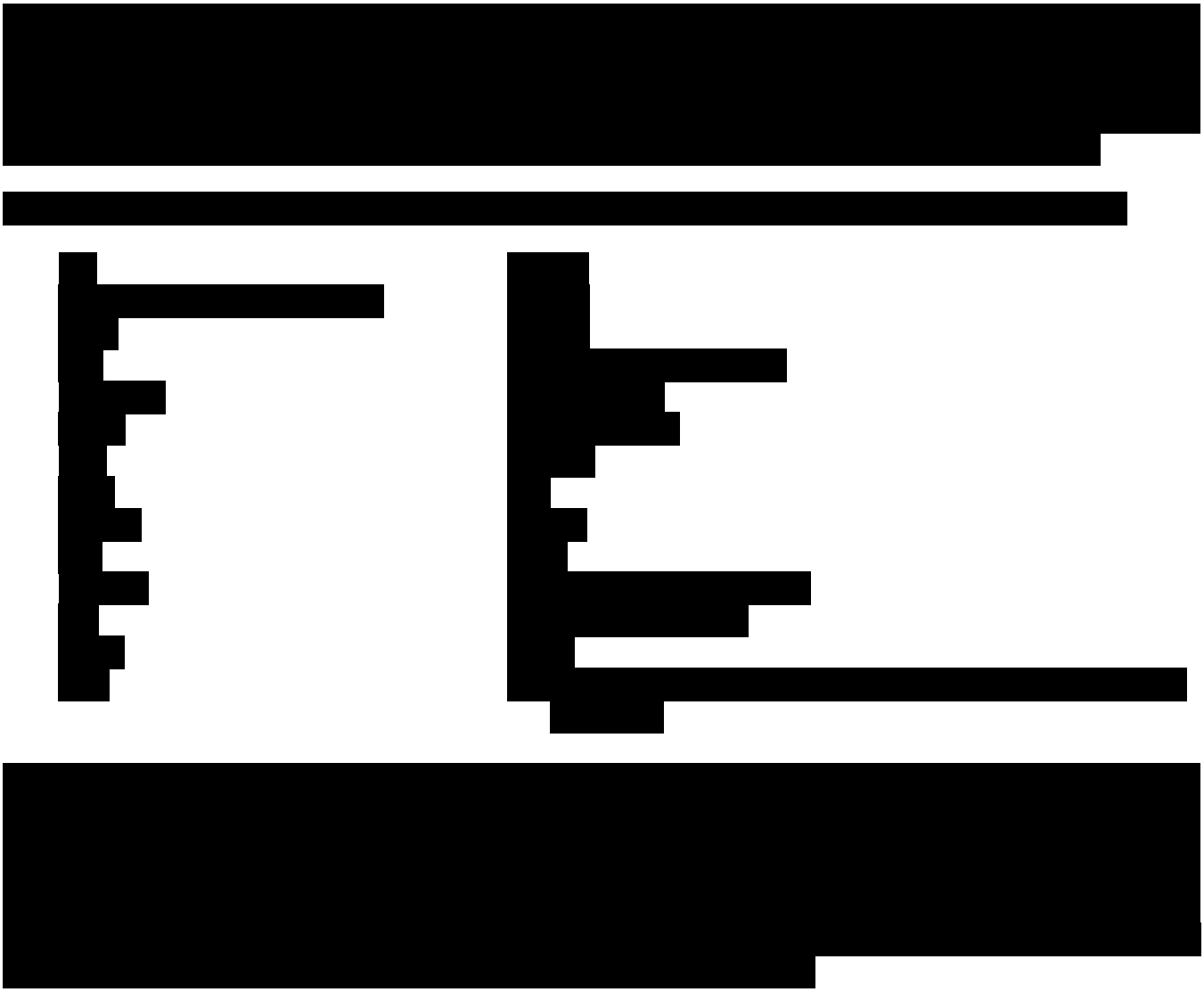
Item 4 – System-to-System Remote Access

Item 4 of the Remote Access Form requested the following information to be evaluated by the Regional Auditor:

> *Evaluate the protections provided for system-to-system communications crossing the ESP boundary. Document for the study the protocols used and any notable strengths or weaknesses in these protections. Systems-to-system communications may include:*
>
> *a. ICCP (Inter-Control Center Communications Protocol),*
>
> *b. Management console communications,*
>
> *c. DNP/IP (Distributed Network Protocol over Internet Protocol),*
>
> *d. Modbus/IP (Modbus over Internet Protocol),*
>
> *e. SQL*Net (Oracle client/server middleware),*
>
> *f. Replication,*
>
> *g. Failover, and/or Other protocols*

The focal point of this item was to evaluate the controls associated with system-to-system remote access. [redacted]

[redacted]



Item 5 – Lessons Learned from Cyber Incident in the Ukraine

Item 5 of the Remote Access Form requested the following information to be evaluated by the Regional Auditor:

Evaluate and document for the study the entity's controls to address the Ukraine's specific Remote Access Vulnerabilities:

- *Spear phishing and malware detection capabilities on Corporate Networks*
- *Application whitelisting*[9]
- *Disabling of macros at email servers and in Windows-based applications*
- *Application of Lessons Learned on Mixed-Trust EACMS to ensure that credentials from corporate enterprise cannot be exploited by escalation tactics*

[9] Application whitelisting is a cyber security control that requires applications to be predefined and permitted to execute on a Cyber Asset. Any application that does not have an explicit permission to execute will be prevented from executing. This differs from traditional cyber security controls where applications are permitted to execute unless an anti-malware software identifies an application as malware and prevents it from executing. If a malware manages to get onto a Cyber Asset with whitelisting protection, the malware could not execute since it does not have permission to do so.

- *Protection for IP to serial converters*
- *Other protections implemented*

The focal point of this item was to understand and evaluate the steps registered entities took to address vulnerabilities that led to the cyber incident in the Ukraine. A cyber-attack was perpetrated against electric utilities in the Ukraine in December 2015, resulting in power outages that affected at least 225,000 customers. The attackers initially compromised the business networks of the utilities and used credentials obtained on those networks to gain access to the industrial control system networks including the networks that housed SCADA systems. The attackers used credentials to access SCADA systems at multiple control centers and opened breakers at substations. The attackers also used their access to change the firmware on substation communications infrastructure, rendering the devices useless. More details of the cyber-attack may be found in the ICS-CERT report Cyber-Attack Against Ukrainian Critical Infrastructure.

To better understand the manner in which registered entities are addressing remote access risk, NERC requested information from registered entities on actions taken to prevent potential cyber hackers from gaining access to corporate networks and escalating privileges to gain access to Cyber Assets inside the ESP. The following are NERC's findings on this matter:

[redacted]

[redacted]

[redacted]

[redacted]

10 [redacted]

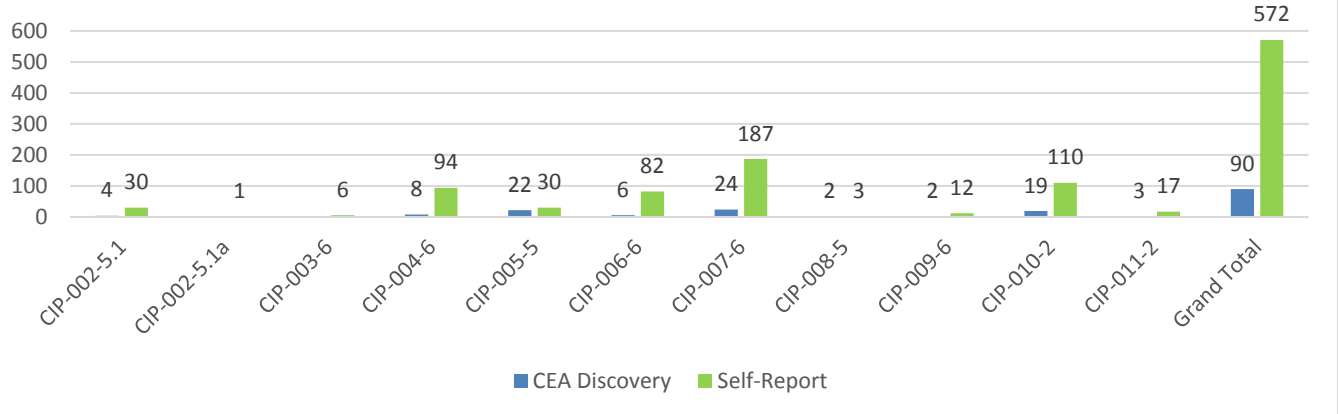
[redacted]

[redacted]

Compliance Monitoring Observations

As noted above, NERC also reviewed audit reports to identify areas of noncompliance related to remote access protections to identify trends and areas of focus to improve implementation of remote access controls. Table 1 below summarizes the number of instances of noncompliance of the CIP Reliability Standards the ERO Enterprise identified from July 1, 2016 through May 15, 2017. As shown in Table 1, there were 662 instances of noncompliance. Of the total number of noncompliance, however, only 52 or eight percent (22 instances of discovered by the ERO Enterprise and 30 instances of self-reports) of those instances were related to remote access or otherwise associated with CIP-005-5, which includes the primary requirements application to remote access.

Table 1
Total New CIP V5 Standards by Self-Report/CEA Discovery
Discovered- July 1, 2016 - May 15, 2017



[redacted]

Section 4. Effectiveness of Remote Access Protections

In conducting the Remote Access Study, NERC staff found that the existing protections required by the CIP Reliability Standards and the manner in which registered entities have implemented those protections are effective in mitigating many of the risks associated with remote access. The requirements outlined in Section 2 above – from the training requirements, to the electronic access requirements, and the core requirements in CIP-005-5 applicable to Interactive Remote Access – address many of the risks associated with remote access, establishing barriers to unauthorized access to BES Cyber Systems, and their associated Protected Cyber Assets. Similarly, as described in Section 3, NERC observed that, with a few exceptions, registered entities have implemented effective security controls in compliance with the remote access protections in the CIP Reliability Standards and, in many cases, implemented remote access controls beyond those required by the CIP Reliability Standards to further strengthen their security posture. NERC also identified certain areas that may require additional consideration to ensure that risks related to remote access are effectively mitigated.

This section summarizes NERC's findings from the Remote Access Study. As noted above, NERC identified 19 areas for continued focus. These areas are categorized in the following manner:

- **Effective Mitigating Practices** – This category refers to security and operational practices implemented by registered entities that were particularly effective at mitigating risks and represent opportunities for outreach and information sharing to further their use throughout the industry.

- **Areas for Further Analysis** – This category refers to areas for additional research, potential standards modifications, or technical guidance to more accurately address remote access-related threats and vulnerabilities.

- **Enhancement Opportunities** – This category refers to areas where the ERO Enterprise can help facilitate the use of industry best practices within the confines of the CIP Reliability Standards.

- **Training and Awareness** – This category refers to those security controls, best practices, and other methods to demonstrate compliance that may not be well understood by registered entities and may require training, outreach, or guidance to improve industry awareness on controls that can be used to mitigate the risks associated with remote access.

Effective Mitigating Practices

[redacted]

[redacted]

11 [redacted]

12 [redacted]

Areas for Further Analysis

[redacted]

Enhancement Opportunities

[13]

[redacted]

Training and Awareness

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

14 [redacted]

15 [redacted]

Section 5. Next Steps

As discussed in Section 4, NERC identified a number of areas for consideration to further enhance the security posture of the electric industry. NERC will use its various reliability tools, including training and outreach, the issuance of security guidelines, or modifications to the CIP Reliability Standards, as appropriate, to address the issues identified in this report and enhance remote access protections. Appendix C hereto provides NERC's action plan for addressing the issues identified in this report.

The ERO Enterprise will also continue to emphasize the evaluation of remote access controls during compliance monitoring engagements. As described in Section 3, there are opportunities to improve the consistent and effective implementation of the remote access protections required by the CIP Reliability Standards. NERC will continue reviewing audit reports and self-reports to identify trends indicating areas for future focus. NERC will continue to help ensure that registered entities apply the appropriate Interactive Remote Access controls as defined by the CIP Standards, providing periodic updates to industry on remote access compliance performance issues and opportunities, and additional focus on effective controls and the use of best practices for securing remote access connections.

The threat landscape is constantly changing and requires adaptation and information sharing on how best to address these issues in an effective and efficient manner. The results from this effort show very positive steps have been taken to address remote access protections. The ERO Enterprise will continue monitoring the implementation of remote access controls and work with industry and FERC to address the areas identified in this report as a further step toward our shared commitment of assuring the reliability and security of the North American bulk power system.

Appendix A: Remote Access Form

The ERO Enterprise gathered specific information about registered entities implementation of remote access controls through the use of the Remote Access Form. The form directed Regional Entity auditors to obtain the following information:

- **Item 1** – Review a sample of the registered entity's ESPs. Evaluate applicable access controls, intrusion detection capabilities, malware prevention capabilities, etc. Document any notable strengths or weaknesses in these areas.
  - *Applicable CIP Reliability Standards: CIP-005-5, Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, and 1.5*
- **Item 2** – Review and evaluate the registered entity's architecture for Interactive Remote Access. Document any notable strengths or weaknesses in the entity's approach, including session encryption, identification and protection of Intermediate Systems, use and appropriateness of authentication services (Active Directory, Lightweight Directory Access Protocol (LDAP), RSA, etc.), strength of multi-factor user authentication, etc.
  - *Applicable CIP Reliability Standards: CIP-005-5, Requirement R2, Parts 2.1, 2.2, 2.3*
- **Item 3** – Evaluate the controls applicable to Interactive Remote Access. Document any notable strengths or weaknesses in the registered entity's controls:
  - Assess the monitoring of actions that may be taken by the remote user who has successfully authenticated to the Intermediate System, if any:
    - Session logging,
    - Key stroke logging,
    - Screen captures,
    - Automated session terminations, and/or
    - Audit logging of all actions taken.
  - Assess controls for the required encryption that terminates at the Intermediate System:
    - Encryption strength, and
    - Encryption key updates.
  - Evaluate the mitigation of risks posed by corporate networks to Intermediate Systems:
    - E.g., DMZs used to protect jump hosts and authentication services.
    - Evaluate the mitigation of risks posed by multi-use systems (corporate AD servers, RSA services also use for Internet-based access to corporate networks, etc.) when used by Intermediate Systems.
      - *Applicable CIP Reliability Standards: CIP-005-5, Requirement R1, Part 1.5*
- **Item 4** – Evaluate the protections provided for system-to-system communications crossing the ESP boundary. Document for the study the protocols used and any notable strengths or weaknesses in these protections. Systems-to-system communications may include:
  - ICCP
  - Management console communications
  - DNP/IP (Distributed Network Protocol over Internet Protocol)
  - Modbus/IP

- SQL*Net (Oracle client/server middleware)
- Replication
- Failover, and/or
- Other protocols
- *Applicable CIP Reliability Standards: CIP-005-5, Requirement R1, Part 1.3*

- **Item 5** – Evaluate and document the registered entity's controls to address specific remote access vulnerabilities related to the cyber-attack against Ukrainian critical infrastructure:
  - Spear phishing and malware detection capabilities on Corporate Networks
  - Application whitelisting
  - Disabling of macros at email servers and in Windows-based applications
  - Application of Lessons Learned on mixed-trust EACMS to ensure that credentials from corporate enterprise cannot be exploited by escalation tactics
  - Protection for IP to serial converters, if any, and/or
  - Other protections implemented

Appendix B: Definitions

Glossary Term	Glossary Definition
BES Cyber Asset	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.
BES Cyber System	One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.
Control Center	One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in realtime to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.
Cyber Assets	Programmable electronic devices, including the hardware, software, and data in those devices.
Dial-up Connectivity	A data communication link that is established when the communication equipment dials a phone number and negotiates a connection with the equipment on the other end of the link.
Electronic Access Control or Monitoring Systems	Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems.
Electronic Access Point	A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.
Electronic Security Perimeter	The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.
External Routable Connectivity	The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection.
Interactive Remote Access	User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1. Cyber Assets used or owned by the Responsible Entity 2. Cyber Assets used or owned by employees, and 3. Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.

Glossary Term	Glossary Definition
Intermediate System	A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.
Protected Cyber Assets	One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP.

Appendix C: NERC Outreach and Coordination Activities

No.	Topic	Target Date	NERC Outreach & Coordination Activities
1	[redacted]	Q4 2018	NERC Webinar, Critical Infrastucture Protection Committee (CIPC) coordination,[16] ERO Training
2	[redacted]	Q4 2018	NERC Webinar, CIPC coordination, ERO Training
3	[redacted]	Q2 2018	NERC Webinar, CIPC coordination
4	[redacted]	Q4 2017	NERC Webinar, CIPC coordination
5	[redacted]	Q4 2018	NERC Webinar, CIPC coordination
6	[redacted]	Q4 2017	NERC Webinar, CIPC coordination, ISAC Advisory
7	[redacted]	Q4 2017	CMEP Area of Focus, NERC Webinar, CIPC coordination
8	[redacted]	Q2 2018	NERC Webinar, Present issue to CIP standard drafting team (SDT), CIPC coordination
9	[redacted]	Q4 2018	NERC Webinar, CIPC coordination, ERO Training, ISAC Advisory
10	[redacted]	Q4 2017	NERC Webinar, Present issue to CIP SDT, CIPC coordination
11	[redacted]	Q4 2017	NERC Webinar Present issue to CIP SDT, CIPC coordination
12	[redacted]	Q2 2018	NERC Webinar, Present issue to CIP SDT, CIPC coordination
13	[redacted]	Q2 2018	NERC Webinar, CIPC coordination, ISAC Advisory
14	[redacted]	Q4 2018	NERC Webinar, Present issue to CIP SDT, CIPC coordination
15	[redacted]	Q2 2018	NERC Webinar, CIPC coordination
16	[redacted]	Q4 2017	NERC Webinar, Present issue to CIP SDT, CIPC coordination

[16] The CIPC consists of cyber and physical security subject matters experts and helps NERC advance the physical security and cybersecurity of the critical electricity infrastructure of North America by, among other things, working closely with NERC operating and planning committees to identify needs for new or revised CIP standards and developing security guidelines to enhance industry protctions. NERC will consult with CIPC subject matter experts to help address the issues identified in the Remote Access Study.

No.	Topic	Target Date	NERC Outreach & Coordination Activities
17	[redacted]	Q4 2018	NERC Webinar, CIPC coordination
18	[redacted]	Q2 2018	NERC Webinar, Present issue to CIP SDT, CIPC coordination
19	[redacted]	Q2 2018	NERC Webinar, CMEP Area of Focus

Appendix D: CIP Reliability Standards That Impact EACMS

CIP Reliability Standards Requirements and Parts	
CIP-003-6, Requirement R1	CIP-007-6, Requirement R4, Part 4.1
CIP-004-6, Requirement R2, Part 2.1	CIP-007-6, Requirement R4, Part 4.2
CIP-004-6, Requirement R2, Part 2.2	CIP-007-6, Requirement R4, Part 4.3
CIP-004-6, Requirement R2, Part 2.3	CIP-007-6, Requirement R4, Part 4.4
CIP-004-6, Requirement R3, Part 3.1	CIP-007-6, Requirement R5, Part 5.1
CIP-004-6, Requirement R3, Part 3.2	CIP-007-6, Requirement R5, Part 5.2
CIP-004-6, Requirement R3, Part 3.3	CIP-007-6, Requirement R5, Part 5.3
CIP-004-6, Requirement R3, Part 3.4	CIP-007-6, Requirement R5, Part 5.4
CIP-004-6, Requirement R3, Part 3.5	CIP-007-6, Requirement R5, Part 5.5
CIP-004-6, Requirement R4, Part 4.1	CIP-007-6, Requirement R5, Part 5.6
CIP-004-6, Requirement R4, Part 4.2	CIP-007-6, Requirement R5, Part 5.7
CIP-004-6, Requirement R4, Part 4.3	CIP-009-6, Requirement R1, Part 1.1
CIP-004-6, Requirement R4, Part 4.4	CIP-009-6, Requirement R1, Part 1.2
CIP-004-6, Requirement R5, Part 5.1	CIP-009-6, Requirement R1, Part 1.3
CIP-004-6, Requirement R5, Part 5.2	CIP-009-6, Requirement R1, Part 1.4
CIP-004-6, Requirement R5, Part 5.3	CIP-009-6, Requirement R1, Part 1.5
CIP-004-6, Requirement R5, Part 5.4	CIP-009-6, Requirement R2, Part 2.1
CIP-004-6, Requirement R5, Part 5.5	CIP-009-6, Requirement R2, Part 2.2
CIP-005-5, Requirement R1, Part 1.5	CIP-009-6, Requirement R3, Part 3.1
CIP-006-6, Requirement R1, Part 1.2	CIP-009-6, Requirement R3, Part 3.2
CIP-006-6, Requirement R1, Part 1.3	CIP-010-2, Requirement R1, Part 1.1
CIP-006-6, Requirement R1, Part 1.4	CIP-010-2, Requirement R1, Part 1.2
CIP-006-6, Requirement R1, Part 1.5	CIP-010-2, Requirement R1, Part 1.3
CIP-006-6, Requirement R1, Part 1.8	CIP-010-2, Requirement R1, Part 1.4
CIP-006-6, Requirement R1, Part 1.9	CIP-010-2, Requirement R2, Part 2.1
CIP-007-6, Requirement R1, Part 1.1	CIP-010-2, Requirement R3, Part 3.1

CIP Reliability Standards Requirements and Parts	
CIP-007-6, Requirement R2, Part 2.1	CIP-010-2, Requirement R3, Part 3.3
CIP-007-6, Requirement R2, Part 2.2	CIP-010-2, Requirement R3, Part 3.4
CIP-007-6, Requirement R2, Part 2.3	CIP-011-2, Requirement R1, Part 1.1
CIP-007-6, Requirement R2, Part 2.4	CIP-011-2, Requirement R1, Part 1.2
CIP-007-6, Requirement R3, Part 3.1	CIP-011-2, Requirement R2, Part 2.1
CIP-007-6, Requirement R3, Part 3.2	CIP-011-2, Requirement R2, Part 2.2
CIP-007-6, Requirement R3, Part 3.3	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

June 9, 2017

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

RE: Correction of Links in WECC Regional Reliability Standards FAC-501-WECC-1 and PRC-004-WECC-2
Docket Nos. RM09-9-000 and RM15-13-000

Dear Ms. Bose:

This letter is to inform the Commission that, as a result of a reorganization of the Western Electricity Coordinating Council ("WECC") website, NERC has identified the need to update the web locations of certain Tables referenced in the Applicability Section of two mandatory and enforceable Regional Reliability Standards, FAC-501-WECC-1 (Transmission Maintenance) and PRC-004-WECC-2 (Protection System and Remedial Action Scheme Misoperation). Clean and redline versions of PRC-004-WECC-2 and FAC-501-WECC-1 showing the updated links on the WECC website are attached as **Attachment 1** and **Attachment 2**, respectively.

For completeness, NERC has also updated these links in inactive Regional Reliability Standards PRC-004-WECC-1 (Protection System and Remedial Action Scheme Misoperation) and TOP-007-1a (System Operating Limits), which are maintained on NERC's website.

NERC is not requesting Commission action on the instant filing. NERC submits the instant filing for informational purposes only.

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Atlanta, GA 30326
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Respectfully submitted,

/s/ Lauren A. Perotti

Lauren A. Perotti

Counsel for North American Electric Reliability Corporation

cc: Official service lists in Docket Nos. RM09-9-000, RM15-13-000

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service lists compiled by the Secretary in the above-referenced proceedings.

Dated at Washington, D.C. this 9th day of June, 2017.

/s/ Lauren A. Perotti

Lauren A. Perotti
Counsel for North American
Electric Reliability Corporation

ATTACHMENT 1

WECC Standard FAC-501-WECC-1 – Transmission Maintenance

A. Introduction

1. **Title:** Transmission Maintenance

2. **Number:** FAC-501-WECC-1

3. **Purpose:** To ensure the Transmission Owner of a transmission path identified in the table titled "Major WECC Transfer Paths in the Bulk Electric System" including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP); and performs and documents maintenance and inspection activities in accordance with the TMIP.

4. **Applicability**

   4.1 Transmission Owners that maintain the transmission paths in the most current table titled "Major WECC Transfer Paths in the Bulk Electric System" provided at:

   https://www.wecc.biz/Reliability/TableMajorPaths4-28-08.pdf.

5. **Effective Date:** July 1, 2011

B. Requirements

R.1. Transmission Owners shall have a TMIP detailing their inspection and maintenance requirements that apply to all transmission facilities necessary for System Operating Limits associated with each of the transmission paths identified in table titled "Major WECC Transfer Paths in the Bulk Electric System." *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R1.1. Transmission Owners shall annually review their TMIP and update as required. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R.2. Transmission Owners shall include the maintenance categories in Attachment 1-FAC-501-WECC-1 when developing their TMIP. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

R.3. Transmission Owners shall implement and follow their TMIP. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

C. Measures

M1. Transmission Owners shall have a documented TMIP per R.1.

M1.1 Transmission Owners shall have evidence they have annually reviewed their TMIP and updated as needed.

M2. Transmission Owners shall have evidence that their TMIP addresses the required maintenance details of R.2.

M3. Transmission Owners shall have records that they implemented and followed their TMIP as required in R.3. The records shall include:

1. The person or crew responsible for performing the work or inspection,
2. The date(s) the work or inspection was performed,
3. The transmission facility on which the work was performed, and
4. A description of the inspection or maintenance performed.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

The Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Self-certification conducted annually
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

The Reset Time Frame shall be one year.

1.3 Data Retention

The Transmission Owners shall keep evidence for Measure M1 through M3 for three years plus the current year, or since the last audit, whichever is longer.

1.4 Additional Compliance Information

No additional compliance information.

2. Violation Severity Levels

2.1. Lower: There shall be a Lower Level of non-compliance if any of the following conditions exist:

2.1.1 The TMIP does not include associated Facilities for one of the Paths identified in Attachment 1 FAC-501-WECC-1 as required by R.1 but Transmission Owners are performing maintenance and inspection for the missing Facilities.

2.1.2 Transmission Owners did not review their TMIP annually as required by R.1.1.

2.1.3 The TMIP does not include one maintenance category identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.1.4 Transmission Owners do not have maintenance and inspection records as required by R.3 but have evidence that they are implementing and following their TMIP.

2.2. Moderate: There shall be a Moderate Level of non-compliance if any of the following conditions exist:

2.2.1 The TMIP does not include associated Facilities for two of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.2.2 The TMIP does not include two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.2.3 Transmission Owners are not performing maintenance and inspection for one maintenance category identified in Attachment 1 FAC-501-WECC-1 as required in R3.

2.3. High: There shall be a High Level of non-compliance if any of the following condition exists:

2.3.1 The TMIP does not include associated Facilities for three of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.3.2 The TMIP does not include three maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.3.3 Transmission Owners are not performing maintenance and inspection for two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required in R3.

2.4. Severe: There shall be a Severe Level of non-compliance if any of the following condition exists:

2.4.1 The TMIP does not include associated Facilities for more than three of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.4.2 The TMIP does not exist or does not include more than three maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.4.3 Transmission Owners are not performing maintenance and inspection for more than two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required in R3.

Version History – Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for PRC-STD-005-1	
1	October 29, 2008	NERC BOT conditional approval	
1	April 21, 2011	FERC Approved in Order 751	
1	June 1, 2017	Link updated in the Applicability section of the standard (4.1)	

Attachment 1-FAC-501-WECC-1
Transmission Line and Station Maintenance Details

The maintenance practices in the TMIP may be performance-based, time-based, conditional based, or a combination of all three. The TMIP shall include:

1. A list of Facilities and associated Elements necessary to maintain the SOL for the transfer paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System;"
2. The scheduled interval for any time-based maintenance activities and/or a description supporting condition or performance-based maintenance activities including a description of the condition based trigger;
3. Transmission Line Maintenance Details:
   a. Patrol/Inspection
   b. Contamination Control
   c. Tower and wood pole structure management
4. Station Maintenance Details:
   a. Inspections
   b. Contamination Control
   c. Equipment Maintenance for the following:
      - Circuit Breakers
      - Power Transformers (including phase-shifting transformers)
      - Regulators
      - Reactive Devices (including, but not limited to, Shunt Capacitors, Series Capacitors, Synchronous Condensers, Shunt Reactors, and Tertiary Reactors)

A. Introduction

1. **Title:** Transmission Maintenance

2. **Number:** FAC-501-WECC-1

3. **Purpose:** To ensure the Transmission Owner of a transmission path identified in the table titled "Major WECC Transfer Paths in the Bulk Electric System" including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP); and performs and documents maintenance and inspection activities in accordance with the TMIP.

4. **Applicability**

   4.1 Transmission Owners that maintain the transmission paths in the most current table titled "Major WECC Transfer Paths in the Bulk Electric System" provided at: ~~http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf~~

   https://www.wecc.biz/Reliability/TableMajorPaths4-28-08.pdf.

5. **Effective Date:** ~~On the first day of the first quarter, after applicable regulatory approval.~~ July 1, 2011

B. Requirements

R.1. Transmission Owners shall have a TMIP detailing their inspection and maintenance requirements that apply to all transmission facilities necessary for System Operating Limits associated with each of the transmission paths identified in table titled "Major WECC Transfer Paths in the Bulk Electric System." *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R1.1. Transmission Owners shall annually review their TMIP and update as required. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R.2. Transmission Owners shall include the maintenance categories in Attachment 1-FAC-501-WECC-1 when developing their TMIP. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

R.3. Transmission Owners shall implement and follow their TMIP. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

C. Measures

M1. Transmission Owners shall have a documented TMIP per R.1.

M1.1 Transmission Owners shall have evidence they have annually reviewed their TMIP and updated as needed.

M2. Transmission Owners shall have evidence that their TMIP addresses the required maintenance details of R.2.

M3. Transmission Owners shall have records that they implemented and followed their TMIP as required in R.3. The records shall include:

1. The person or crew responsible for performing the work or inspection,
2. The date(s) the work or inspection was performed,
3. The transmission facility on which the work was performed, and
4. A description of the inspection or maintenance performed.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

The Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Self-certification conducted annually
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

The Reset Time Frame shall be one year.

1.3 Data Retention

The Transmission Owners shall keep evidence for Measure M1 through M3 for three years plus the current year, or since the last audit, whichever is longer.

1.4 Additional Compliance Information

No additional compliance information.

2. Violation Severity Levels

2.1. Lower: There shall be a Lower Level of non-compliance if any of the following conditions exist:

2.1.1 The TMIP does not include associated Facilities for one of the Paths identified in Attachment 1 FAC-501-WECC-1 as required by R.1 but Transmission Owners are performing maintenance and inspection for the missing Facilities.

2.1.2 Transmission Owners did not review their TMIP annually as required by R.1.1.

2.1.3 The TMIP does not include one maintenance category identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.1.4 Transmission Owners do not have maintenance and inspection records as required by R.3 but have evidence that they are implementing and following their TMIP.

2.2. Moderate: There shall be a Moderate Level of non-compliance if any of the following conditions exist:

2.2.1 The TMIP does not include associated Facilities for two of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.2.2 The TMIP does not include two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.2.3 Transmission Owners are not performing maintenance and inspection for one maintenance category identified in Attachment 1 FAC-501-WECC-1 as required in R3.

2.3. High: There shall be a High Level of non-compliance if any of the following condition exists:

2.3.1 The TMIP does not include associated Facilities for three of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.3.2 The TMIP does not include three maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.3.3 Transmission Owners are not performing maintenance and inspection for two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required in R3.

2.4. Severe: There shall be a Severe Level of non-compliance if any of the following condition exists:

2.4.1 The TMIP does not include associated Facilities for more than three of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.4.2 The TMIP does not exist or does not include more than three maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.4.3 Transmission Owners are not performing maintenance and inspection for more than two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required in R3.

Version History – Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for PRC-STD-005-1	
1	October 29, 2008	NERC BOT conditional approval	
1	April 21, 2011	FERC Approved in Order 751	
1	June 1, 2017	Link updated in the Applicability section of the standard (4.1)	

Attachment 1-FAC-501-WECC-1
Transmission Line and Station Maintenance Details

The maintenance practices in the TMIP may be performance-based, time-based, conditional based, or a combination of all three. The TMIP shall include:

1. A list of Facilities and associated Elements necessary to maintain the SOL for the transfer paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System;"
2. The scheduled interval for any time-based maintenance activities and/or a description supporting condition or performance-based maintenance activities including a description of the condition based trigger;
3. Transmission Line Maintenance Details:
   a. Patrol/Inspection
   b. Contamination Control
   c. Tower and wood pole structure management
4. Station Maintenance Details:
   a. Inspections
   b. Contamination Control
   c. Equipment Maintenance for the following:
      - Circuit Breakers
      - Power Transformers (including phase-shifting transformers)
      - Regulators
      - Reactive Devices (including, but not limited to, Shunt Capacitors, Series Capacitors, Synchronous Condensers, Shunt Reactors, and Tertiary Reactors)

ATTACHMENT 2

A. Introduction

1. Title: Protection System and Remedial Action Scheme Misoperation

2. Number: PRC-004-WECC-2

3. Purpose: Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

4. Applicability

4.1. Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled "Major WECC Transfer Paths in the Bulk Electric System" provided at https://www.wecc.biz/Reliability/TableMajorPaths4-28-08.pdf and "Major WECC Remedial Action Schemes (RAS)" provided at https://www.wecc.biz/Reliability/TableMajorRAS4-28-08.pdf.

4.2. Generator Owners that own RAS listed in the Table titled "Major WECC Remedial Action Schemes (RAS)" provided at https://wecc.biz/Reliability/TableMajorRAS4-28-08.pdf..

4.3. Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled "Major WECC Transfer Paths in the Bulk Electric System" provided at https://www.wecc.biz/Reliability/TableMajorPaths4-28-08.pdf and "Major WECC Remedial Action Schemes (RAS)" provided at https://www.wecc.biz/Reliability/TableMajorRAS4-28-08.pdf.

5. Effective Date: See Implementation Plan for the Revised Definition of "Remedial Action Scheme"

B. Requirements

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled "Major WECC Transfer Paths in the Bulk Electric System" and "Major WECC Remedial Action Schemes (RAS)."

R.1. System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

R1.1. System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.

R1.2. System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.

R.2. Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the Transmission Owner or Generator Owner identifies the Misoperation:

R2.1. If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection

System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R2.2. If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R2.2.1. Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.

R2.2.2. The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.

R2.3. If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R2.3.1. When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.

R2.3.2. When FERAS is not available, then

2.3.2.1. The Generator Owners shall adjust generation to a reliable operating level, or

2.3.2.2. Transmission Operators shall adjust the SOL and operate the facilities within established limits.

R2.4. If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.

R2.4.1. Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or

R2.4.2. Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

R.3. Transmission Owners and Generation Owners shall submit Misoperation incident reports to WECC within 10 business days for the following. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

R3.1. Identification of a Misoperation of a Protection System and/or RAS,

R3.2. Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

C. Measures

Each measure below applies directly to the requirement by number.

M1. Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.

M1.1 Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.

M1.2 Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.

M2. Transmission Owners and Generation Owners shall have evidence for the following.

M2.1 Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

M2.2 Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.

M2.2.1 Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

M2.2.2 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.

M2.3 The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.

M2.3.1 The Transmission Owner shall have evidence that it removed the associated Element from service.

M2.3.2 The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.

M2.4 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.

M2.4.1 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days of the misoperation identification.

M2.4.2 Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

M3. Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

M3.1 Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

M3.2 Completion of repair or replacement of Protection System and/or RAS that misoperated.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

1.2.1 The Performance-reset Period is one calendar month.

1.3 Data Retention

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R1

Lower	Moderate	High	Severe
System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days.	System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days.	System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days.	System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days.

R2.1 and R2.2.1

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.

R2.3

Lower	Moderate	High	Severe
The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.

R2.2.2 and R2.4

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days.

R3.1

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days.

R3.2

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion.

Version History — Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1	
1	April 21, 2011	FERC Order issued approving PRC-004-WECC-1 (approval effective June 27, 2011)	
2	November 13, 2014	Adopted by the NERC Board of Trustees	
2	November 19, 2015	FERC Order issued approving PRC-004-WECC-2. Docket No. RM15-13-000.	
2	May 26, 2017	All links were updated in the Applicability section of the standard (4.1, 4.2 and 4.3)	

A. Introduction

1. Title: Protection System and Remedial Action Scheme Misoperation

2. Number: PRC-004-WECC-2

3. Purpose: Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

4. Applicability

4.1. Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled "Major WECC Transfer Paths in the Bulk Electric System" provided at ~~http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf~~ https://www.wecc.biz/Reliability/TableMajorPaths4-28-08.pdf and "Major WECC Remedial Action Schemes (RAS)" provided at ~~http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf~~ https://www.wecc.biz/Reliability/TableMajorRAS4-28-08.pdf.~~-~~

4.2. Generator Owners that own RAS listed in the Table titled "Major WECC Remedial Action Schemes (RAS)" provided at https:// ~~http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf~~wecc.biz/Reliability/TableMajorRAS4-28-08.pdf..

4.3. Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled "Major WECC Transfer Paths in the Bulk Electric System" provided at https://www.wecc.biz/Reliability/TableMajorPaths4-28-08.pdf ~~http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf~~ and "Major WECC Remedial Action Schemes (RAS)" provided at https://www.wecc.biz/Reliability/TableMajorRAS4-28-08.pdf. ~~http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf.~~

5. Effective Date: See Implementation Plan for the Revised Definition of "Remedial Action Scheme"

B. Requirements

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled "Major WECC Transfer Paths in the Bulk Electric System" and "Major WECC Remedial Action Schemes (RAS)."

R.1. System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

R1.1. System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.

R1.2. System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.

R.2. Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully

compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the Transmission Owner or Generator Owner identifies the Misoperation:

R2.1. If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R2.2. If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R2.2.1. Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.

R2.2.2. The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.

R2.3. If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R2.3.1. When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.

R2.3.2. When FERAS is not available, then

2.3.2.1. The Generator Owners shall adjust generation to a reliable operating level, or

2.3.2.2. Transmission Operators shall adjust the SOL and operate the facilities within established limits.

R2.4. If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.

R2.4.1. Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or

R2.4.2. Transmission Owners or Generator Owners shall remove from service the

associated Element or RAS. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

R.3. Transmission Owners and Generation Owners shall submit Misoperation incident reports to WECC within 10 business days for the following. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

R3.1. Identification of a Misoperation of a Protection System and/or RAS,

R3.2. Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

C. Measures

Each measure below applies directly to the requirement by number.

M1. Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.

M1.1 Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.

M1.2 Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.

M2. Transmission Owners and Generation Owners shall have evidence for the following.

M2.1 Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

M2.2 Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.

M2.2.1 Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

M2.2.2 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.

M2.3 The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.

M2.3.1 The Transmission Owner shall have evidence that it removed the associated Element from service.

M2.3.2 The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.

M2.4 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.

M2.4.1 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days of the misoperation identification.

M2.4.2 Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

M3. Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

M3.1 Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

M3.2 Completion of repair or replacement of Protection System and/or RAS that misoperated.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

1.2.1 The Performance-reset Period is one calendar month.

1.3 Data Retention

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R1

Lower	Moderate	High	Severe
System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days.	System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days.	System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days.	System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days.

R2.1 and R2.2.1

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.

R2.3

Lower	Moderate	High	Severe
The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.

R2.2.2 and R2.4

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days.

R3.1

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days.

R3.2

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion.

Version History — Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1	
1	April 21, 2011	FERC Order issued approving PRC-004-WECC-1 (approval effective June 27, 2011)	
2	November 13, 2014	Adopted by the NERC Board of Trustees	
2	November 19, 2015	FERC Order issued approving PRC-004-WECC-2. Docket No. RM15-13-000.	
2	May 26, 2017	All links were updated in the Applicability section of the standard (4.1, 4.2 and 4.3)	

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR17-____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED REVISIONS TO THE RULES OF PROCEDURE

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June 26, 2017

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Exhibit A Clean and Redline Versions of Sections 600 and 900 to the NERC Rules of Procedure

Exhibit B Comments on Proposed Revisions

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR17-____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED REVISIONS TO THE RULES OF PROCEDURE

Pursuant to Section 215(f) of the Federal Power Act ("FPA")[1] and Section 39.10 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] requests approval of specific revisions to Sections 600 and 900 of the NERC Rules of Procedure ("ROP"). The purpose of these revisions is to: (i) clarify the scope of the Personnel Certification Program, the Training and Education Program and the Continuing Education Program; and (ii) streamline and align the language of the ROP with current practices of those programs. The clean and redlined versions of proposed ROP Sections 600 and 900 are attached herein as follows:

- **Exhibit A -** Clean and Redline Versions of Sections 600 and 900 to the NERC Rules of Procedure

For the reasons set forth in this petition, NERC respectfully requests that the Commission approve the proposed revisions as just, reasonable, not unduly discriminatory or preferential, in

[1] 16 U.S.C. § 824o (2012).

[2] 18 C.F.R. § 39.10 (2016).

[3] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61, 062 (2006) ("ERO Certification Order"), *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).

the public interest, and consistent with the Commission's regulations.

I. NOTICES AND COMMUNICATIONS

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

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II. REGULATORY FRAMEWORK

Section 215(f) of the FPA provides the regulatory framework for revisions to the NERC ROP, stating that "[t]he Electric Reliability Organization shall file with the Commission for approval any proposed rule or proposed rule change, accompanied by an explanation of its basis and purpose," and that the proposed rule or rule change "shall take effect upon a finding by the Commission, after notice and opportunity for comment, that the change is just, reasonable, and not unduly discriminatory or preferential, is in the public interest, and satisfies the requirements of subsection (c) [of § 215]." The Commission's regulations at 18 C.F.R. § 39.10 reiterate these requirements and also require that the filing include "a description of the proceedings conducted by the Electric Reliability Organization … to develop the proposal." The NERC ROP are Electric Reliability Organization ("ERO") rules as defined in Section 39.1 of the Commission's regulations.

III. PROPOSED REVISIONS

A. Proposed Revisions Summary

NERC proposes changes to Sections 600 and 900 of the ROP as part of its first comprehensive review to modernize and align the language of the ROP with current ERO practices. Specifically, through the proposed revisions NERC delineates the responsibilities, governance and scope of the Personnel Certification Program, the Training and Education Program and the Continuing Education Program. NERC also streamlines the ROP by eliminating detailed programmatic requirements duplicated in existing program manuals for the ERO.

B. Proposed Revisions Development

After developing the proposed revisions in collaboration with industry and Regional Entity representatives, NERC publicly posted two sets of revisions to Sections 600 and 900. The first 45-day public comment period for revisions to Section 600 were posted on May 16, 2016 through June 30, 2016. The second 45-day public comment period for revisions to Sections 600 and 900 were posted on November 9, 2016 through December 24, 2016. NERC received four (4) sets of comments from industry stakeholders in response to the first posting and eleven (11) sets of comments from industry stakeholders in response to the second posting.

As further discussed below, the commenters noted the following regarding the proposed revisions:

(1) address whether the removal of specific requirements for implementing the Personnel Certification Program and the Continuing Education Program from the ROP deprived stakeholders of due process;

(2) determine the appropriate frequency for reviewing the Personal Certification and

Governance ("PCGC") manual;

(3) identify the governance structure of the NERC Continuing Education Program;

(4) discern the relationship between Reliability Standards PER-003-1 (Operating Personnel Credentials), and PER-005-2 (Operations Personnel Training) and the Continuing Education Program (Section 902); and,

(5) re-examine the need for a non-discriminatory clause.

Comments were reviewed and are attached herein as **Exhibit C**. NERC, with input from Regional Entity representatives, addressed each comment. NERC posted a further revised draft of the ROP changes, incorporating comments received, and accompanying materials on the NERC website on April 26, 2017. This posting was completed at least (15) fifteen days prior to consideration of these revisions by the NERC Board of Trustees ("Board"), as contemplated in NERC's process for proposed revisions to the ROP. The posting included a document indicating how each comment received was considered.[4] On May 11, 2017 the NERC Board approved the proposed ROP revisions.

C. Proposed Revisions to Section 600

The proposed changes to ROP Section 600 relate to the scope, structure, and responsibilities of the Personnel Certification Program. NERC deletes or cross-references descriptions of examination requirements, dispute resolution procedures, and maintenance of certification credentials in the Personnel Certification Program manual. NERC also clarifies the PCGC's

[4] NERC, *Board of Trustees Package*, Agenda Item 8a (Attachment 2 – Consideration of Comments), (NERC Rules of Procedure Amendment – Proposed Revisions to Rules of Procedure Sections 600 and 900), (May 11, 2017), *available at* http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Meeting_May_11_2017_Agenda_Package_v2.pdf.

obligations to the public and employers of certified personnel. NERC seeks Commission approval of the following specific proposed revisions to Section 600 (*see* **Exhibit A**).

1. Section 601

In Section 601, NERC clarifies that the purpose of the Personnel Certification Program is to ensure that Bulk-Power System personnel, namely system operators, are qualified to operate the Bulk-Power System. Under the current program, NERC administers an examination and awards the credential to system operators who pass the examination to obtain the essential knowledge relating to NERC Reliability Standards and principles for Bulk-Power System operations. NERC highlights in the ROP that its Reliability Standards specify which personnel require certification pursuant to the NERC Personnel Certification Program.

2. Sections 602 and 603

NERC proposes to consolidate the contents of Sections 602 and 603 in Section 602, leaving Section 603 as a placeholder. Section 602 contains the governance authority and structure of the PCGC committee. Section 603 contains the procedural requirements for obtaining the system operator certification. In the revised Section 602, NERC deletes the governance authority and structure of the PCGC committee because this information is addressed verbatim in the PCGC charter. The PCGC charter is reviewed annually for updates and revisions are approved by the NERC Board. NERC also specifies that the PCGC must develop a certification program manual and outlines the mandatory elements of this manual. NERC proposes to eliminate programmatic detail for the manual from the ROP, as they are duplicated verbatim in the certification program manual. The certification program manual, like the PCGC charter, is reviewed regularly for updates. Revisions to the certification program manual are presented to the NERC Board. This streamlining allows program participants and NERC staff to only consult one resource for

certification requirements.

Commentators suggested identifying a specific frequency or timeframe for reviewing and updating the Personnel Certification Program manual. NERC proposes to allow the PCGC to retain flexibility to review and update the manual as necessary, rather than constrain the committee to a specific frequency. This strikes an appropriate balance of flexibility, in case the manual requires more frequent revisions, without committing to a specific frequency.

In Section 603, NERC proposes to delete the entire section on "Examination and Maintenance of NERC System Operator Certification Credential" because it contains procedural requirements for obtaining the system operator certification, which are duplicated verbatim in the Personnel Certification Program manual. Instead, in the revised Section 602, NERC notes that the manual must include "requirements for administering the system operation examinations," "requirements for exam eligibility," "requirements for awarding the Certification Credential," and "requirements for Certification Credential maintenance." Section 603 shall remain blank with a placeholder.

3. Sections 604 and 605

In Sections 604 and 605, NERC proposes to delete the programmatic detail regarding the dispute resolution process as well as disciplinary action. Instead, NERC proposes to cross-reference the same requirements as duplicated in the Personnel Certification Program manual. The certification program manual is reviewed regularly for updates and revisions are presented to the Board of Trustees.

Commenters questioned whether the removal of these requirements from the ROP would deprive stakeholders of the public notice and comment opportunities mandated when there are

changes to the ROP. NERC maintains that Section 215 of the FPA, the ROP and NERC Bylaws do not require NERC to provide a separate, formal public notice and opportunity to comment on changes to the Personnel Certification Program manual. Section 215 of the FPA requires Commission approval of (1) new or revised Reliability Standards, (2) transmission organizations that operate transmission facilities, (3) Reliability Standard violations, (4) new or revised delegation of functions to a regional entity, and, (5) new ERO rules and rule changes. Under Section 215, due process requirements apply to (1) the development of Reliability Standards, (2) changes to ERO rules and (3) penalties for violations of Reliability Standards.

NERC's Bylaws require the ERO to develop and implement rules, as in the judgment of the board, necessary or appropriate to carry out the purposes of the Corporation and its operations, including Rules of Procedure relating to personnel certification. The Bylaws further provide that the PCGC "shall have autonomy in developing and implementing system operation certification eligibility requirements, the development, administration, and scoring of the system operator assessment instruments, and operational processes" for the program. There is no requirement for notice and public comment for changes to Personnel Certification Program documents such as the manual. Even with this autonomy, the PCGC remains accountable to the NERC Board and to applicants of the program. Certification program manual changes will continue to be reported to the NERC Board. Furthermore, while changes to requirements in the manual do not require public notice and opportunity to comment, stakeholders are still able to provide input in developing these changes. The PCGC is comprised of industry representatives who develop changes to the manual and often meet several times a year to approve changes at public meetings.

4. Section 606

In Section 606, NERC clarifies that it is the PCGC's role to develop policies and procedures

to protect the integrity of the certification exam administered under the Personnel Certification Program. NERC also outlines how the PCGC periodically conducts reviews and studies to examine whether exams administered to candidates assess relevant knowledge and skills.

5. Section 607

In Section 607, NERC proposes ministerial changes to the types of information maintained and published about the Personnel Certification Program.

6. Section 608

In Section 608, NERC proposes to remove the requirement to include a statement of non-discrimination in program announcements. The PCGC issues the Certification Credential to any applicant who passes the examination and who has no conviction of any felony or misdemeanor directly related to his or her duties as a system operator. In its administration of the certification exam, the PCGC does not capture any protected class information. The only fields captured in the application relate to the geographic location and nature of the applicant's current job. Furthermore, NERC retains no records that could be used as bases for discriminating against certain groups of applicants when awarding credentials. As such, the elimination of the non-discriminatory clause is appropriate and further streamlines the certification program by removing superfluous language that does not redress a particular procedural gap or provide guidance on the implementation of the program.

7. Section 609

NERC proposes to rename Section 609 to clarify the responsibilities of the PCGC to employers of personnel certified pursuant to the Personnel Certification Program. NERC also proposes to remove language noting that the PCGC must demonstrate that the Credential applies to

any given specific set of daily occupational or professional duties. The exams administered pursuant to the Personnel Certification Program are solely designed to measure essential knowledge relating to NERC Reliability Standards and general principles of the Bulk-Power System. In addition, NERC streamlines other language in the section.

D. Proposed Revisions to Section 900

In Section 900, NERC updates and clarifies the scope and governance structure of the Training and Continuing Education Programs (*see* **Exhibit A**).

1. Section 901

In Section 901, NERC streamlines and updates the purpose of the Training and Education Program. Specifically, the purpose of the program is to oversee the coordination and delivery of training materials for both ERO Enterprise staff and industry participants. Training materials developed under this program will address delegation-related activities and other ERO functional program requirements. The program is not currently structured to directly deliver training to ERO Enterprise staff or industry stakeholders. Functional program staff, outside of the Training and Education Program, are responsible for delivering training to staff and industry stakeholders. They are also responsible for assessing the effectiveness of their training.

2. Section 902

In Section 902, NERC outlines the governance structure of the Continuing Education Program. Specifically, NERC identifies the governing body as the Personnel Subcommittee reporting to the NERC Operating Committee. The Personnel Subcommittee is responsible for developing and updating a manual. Similar to Section 600, NERC lists the required elements of the Continuing Education Program manual.

Certain commenters indicated that the development of Reliability Standards PER-003-1 (Operating Personnel Credentials) and PER-005-2 (Operations Personnel Training) is duplicative of Section 900. NERC notes that the purpose of Reliability Standard PER-003-1 is to require that Reliability Coordinators, Balancing Authorities and Transmission Operators get certified through the NERC System Operator Certification Program. The purpose of PER-005-2 is to require registered entities to develop training programs. As previously stated, the Training and Education Program does not directly deliver training to ERO Enterprise staff or industry. Registered entities are responsible for delivering their own training. To receive credit under the Continuing Education Program, a given course must be an approved learning activity and offered by an approved Continuing Education Provider. NERC clarifies that not all courses offered by registered entities pursuant to these training programs will qualify as learning activities nor will they all be offered by an approved Provider. Registered entities, including Reliability Coordinators, Balancing Authorities and Transmission Operators, may offer courses and train on topics relevant to various personnel, but they will not all fall under the umbrella of the Continuing Education Program.

IV. CONCLUSION

For the reasons set forth above, NERC requests that the Commission approve the proposed revisions to the NERC ROP included in **Exhibit A**. In addition, NERC requests that the proposed revisions be made effective upon Commission approval.

Respectfully submitted,

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Date: June 26, 2017

Exhibit A

Clean and Redline Versions of Sections 600 and 900 to the NERC Rules of Procedure

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rules of Procedure

Effective: [proposed date]

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SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE

NERC and NERC Members shall comply with these Rules of Procedure. Each Regional Entity shall comply with these Rules of Procedure as applicable to functions delegated to the Regional Entity by NERC or as required by an Applicable Governmental Authority or as otherwise provided.

Each Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities by approval pursuant to applicable legislation or regulation, or pursuant to agreement.

Any entity that is unable to comply or that is not in compliance with a NERC Rule of Procedure shall immediately notify NERC in writing, stating the Rule of Procedure of concern and the reason for not being able to comply with the Rule of Procedure.

NERC shall evaluate each case and inform the entity of the results of the evaluation. If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify the Applicable Governmental Authorities and take such other actions as NERC deems appropriate to address the situation.

NERC shall comply with each approved Reliability Standard that identifies NERC or the Electric Reliability Organization as a responsible entity. Regional Entities shall comply with each approved Reliability Standard that identifies Regional Entities as responsible entities. A violation by NERC or a Regional Entity of such a Reliability Standard shall constitute a violation of these Rules of Procedure.

SECTION 200 — DEFINITIONS OF TERMS

Definitions of terms used in the NERC Rules of Procedure are set forth in **Appendix 2**, *Definitions Used in the Rules of Procedure*.

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT

301. General

NERC shall develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable NERC and Regional Entities to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems. The Reliability Standards shall be technically excellent, timely, just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with other applicable standards of governmental authorities.

302. Essential Attributes for Technically Excellent Reliability Standards

1. **Applicability** — Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the Reliability Standard, with any specific additions or exceptions noted. Such functional classes[1] include: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, market operators, Planning Authorities, Transmission Planners, Resource Planners, and Distribution Providers. Each Reliability Standard shall also identify the geographic applicability of the Reliability Standard, such as the entire North American Bulk Power System, an Interconnection, or within a Region. A Reliability Standard may also identify any limitations on the applicability of the Reliability Standard based on electric Facility characteristics.

2. **Reliability Objectives** — Each Reliability Standard shall have a clear statement of purpose that shall describe how the Reliability Standard contributes to the reliability of the Bulk Power System. The following general objectives for the Bulk Power System provide a foundation for determining the specific objective(s) of each Reliability Standard:

    2.1 **Reliability Planning and Operating Performance** — Bulk Power Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.

    2.2 **Frequency and Voltage Performance** — The frequency and voltage of Bulk Power Systems shall be controlled within defined limits through the balancing of Real and Reactive Power supply and demand.

[1] These functional classes of entities are derived from NERC's Reliability Functional Model. When a Reliability Standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in NERC Reliability Standards.

2.3 **Reliability Information** — Information necessary for the planning and operation of reliable Bulk Power Systems shall be made available to those entities responsible for planning and operating Bulk Power Systems.

2.4 **Emergency Preparation** — Plans for emergency operation and system restoration of Bulk Power Systems shall be developed, coordinated, maintained, and implemented.

2.5 **Communications and Control** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of Bulk Power Systems.

2.6 **Personnel** — Personnel responsible for planning and operating Bulk Power Systems shall be trained and qualified, and shall have the responsibility and authority to implement actions.

2.7 **Wide-Area View** — The reliability of the Bulk Power Systems shall be assessed, monitored, and maintained on a Wide-Area basis.

2.8 **Security** — Bulk Power Systems shall be protected from malicious physical or cyber attacks.

3. **Performance Requirement or Outcome** — Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Power System, consistent with good utility practices and the public interest. Each Requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for Bulk Power System reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance Requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that Requirement. Each performance Requirement shall have one or more associated measures used to objectively evaluate compliance with the Requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations** — Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness** — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for Penalties and sanctions, as well as other ERO and Regional Entity compliance

documents, the consequences of violating a Reliability Standard are clearly presented to the entities responsible for complying with the Reliability Standards.

8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.

9. **Practicality** — Each Reliability Standard shall establish Requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology** — To the extent possible, Reliability Standards shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards development process.

303. Relationship between Reliability Standards and Competition

To ensure Reliability Standards are developed with due consideration of impacts on competition, to ensure Reliability Standards are not unduly discriminatory or preferential, and recognizing that reliability is an essential requirement of a robust North American economy, each Reliability Standard shall meet all of these market-related objectives:

1. **Competition** — A Reliability Standard shall not give any market participant an unfair competitive advantage.

2. **Market Structures** — A Reliability Standard shall neither mandate nor prohibit any specific market structure.

3. **Market Solutions** — A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.

4. **Commercially Sensitive Information** — A Reliability Standard shall not require the public disclosure of commercially sensitive information or other Confidential Information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.

5. **Adequacy** — NERC shall not set Reliability Standards defining an adequate amount of, or requiring expansion of, Bulk Power System resources or delivery capability.

304. Essential Principles for the Development of Reliability Standards

NERC shall develop Reliability Standards in accordance with the NERC *Standard Processes Manual*, which is incorporated into these Rules of Procedure as **Appendix 3A**. Appeals in connection with the development of a Reliability Standard shall also be conducted in accordance with the NERC *Standard Processes Manual*. Any amendments

or revisions to the *Standard Processes Manual* shall be consistent with the following essential principles:

1. **Openness** — Participation shall be open to all Persons and who are directly and materially affected by the reliability of the North American Bulk Power System. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

2. **Transparency** — The process shall be transparent to the public.

3. **Consensus-building** —The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any two Segments as defined in **Appendix 3D**, *Development of the Registered Ballot Body*, of these Rules of Procedure, and no single Segment, individual or organization shall be able to defeat a matter.

5. **Due Process** — Development of Reliability Standards shall provide reasonable notice and opportunity for any Person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.

6. **Timeliness** — Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

305. Registered Ballot Body

NERC Reliability Standards shall be approved by a Registered Ballot Body prior to submittal to the Board and then to Applicable Governmental Authorities for their approval, where authorized by applicable legislation or agreement. This Section 305 sets forth the rules pertaining to the composition of, and eligibility to participate in, the Registered Ballot Body.

1. **Eligibility to Vote on Reliability Standards** — Any person or entity may join the Registered Ballot Body to vote on Reliability Standards, whether or not such person or entity is a Member of NERC.

2. **Inclusive Participation** — The Segment qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the reliability of the Bulk Power System that can meet any one of the eligibility criteria for a Segment is entitled to

belong to and vote in each Segment for which it qualifies, subject to limitations defined in Sections 305.3 and 305.5.

3. **General Criteria for Registered Ballot Body Membership** — The general criteria for membership in the Segments are:

   3.1 **Multiple Segments** — A corporation or other organization with integrated operations or with affiliates that qualifies to belong to more than one Segment (e.g., Transmission Owners and Load-Serving Entities) may join once in each Segment for which it qualifies, provided that each Segment constitutes a separate membership and the organization is represented in each Segment by a different representative. Affiliated entities are collectively limited to one membership in each Segment for which they are qualified.

   3.2 **Withdrawing from a Segment or Changing Segments** — After its initial registration in a Segment, each registered participant may elect to withdraw from a Segment or apply to change Segments at any time.

   3.3 **Review of Segment Criteria** — The Board shall review the qualification guidelines and rules for joining Segments at least every three years to ensure that the process continues to be fair, open, balanced, and inclusive. Public input will be solicited in the review of these guidelines.

4. **Proxies for Voting on Reliability Standards** — Any registered participant may designate an agent or proxy to vote on its behalf. There are no limits on how many proxies an agent may hold. However, for the proxy to be valid, NERC must have in its possession written documentation signed by the representative of the registered participant that the voting right by proxy has been transferred from the registered participant to the agent.

5. **Segments** — The specific criteria for membership in each Registered Ballot Body Segment are defined in the *Development of the Registered Ballot Body* in **Appendix 3D.**

6. **Review of Segment Entries** — NERC shall review all applications for joining the Registered Ballot Body, and shall make a determination of whether the applicant's self-selection of a Segment satisfies at least one of the guidelines to belong to that Segment. The entity shall then become eligible to participate as a voting member of that Segment. The Standards Committee shall resolve disputes regarding eligibility for membership in a Segment, with the applicant having the right of appeal to the Board.

306. Standards Committee

The Standards Committee shall provide oversight of the Reliability Standards development process to ensure stakeholder interests are fairly represented. The Standards Committee shall not under any circumstance change the substance of a draft or approved Reliability Standard.

1. **Membership** — The Standards Committee is a representative committee comprising representatives of two members of each of the Segments in the Registered Ballot Body and two officers elected to represent the interests of the industry as a whole.

2. **Elections** — Standards Committee members are elected for staggered (one per Segment per year) two-year terms by the respective Segments in accordance with the *Procedure for the Election of Members of the NERC Standards Committee*, which is incorporated into these Rules of Procedure as **Appendix 3B**. Segments may use their own election procedure if such a procedure is ratified by two-thirds of the members of a Segment and approved by the Board.

3. **Canadian Representation**

   The Standards Committee will include Canadian representation as provided in **Appendix 3B**, *Procedure for the Election of Members of the NERC Standards Committee*.

4. **Open Meetings** — All meetings of the Standards Committee shall be open and publicly noticed on the NERC website.

307. Standards Process Management

NERC shall assign a standards process manager to administer the development of continent-wide Reliability Standards and a regional standards manager to administer the development of Regional Reliability Standards. The standards process manager shall be responsible for ensuring that the development and revision of Reliability Standards are in accordance with the NERC *Standard Processes Manual*. The standards process manager and the regional standards manager shall work to achieve the highest degree of integrity and consistency of quality and completeness of the Reliability Standards. The regional standards manager shall coordinate with any Regional Entities that develop Regional Reliability Standards to ensure those Regional Reliability Standards are effectively integrated with the NERC Reliability Standards.

308. Steps in the Development of Reliability Standards

1. **Procedure** — NERC shall develop Reliability Standards through the process set forth in the NERC *Standard Processes Manual* (**Appendix 3A**). The *Standard Processes Manual* includes provisions for developing Reliability Standards that can be completed using expedited processes, including a process to develop Reliability Standards to address national security situations that involve confidential issues.

2. **Board Adoption** — Reliability Standards or revisions to Reliability Standards approved by the ballot pool in accordance with the *Standard Processes Manual* shall be submitted for adoption by the Board. No Reliability Standard or revision to a Reliability Standard shall be effective unless adopted by the Board.

3. **Governmental Approval** — After Board adoption, a Reliability Standard or revision to a Reliability Standard shall be submitted to all Applicable Governmental Authorities in accordance with Section 309. No Reliability Standard or revision to a Reliability Standard shall be effective within a geographic area over which an Applicable Governmental Authority has jurisdiction unless it is approved by such Applicable Governmental Authority or is otherwise made effective pursuant to the laws applicable to such Applicable Governmental Authority.

309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities

1. **Filing of Reliability Standards for Approval** — Where authorized by applicable legislation or agreement, NERC shall file with the Applicable Governmental Authorities each Reliability Standard, modification to a Reliability Standard, or withdrawal of a Reliability Standard that is adopted by the Board. Each filing shall be in the format required by the Applicable Governmental Authority and shall include: a concise statement of the basis and purpose of the Reliability Standard; the text of the Reliability Standard; the implementation plan for the Reliability Standard; a demonstration that the Reliability Standard meets the essential attributes of Reliability Standards as stated in Section 302; the drafting team roster; the ballot pool and final ballot results; and a discussion of public comments received during the development of the Reliability Standard and the consideration of those comments.

2. **Remanded Reliability Standards and Directives to Develop Standards** — If an Applicable Governmental Authority remands a Reliability Standard to NERC or directs NERC to develop a Reliability Standard, NERC shall within five (5) business days notify all other Applicable Governmental Authorities, and shall within thirty (30) calendar days report to all Applicable Governmental Authorities a plan and timetable for modification or development of the Reliability Standard. Reliability Standards that are remanded or directed by an Applicable Governmental Authority shall be modified or developed using the *Standard Processes Manual*. NERC shall, during the development of a modification for the remanded Reliability Standard or directed Reliability Standard, consult with other Applicable Governmental Authorities to coordinate any impacts of the proposed Reliability Standards in those other jurisdictions. The expedited standards development process may be applied if necessary to meet a timetable for action required by the Applicable Governmental Authorities, respecting to the extent possible the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of

Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply.

3. **Directives to Develop Reliability Standards under Extraordinary Circumstances** — An Applicable Governmental Authority may, on its own initiative, determine that extraordinary circumstances exist requiring expedited development of a Reliability Standard. In such a case, the Applicable Governmental Authority may direct the development of a Reliability Standard within a certain deadline. NERC staff shall prepare the Standards Authorization Request. The proposed Reliability Standard will then proceed through the Reliability Standards development process, using the expedited action process described in the *Standard Processes Manual* as necessary to meet the specified deadline. The timeline will be developed to respect, to the extent possible, the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply, with appropriate modification of the timeline.

310. Annual Reliability Standards Development Plan

NERC shall develop and provide an annual Reliability Standards Development Plan for development of Reliability Standards to the Applicable Governmental Authorities. NERC shall consider the comments and priorities of the Applicable Governmental Authorities in developing and updating the annual Reliability Standards Development Plan. Each annual Reliability Standards Development Plan shall include a progress report comparing results achieved to the prior year's Reliability Standards Development Plan.

311. Regional Entity Standards Development Procedures

1. **NERC Approval of Regional Entity Reliability Standards Development Procedure** — To enable a Regional Entity to develop Regional Reliability Standards that are to be recognized and made part of NERC Reliability Standards, a Regional Entity may request NERC to approve a Regional Reliability Standards development procedure.

2. **Public Notice and Comment on Regional Reliability Standards Development Procedure** — Upon receipt of such a request, NERC shall publicly notice and request comment on the proposed Regional Reliability Standards development procedure, allowing a minimum of 45 days for comment. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to withdraw the request, revise the Regional Reliability Standards development procedure and request another posting for comment, or submit the

Regional Reliability Standards development procedure, along with its consideration of any objections received, for approval by NERC.

3. **Evaluation of Regional Reliability Standards Development Procedure** — NERC shall evaluate whether a Regional Reliability Standards development procedure meets the criteria listed below and shall consider stakeholder comments, any unresolved stakeholder objections, and the consideration of comments provided by the Regional Entity, in making that determination. If NERC determines the Regional Reliability Standards development procedure meets these requirements, the Regional Reliability Standards development procedure shall be submitted to the Board for approval. The Board shall consider the recommended action, stakeholder comments, any unresolved stakeholder comments, and the Regional Entity consideration of comments in determining whether to approve the Regional Reliability Standards development procedure.

   3.1 **Evaluation Criteria** — The Regional Reliability Standards development procedure shall be:

      3.1.1 **Open** — The Regional Reliability Standards development procedure shall provide that any person or entity who is directly and materially affected by the reliability of the Bulk Power Systems within the Regional Entity shall be able to participate in the development and approval of Reliability Standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the Regional Entity, a Regional Entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

      3.1.2 **Inclusive** — The Regional Reliability Standards development procedure shall provide that any Person with a direct and material interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process if adversely affected.

      3.1.3 **Balanced** — The Regional Reliability Standards development procedure shall have a balance of interests and shall not permit any two interest categories to dominate a matter or any single interest category to defeat a matter.

      3.1.4 **Due Process** — The Regional Reliability Standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the Regional Reliability Standards development procedure shall include public notice of the intent to develop a Regional Reliability Standard, a public comment period on the proposed Regional Reliability Standard,

due consideration of those public comments, and a ballot of interested stakeholders.

3.1.5 **Transparent** — All actions material to the development of Regional Reliability Standards shall be transparent. All Regional Reliability Standards development meetings shall be open and publicly noticed on the Regional Entity's website.

3.1.6 **Accreditation of Regional Standards Development Procedure** — A Regional Entity's Regional Reliability Standards development procedure that is accredited by the American National Standards Institute shall be deemed to meet the criteria listed in this Section 311.3.1, although such accreditation is not a prerequisite for approval by NERC.

3.1.7 **Use of NERC Procedure** — A Regional Entity may adopt the NERC *Standard Processes Manual* as the Regional Reliability Standards development procedure, in which case the Regional Entity's Regional Reliability Standards development procedure shall be deemed to meet the criteria listed in this Section 311.3.1.

4. **Revisions of Regional Reliability Standards Development Procedures** — Any revision to a Regional Reliability Standards development procedure shall be subject to the same approval requirements set forth in Sections 311.1 through 311.3.

5. **Duration of Regional Reliability Standards Development Procedures** — The Regional Reliability Standards development procedure shall remain in effect until such time as it is replaced with a new version approved by NERC or it is withdrawn by the Regional Entity. The Regional Entity may, at its discretion, withdraw its Regional Reliability Standards development procedure at any time.

312. Regional Reliability Standards

1. **Basis for Regional Reliability Standards** — Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard. Such Regional Reliability Standards shall in all cases be submitted to NERC for adoption and, if adopted, made part of the NERC Reliability Standards and shall be enforceable in accordance with the delegation agreement between NERC and the Regional Entity or other instrument granting authority over enforcement to the Regional Entity. No entities other than NERC and the Regional Entity shall be permitted to develop Regional Reliability Standards that are enforceable under statutory authority delegated to NERC and the Regional Entity.

2. **Regional Reliability Standards That are Directed by a NERC Reliability Standard** — Although it is the intent of NERC to promote uniform Reliability

Standards across North America, in some cases it may not be feasible to achieve a reliability objective with a Reliability Standard that is uniformly applicable across North America. In such cases, NERC may direct Regional Entities to develop Regional Reliability Standards necessary to implement a NERC Reliability Standard. Such Regional Reliability Standards that are developed pursuant to a direction by NERC shall be made part of the NERC Reliability Standards.

3. **Procedure for Developing an Interconnection-wide Regional Standard** — A Regional Entity organized on an Interconnection-wide basis may propose a Regional Reliability Standard for approval as a NERC Reliability Standard to be made mandatory for all applicable Bulk Power System owners, operators, and users within that Interconnection.

   3.1 **Presumption of Validity** — An Interconnection-wide Regional Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities, shall be adopted as a NERC Reliability Standard. NERC shall rebuttably presume that a Regional Reliability Standard developed, in accordance with a Regional Reliability Standards development process approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities.

   3.2 **Notice and Comment Procedure for Interconnection-wide Regional Reliability Standard** — NERC shall publicly notice and request comment on the proposed Interconnection-wide Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to comment on or withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for approval by NERC.

   3.3 **Adoption of Interconnection-wide Regional Reliability Standard by NERC** — NERC shall evaluate and recommend whether a proposed Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections that could serve as a basis for rebutting the presumption of validity of the Regional Reliability Standard. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning the proposed Regional Reliability Standard, shall have the option of

presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, NERC's recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

3.4 **Applicable Governmental Authority Approval** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

3.5 **Enforcement of Interconnection-wide Regional Reliability Standard** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

4. **Procedure for Developing Non-Interconnection-Wide Regional Reliability Standards** — Regional Entities that are not organized on an Interconnection-wide basis may propose Regional Reliability Standards to apply within their respective Regions. Such Regional Reliability Standards may be developed through the NERC Reliability Standards development procedure, or alternatively, through a Regional Reliability Standards development procedure that has been approved by NERC.

4.1 **No Presumption of Validity** — Regional Reliability Standards that are not proposed to be applied on an Interconnection-wide basis are not presumed to be valid but may be demonstrated by the proponent to be valid.

4.2 **Notice and Comment Procedure for Non-Interconnection-wide Regional Reliability Standards** — NERC shall publicly notice and request comment on the proposed Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to comment on or resolve any objections identified in the comments and may choose to withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for adoption by NERC.

4.3 **NERC Adoption of Non-Interconnection-wide Regional Reliability Standards** — NERC shall evaluate and recommend whether a proposed non-Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, the recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

4.4 **Applicable Governmental Authority Approval** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

4.5 **Enforcement of Non-Interconnection-wide Regional Reliability Standards** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

5. **Appeals** — A Regional Entity shall have the right to appeal NERC's decision not to adopt a proposed Regional Reliability Standard or Variance to the Commission or other Applicable Governmental Authority.

313. Other Regional Criteria, Guides, Procedures, Agreements, Etc.

1. **Regional Criteria** — Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy. Regional Criteria may include specific acceptable 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 authority delegated by NERC pursuant to delegation agreements and do not require NERC approval.

2. **Catalog of Regional Criteria** — NERC shall maintain a current catalog of Regional Criteria. Regional Entities shall provide a catalog listing of Regional Criteria to NERC and shall notify NERC of changes to the listing. Regional Entities shall provide any listed document to NERC upon written request.

314. Conflicts with Statutes, Regulations, and Orders

Notice of Potential Conflict — If a Bulk Power System owner, operator, or user determines that a NERC or Regional Reliability Standard may conflict with a function, rule, order, tariff, rate schedule, legislative requirement or agreement that has been accepted, approved, or ordered by a governmental authority affecting that entity, the entity shall expeditiously notify the governmental authority, NERC, and the relevant Regional Entity of the conflict.

1. **Determination of Conflict —** NERC, upon request of the governmental authority, may advise the governmental authority regarding the conflict and propose a resolution of the conflict, including revision of the Reliability Standard if appropriate.

2. **Regulatory Precedence** — Unless otherwise ordered by a governmental authority, the affected Bulk Power System owner, operator, or user shall continue to follow the function, rule, order, tariff, rate schedule, legislative requirement, or agreement accepted, approved, or ordered by the governmental authority until the governmental authority finds that a conflict exists and orders a remedy and such remedy is affected.

315. Revisions to NERC Standard Processes Manual

Any person or entity may submit a written request to modify NERC *Standard Processes Manual*. Consideration of the request and development of the revision shall follow the process defined in the NERC *Standard Processes Manual*. Upon approval by the Board, the revision shall be submitted to the Applicable Governmental Authorities for approval. Changes shall become effective only upon approval by the Applicable Governmental Authorities or on a date designated by the Applicable Governmental Authorities or as otherwise applicable in a particular jurisdiction.

316. Accreditation

NERC shall seek and maintain accreditation of the NERC Reliability Standards development process by the American National Standards Institute.

317. Periodic Review of Reliability Standards

NERC shall complete a periodic review of each NERC Reliability Standard in accordance with the NERC *Standard Processes Manual*. The standards process manager shall be responsible for administration of the periodic review of Reliability Standards. As a result of this review, the NERC Reliability Standard shall be reaffirmed, revised, or withdrawn. If the review indicates a need to revise or withdraw the Reliability Standard, a request for revision or withdrawal shall be prepared, submitted and addressed in accordance with the NERC *Standard Processes Manual*.

318. Coordination with the North American Energy Standards Board

NERC shall maintain a close working relationship with the North American Energy Standards Board and ISO/RTO Council to ensure effective coordination of wholesale electric business practice standards and market protocols with the NERC Reliability Standards.

319. Archived Standards Information

NERC shall maintain a historical record of Reliability Standards information that is no longer maintained on-line. For example, Reliability Standards that have been retired may be removed from the on-line system. Archived information shall be retained indefinitely as practical, but in no case less than six years or one complete Reliability Standards review cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by the NERC standards information manager of a written request.

320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels

1. **Development of Violation Risk Factors and Violation Severity Levels** — NERC shall follow the process for developing Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as set forth in the Standard Processes Manual, Appendix 3A to these Rules of Procedure.

2. **Remands of Directed Revision of VRFs and VSLs by Applicable Governmental Authorities** — If an Applicable Governmental Authority remands or directs a revision to a Board-approved VRF or VSL assignment, the NERC director of standards, after consulting with the standard drafting team, Standards Committee, and the NERC director of compliance operations, will recommend to the Board one of the following actions: (1) filing a request for clarification; (2) filing for rehearing or for review of the Applicable Governmental Authority decision; or (3) approval of the directed revisions to the VRF or VSL. If and to the extent time is available prior to the deadline for the Board's decision, an opportunity for interested parties to comment on the action taken will be provided.

3. **Alternative Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels** — In the event the Reliability Standards development process fails to produce Violation Risk Factors or Violation Severity Levels for a particular Reliability Standard in a timely manner, the Board of Trustees may approve Violation Risk Factors or Violation Severity Levels for that Reliability Standard after notice and opportunity for comment. In approving VRFs and VSLs, the Board shall consider the inputs of the Member Representatives Committee, affected stakeholders and NERC staff.

321. Special Rule to Address Certain Regulatory Directives

In circumstances where this Rule 321 applies, the Board of Trustees shall have the authority to take one or more of the actions set out below. The Board of Trustees shall have the authority to choose which one or more of the actions are appropriate to the circumstances and need not take these actions in sequential steps.

1. The Standards Committee shall have the responsibility to ensure that standards drafting teams address specific matters that are identified in directives issued by Applicable Governmental Authorities. If the Board of Trustees is presented with a proposed Reliability Standard that fails to address such directives, the Board of Trustees has the authority to remand, with instructions (including establishing a timetable for action), the proposed Reliability Standard to the Standards Committee.

2. Upon a written finding by the Board of Trustees that a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to remand the proposed Reliability Standard to the Standards Committee, with instructions to (i) convene a public technical conference to discuss the issues surrounding the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified; (ii) working with NERC staff, prepare a memorandum discussing the issues, an analysis of the alternatives considered and other appropriate matters; and (iii) re-ballot the proposed Reliability Standard one additional time, with such adjustments in the schedule as are necessary to meet the deadline contained in paragraph 2.1 of this Rule.

    2.1 Such a re-ballot shall be completed within forty-five (45) days of the remand. The Standards Committee memorandum shall be included in the materials made available to the ballot pool in connection with the re-ballot.

    2.2 In any such re-ballot, negative votes without comments related to the proposal shall be counted for purposes of establishing a quorum, but only affirmative votes and negative votes with comments related to the proposal shall be counted for purposes of determining the number of votes cast and whether the proposed Reliability Standard has been approved.

3. If the re-balloted proposed Reliability Standard achieves at least an affirmative two-thirds majority vote of the weighted Segment votes cast, with a quorum established, then the proposed Reliability Standard shall be deemed approved by the ballot pool and shall be considered by the Board of Trustees for approval.

4. If the re-balloted proposed Reliability Standard fails to achieve at least an affirmative two-thirds majority vote of the weighted Segment votes cast, but does

achieve at least a sixty percent affirmative majority of the weighted Segment votes cast, with a quorum established, then the Board of Trustees has the authority to consider the proposed Reliability Standard for approval under the following procedures:

4.1 The Board of Trustees shall issue notice of its intent to consider the proposed Reliability Standard and shall solicit written public comment particularly focused on the technical aspects of the provisions of the proposed Reliability Standard that address the specific matter identified in the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

4.2 The Board of Trustees may, in its discretion, convene a public technical conference to receive additional input on the matter.

4.3 After considering the developmental record, the comments received during balloting and the additional input received under paragraphs 4.1 and 4.2 of this Rule, the Board of Trustees has authority to act on the proposed Reliability Standard.

4.3.1 If the Board of Trustees finds that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to approve the proposed Reliability Standard and direct that it be filed with Applicable Governmental Authorities with a request that it be made effective.

4.3.2 If the Board of Trustees is unable to find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to treat the proposed Reliability Standard as a draft Reliability Standard and direct that the draft Reliability Standard and complete developmental record, including the additional input received under paragraphs 4.1 and 4.2 of this Rule, be filed with the Applicable Governmental Authorities as a compliance filing in response to the order giving rise to the regulatory directive, along with a recommendation that the Reliability Standard not be made effective and an explanation of the basis for the recommendation.

5. Upon a written finding by the Board of Trustees that standard drafting team has failed to develop, or a ballot pool has failed to approve, a proposed Reliability

Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to direct the Standards Committee (with the assistance of stakeholders and NERC staff) to prepare a draft Reliability Standard that addresses the regulatory directive, taking account of the entire developmental record pertaining to the matter. If the Standards Committee fails to prepare such draft Reliability Standard, the Board of Trustees may direct NERC management to prepare such draft Reliability Standard.

5.1 The Board of Trustees may, in its discretion, convene a public technical conference to receive input on the matter. The draft Reliability Standard shall be posted for a 45-day public comment period.

5.2 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees finds that the draft Reliability Standard, with such modifications as the Board of Trustees determines are appropriate in light of the comments received, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to approve the draft Reliability Standard and direct that the proposed Reliability Standard be filed with Applicable Governmental Authorities with a request that the proposed Reliability Standard be made effective.

5.3 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees is unable to find that the draft Reliability Standard, even with modifications, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to direct that the draft Reliability Standard and complete developmental record be filed as a compliance filing in response to the regulatory directive with the Applicable Governmental Authority issuing the regulatory directive, with a recommendation that the draft Reliability Standard not be made effective.

5.4 The filing of the Reliability Standard under either paragraph 5.2 or paragraph 5.3 of this Rule shall include an explanation of the basis for the decision by the Board of Trustees.

5.5 A Reliability Standard approved under paragraph 5 of this Rule shall not be eligible for submission as an American National Standard.

6. NERC shall on or before March 31st of each year file a report with Applicable Governmental Authorities on the status and timetable for addressing each outstanding directive to address a specific matter received from an Applicable Governmental Authority.

SECTION 400 — COMPLIANCE ENFORCEMENT

401. Scope of the NERC Compliance Monitoring and Enforcement Program

1. **Components of the NERC Compliance Monitoring and Enforcement Program** — NERC shall develop and implement a NERC Compliance Monitoring and Enforcement Program to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North American in which NERC and/or a Regional Entity (pursuant to a delegation agreement with NERC that has been approved by the Applicable Governmental Authority) has been given enforcement authority. There are four distinct parts of the NERC Compliance Monitoring and Enforcement Program: (1) NERC's oversight of the Regional Entity Compliance Monitoring and Enforcement Programs (Section 402), (2) the definition of the required Regional Entity Compliance Monitoring and Enforcement Program attributes (Section 403), (3) NERC's monitoring of Regional Entity compliance with Reliability Standards (Section 404), and (4) the monitoring of compliance with Reliability Standards that are applicable to NERC (Sections 405–406).

2. **Who Must Comply** — Where required by applicable legislation, regulation, rule or agreement, all Bulk Power System owners, operators, and users, Regional Entities, and NERC, are required to comply with all approved NERC Reliability Standards at all times. Regional Reliability Standards and Variances approved by NERC and the Applicable Governmental Authority shall be considered NERC Reliability Standards and shall apply to all Bulk Power System owners, operators, or users responsible for meeting those Reliability Standards within the Regional Entity boundaries, whether or not the Bulk Power System owner, operator, or user is a member of the Regional Entity.

3. **Data Access** — All Bulk Power System owners, operators, and users shall provide to NERC and the applicable Regional Entity such information as is necessary to monitor compliance with the Reliability Standards. NERC and the applicable Regional Entity will define the data retention and reporting requirements in the Reliability Standards and compliance reporting procedures.

4. **Role of Regional Entities in the Compliance Monitoring and Enforcement Program** — Each Regional Entity that has been delegated authority through a delegation agreement or other legal instrument approved by the Applicable Governmental Authority shall, in accordance with the terms of the approved delegation agreement, administer a Regional Entity Compliance Monitoring and Enforcement program to meet the NERC Compliance Monitoring and Enforcement Program goals and the requirements in this Section 400.

5. **Program Continuity** — NERC will ensure continuity of compliance monitoring and enforcement within the geographic boundaries of a Regional Entity in the event that NERC does not have a delegation agreement, or the Regional Entity withdraws from the agreement or does not operate its Compliance Monitoring and

Enforcement Program in accordance with the delegation agreement or other applicable requirements.

5.1 Should NERC not have a delegation agreement with a Regional Entity covering a geographic area, or a Regional Entity withdraws from an existing delegation agreement or the delegation agreement is otherwise terminated, NERC will directly administer the Compliance Monitoring and Enforcement Program applicable to owners, operators and users of the Bulk Power System within that geographic area.

1. This monitoring and enforcement will be accomplished by NERC and Compliance Staff from another approved Regional Entity.

2. If an existing delegation agreement with a Regional Entity is terminating, the Regional Entity shall promptly provide to NERC all relevant compliance information regarding Registered Entities, contacts, prior compliance information and actions, Mitigation Plans, and Remedial Action Directives for the period in which the Regional Entity was responsible for administering the Compliance Monitoring and Enforcement Program.

3. NERC will levy and collect all Penalties directly and will utilize any Penalty monies collected to offset the expenses of administering the Compliance Monitoring and Enforcement Program for the geographic area.

5.2 Should a Regional Entity seek to withdraw from its delegation agreement, NERC will seek agreement from another Regional Entity to amend its delegation agreement with NERC to extend that Regional Entity's boundaries for compliance monitoring and enforcement. In the event no Regional Entity is willing to accept this responsibility, NERC will administer the Compliance Monitoring and Enforcement Program within the geographical boundaries of the Regional Entity seeking to withdraw from the delegation agreement, in accordance with Section 401.5.1.

6. **Risk Elements** — NERC, with input from the Regional Entities, stakeholders, and regulators, shall at least annually identify risk elements to prioritize risks to the reliability of the Bulk Power System. These risk elements and related NERC Reliability Standards and Requirements are to be considered for compliance oversight in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan. NERC identifies the risk elements using data including, but not limited to: compliance findings; event analysis experience; data analysis; and the expert judgment of NERC and Regional Entity staff, committees, and subcommittees. NERC uses these risk elements to identify and prioritize interconnection and continent-wide risks to the reliability of the Bulk Power System. These identified risks, as well as risks to the reliability of the Bulk Power System identified by Regional Entities for their footprint, represent the

focus for monitoring activities in the upcoming year, and become inputs for developing oversight plans for individual Registered Entities. Compliance is required, and NERC and the Regional Entities have authority to monitor compliance, with all applicable NERC Reliability Standards whether or not they are identified as areas of focus to be considered for compliance oversight in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan or are included in a Regional Entity's oversight plan for the Registered Entity.

7. **Penalties, Sanctions, and Remedial Action Directives** — NERC and Regional Entities will apply Penalties, sanctions, and Remedial Action Directives that bear a reasonable relation to the seriousness of a violation and take into consideration timely remedial efforts as defined in the NERC *Sanction Guidelines*, which is incorporated into these rules as **Appendix 4B**.

8. **Multiple Enforcement Actions** – A Registered Entity shall not be subject to an enforcement action by NERC and a Regional Entity, or by more than one Regional Entity (unless the Registered Entity is registered in more than one Region in which the violation occurred), for the same violation.

9. **Records** — NERC shall maintain a record of each compliance submission, including Self-Reported, Possible, Alleged, and Confirmed Violations of approved Reliability Standards; associated Penalties, sanctions, Remedial Action Directives and settlements; and the status of mitigation actions.

10. **Confidential Information** — NERC will treat all Possible and Alleged Violations of Reliability Standards and matters related to a Compliance Monitoring and Enforcement Program process, including the status of any Compliance Investigation or other Compliance Monitoring and Enforcement Program process, as confidential in accordance with Section 1500.

    The types of information that will be considered confidential and will not (subject to statutory and regulatory requirements) be disclosed in any public information reported by NERC are identified in Section 1500. Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident, will be identified and protected from public disclosure as Critical Energy Infrastructure Information in accordance with Section 1500.

    The Regional Entity and NERC shall give Bulk Power System owners, operators, and users a reasonable opportunity to demonstrate that information concerning a violation is confidential before such report is disclosed to the public.

11. **Public Posting** — When the affected Bulk Power System owner, operator, or user either agrees with a Possible or Alleged Violation(s) of a Reliability Standard(s) or a report of a Compliance Audit or Compliance Investigation, or enters into a settlement agreement concerning a Possible or Alleged Violation(s), or the time for submitting an appeal is passed, or all appeals processes are complete, NERC

shall, subject to the confidentiality requirements of these Rules of Procedure, publicly post each Confirmed Violation, Penalty or sanction, settlement agreement, and final Compliance Audit or Compliance Investigation report, on its website. As required by an Applicable Governmental Authority, NERC will also post information concerning noncompliance disposed of as Compliance Exceptions, subject to Section 1500 of these Rules of Procedures.

11.1 Each Bulk Power System owner, operator, or user may provide NERC with a statement to accompany the Confirmed Violation or report to be posted publicly. The statement must be on company letterhead and include a signature, as well as the name and title of the person submitting the information.

11.2 In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information (*NERC Security Guidelines for the Electricity Sector — Protecting Potentially Sensitive Information* may be used as a guide) or other Confidential Information shall be redacted in accordance with Section 1500 and not be released publicly.

11.3 Subject to redaction of Critical Energy Infrastructure Information or other Confidential Information, for each Confirmed Violation or settlement relating to a Possible Violation or an Alleged Violation, the public posting shall include the name of any relevant entity, the nature, time period, and circumstances of such Possible, Alleged or Confirmed Violation, any Mitigation Plan or other Mitigating Activities to be implemented by the Registered Entity in connection with the Confirmed Violation or settlement, and sufficient facts to assist owners, operators and users of the Bulk Power System to evaluate whether they have engaged in or are engaging in similar activities.

12. **Violation Information Review** — NERC Compliance Staff shall periodically review and analyze all reports of Possible, Alleged and Confirmed Violations to identify trends and other pertinent reliability issues.

402. NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs

1. **NERC Monitoring Program** — NERC shall have a program to monitor the Compliance Monitoring and Enforcement Program of each Regional Entity that has been delegated authority. The objective of this monitoring program shall be to ensure that the Regional Entity carries out its Compliance Monitoring and Enforcement Program in accordance with these Rules of Procedure and the terms of the delegation agreement, and to ensure consistency and fairness of the Regional Entity's Compliance Monitoring and Enforcement Program. Oversight and monitoring by NERC shall be accomplished through an annual Compliance Monitoring and Enforcement Program review, program audits, and regular

evaluations of Regional Entity Compliance Monitoring and Enforcement Program performance as described below.

1.1 **NERC Review of Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans** — NERC shall require each Regional Entity to submit for review and approval an annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan. NERC shall review each annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan and shall accept the plan if it meets NERC requirements and the requirements of the delegation agreement.

1.2 **Regional Entity Compliance Monitoring and Enforcement Program Evaluation** — NERC shall annually evaluate the goals, tools, and procedures of each Regional Entity Compliance Monitoring and Enforcement Program to determine the effectiveness of each Regional Entity Compliance Monitoring and Enforcement Program, using criteria developed by the NERC Compliance and Certification Committee.

1.3 **Regional Entity Compliance Monitoring and Enforcement Program Audit** — At least once every five years, NERC shall conduct an audit to evaluate how each Regional Entity Compliance Monitoring and Enforcement Program implements the NERC Compliance Monitoring and Enforcement Program. The evaluation shall be based on these Rules of Procedure, including Appendix 4C, the delegation agreement, directives in effect pursuant to the delegation agreement, approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans, required Compliance Monitoring and Enforcement Program attributes, and the NERC Compliance Monitoring and Enforcement Program procedures. These evaluations shall be provided to the Applicable Governmental Authorities to demonstrate the effectiveness of each Regional Entity. In addition, audits of Cross-Border Regional Entities shall cover applicable requirements imposed on the Regional Entity by statute, regulation, or order of, or agreement with, provincial governmental and/or regulatory authorities for which NERC has auditing responsibilities over the Regional Entity's compliance with such requirements within Canada or Mexico. Participation of a representative of an Applicable Governmental Authority shall be subject to the limitations of sections 3.1.6 and 8.0 of Appendix 4C of these Rules of Procedure regarding disclosures of non-public compliance information related to other jurisdictions. NERC shall maintain an audit procedure containing the requirements, steps, and timelines to conduct an audit of each Regional Entity Compliance Monitoring and Enforcement Program. The current procedure is contained in the NERC Audit of Regional Entity Compliance Programs, which is incorporated into these rules as **Appendix 4A**.

1.3.1. NERC shall establish a program to audit bulk power system owners, operators, and users operating within a regional entity to verify the findings of previous compliance audits conducted by the regional entity to evaluate how well the regional entity compliance enforcement program is meeting its delegated authority and responsibility.

1.4 Applicable Governmental Authorities will be allowed to participate as an observer in any audit conducted by NERC of a Regional Entity's Compliance Monitoring and Enforcement Program. A representative of the Regional Entity being audited will be allowed to participate in the audit as an observer.

2. **Consistency Among Regional Compliance Monitoring and Enforcement Programs** — To provide for a consistent Compliance Monitoring and Enforcement Program for all Bulk Power System owners, operators, and users required to comply with approved Reliability Standards, NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program, which is incorporated into these rules of procedure as **Appendix 4C**. Any differences in Regional Entity Compliance Monitoring and Enforcement Program methods, including determination of violations and Penalty assessment, shall be justified on a case-by-case basis and fully documented in each Regional Entity delegation agreement.

2.1 NERC shall ensure that each of the Regional Entity Compliance Monitoring and Enforcement Programs meets these Rules of Procedure, including **Appendix 4C**, and follows the terms of the delegation agreement and the approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan.

2.2 NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program in **Appendix 4C** containing the procedures to ensure the consistency and fairness of the processes used to determine Regional Entity Compliance Monitoring and Enforcement Program findings of compliance and noncompliance, and the application of Penalties and sanctions.

2.3 NERC shall periodically conduct Regional Entity compliance manager forums. These forums shall use the results of Regional Entity Compliance Monitoring and Enforcement Program audits and findings of NERC Compliance Staff to identify and refine Regional Entity Compliance Monitoring and Enforcement Program differences into a set of best practices over time.

3. **Information Collection and Reporting** — NERC and the Regional Entities shall implement data management procedures that address data reporting requirements, data integrity, data retention, data security, and data confidentiality.

4. **Violation Disclosure** — NERC shall disclose all Confirmed Violations and maintain as confidential Possible Violations and Alleged Violations, according to the reporting and disclosure process in **Appendix 4C**.

5. **Authority to Determine Noncompliance, Levy Penalties and Sanctions, and Issue Remedial Action Directives** — NERC and Regional Entity Compliance Staff shall have the authority and responsibility to make initial determinations of compliance or noncompliance, and where authorized by the Applicable Governmental Authorities or where otherwise authorized, to determine Penalties and sanctions for noncompliance with a Reliability Standard, and issue Remedial Action Directives. Regional Entity boards or a compliance panel reporting directly to the Regional Entity board will be vested with the authority for the overall Regional Entity Compliance Monitoring and Enforcement Program and have the authority to impose Penalties and sanctions on behalf of NERC, where authorized by applicable legislation or agreement. Remedial Action Directives may be issued by NERC or a Regional Entity that is aware of a Bulk Power System owner, operator, or user that is, or is about to engage in an act or practice that would result, in noncompliance with a Reliability Standard, where such Remedial Action Directive is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat. If, after receiving such a Remedial Action Directive, the Bulk Power System owner, operator, or user does not take appropriate action to avert a violation of a Reliability Standard, NERC may petition the Applicable Governmental Authority to issue a compliance order.

6. **Due Process** — NERC shall establish and maintain a fair, independent, and nondiscriminatory appeals process. The appeals process is set forth in Sections 408-410. The process shall allow Bulk Power System owners, operators, and users to appeal the Regional Entity's findings of noncompliance and to appeal Penalties, sanctions, and Remedial Action Directives that are levied by the Regional Entity. Appeals beyond the NERC process will be heard by the Applicable Governmental Authority.

   The appeals process will also allow for appeals to NERC of any findings of noncompliance issued by NERC to a Regional Entity for Reliability Standards and Requirements where the Regional Entity is monitored for compliance to a Reliability Standard. No monetary Penalties will be levied in these matters; however sanctions, remedial actions, and directives to comply may be applied by NERC.

7. **Conflict Disclosure** — NERC shall disclose to the appropriate governmental authorities any potential conflicts between a market rule and the enforcement of a Regional Reliability Standard.

8. **Confidentiality** — To maintain the integrity of the NERC Compliance Monitoring and Enforcement Program, NERC and Regional Entity staff, Compliance Audit team members, and committee members shall maintain the

confidentiality of information obtained and shared during compliance monitoring and enforcement processes including Compliance Investigations, Compliance Audits, Spot Checks, drafting of reports, appeals, and closed meetings.

8.1 NERC and the Regional Entity shall have in place appropriate codes of conduct and confidentiality agreements for staff and other Compliance Monitoring and Enforcement Program participants.

8.2 Individuals not bound by NERC or Regional Entity codes of conduct who serve on compliance-related committees or Compliance Audit teams shall sign a NERC confidentiality agreement prior to participating on the committee or Compliance Audit team.

8.3 Information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall not be distributed outside of a committee or team, nor released publicly. Other information subject to confidentiality is identified in Section 1500.

8.4 In the event that a staff, committee, or Compliance Audit team member violates any of the confidentiality rules set forth above, the staff, committee, or Compliance Audit team member and any member organization with which the individual is associated may be subject to appropriate action by the Regional Entity or NERC, including prohibiting participation in future Compliance Monitoring and Enforcement Program activities.

9. **Auditor Training** — NERC shall develop and provide training in auditing skills to all people who participate in NERC and Regional Entity Compliance Audits. Training for NERC and Regional Entity personnel and others who serve as Compliance Audit team leaders shall be more comprehensive than training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

403. Required Attributes of Regional Entity Compliance Monitoring and Enforcement Programs

Each Regional Entity Compliance Monitoring and Enforcement Program shall promote excellence in the enforcement of Reliability Standards. To accomplish this goal, each Regional Entity Compliance Monitoring and Enforcement Program shall (i) conform to and comply with the NERC uniform Compliance Monitoring and Enforcement Program, **Appendix 4C** to these Rules of Procedure, except to the extent of any deviations that are stated in the Regional Entity's delegation agreement, and (ii) meet all of the attributes set forth in this Section 403.

Program Structure

1. **Independence** — Each Regional Entity's governance of its Compliance Monitoring and Enforcement Program shall exhibit independence, meaning the Compliance Monitoring and Enforcement Program shall be organized so that its compliance monitoring and enforcement activities are carried out separately from other activities of the Regional Entity. The Compliance Monitoring and Enforcement Program shall not be unduly influenced by the Bulk Power System owners, operators, and users being monitored or other Regional Entity activities that are required to meet the Reliability Standards. Regional Entities must include rules providing that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

2. **Exercising Authority** — Each Regional Entity Compliance Monitoring and Enforcement Program shall exercise the responsibility and authority in carrying out the delegated functions of the NERC Compliance Monitoring and Enforcement Program in accordance with delegation agreements and **Appendix 4C**. These functions include but are not limited to: data gathering, data reporting, Compliance Investigations, Compliance Audit activities, evaluating compliance and noncompliance, imposing Penalties and sanctions, and approving and tracking mitigation actions.

3. **Delegation of Authority** — To maintain independence, fairness, and consistency in the NERC Compliance Monitoring and Enforcement Program, a Regional Entity shall not sub-delegate its Compliance Monitoring and Enforcement Program duties to entities or persons other than the Regional Entity Compliance Staff, unless (i) required by statute or regulation in the applicable jurisdiction, or (ii) by agreement with express approval of NERC and of FERC or other Applicable Governmental Authority, to another Regional Entity.

4. **Hearings of Contested Findings or Sanctions —** The Regional Entity board or compliance panel reporting directly to the Regional Entity board (with appropriate recusal procedures) will be vested with the authority for conducting compliance hearings in which any Bulk Power System owner, operator, or user provided a Notice of Alleged Violation may present facts and other information to contest a Notice of Alleged Violation or any proposed Penalty, sanction, any Remedial Action Directive, or any Mitigation Plan component. Compliance hearings shall be conducted in accordance with the Hearing Procedures set forth in Attachment 2 to **Appendix 4C**. If a stakeholder body serves as the Hearing Body, no two industry sectors may control any decision and no single segment may veto any matter related to compliance after recusals.

Program Resources

5. **Regional Entity Compliance Staff** — Each Regional Entity shall have sufficient resources to meet delegated compliance monitoring and enforcement responsibilities, including the necessary professional staff to manage and implement the Regional Entity Compliance Monitoring and Enforcement Program.

6. **Regional Entity Compliance Staff Independence** — The Regional Entity Compliance Staff shall be capable of and required to make all determinations of compliance and noncompliance and determine Penalties, sanctions, and Remedial Action Directives and to review and accept Mitigation Plans and other Mitigating Activities.

   6.1 Regional Entity Compliance Staff shall not have a conflict of interest, real or perceived, in the outcome of compliance monitoring and enforcement processes, reports, or sanctions. The Regional Entity shall have in effect a conflict of interest policy.

   6.2 Regional Entity Compliance Staff shall have the authority and responsibility to carry out compliance monitoring and enforcement processes (with the input of industry subject matter experts), make determinations of compliance or noncompliance, and levy Penalties and sanctions without interference or undue influence from Regional Entity members and their representative or other industry entities.

   6.3 Regional Entity Compliance Staff may call upon independent technical subject matter experts who have no conflict of interest in the outcome of the compliance monitoring and enforcement process to provide technical advice or recommendations in the determination of compliance or noncompliance.

   6.4 Regional Entity Compliance Staff shall abide by the confidentiality requirements contained in Section 1500 and **Appendix 4C** of these Rules of Procedure, the NERC delegation agreement and other confidentiality agreements required by the NERC Compliance Monitoring and Enforcement Program.

   6.5 Contracting with independent consultants or others working for the Regional Entity Compliance Monitoring and Enforcement Program shall be permitted provided the individual has not received compensation from a Bulk Power System owner, operator, or user being monitored for a period of at least the preceding six months and owns no financial interest in any Bulk Power System owner, operator, or user being monitored for compliance to the Reliability Standard, regardless of where the Bulk Power System owner, operator, or user operates. Any such individuals for the purpose of these Rules of Procedure shall be considered as augmenting Regional Entity Compliance Staff.

7. **Use of Industry Subject Matter Experts and Regional Entity Members** — Industry experts and Regional Entity members may be called upon to provide their technical expertise in Compliance Monitoring and Enforcement Program activities.

7.1 The Regional Entity shall have procedures defining the allowable involvement of industry subject matter experts and Regional Entity members. The procedures shall address applicable antitrust laws and conflicts of interest.

7.2 Industry subject matter experts and Regional Entity members shall have no conflict of interest or financial interests in the outcome of their activities.

7.3 Regional Entity members and industry subject matter experts, as part of teams or Regional Entity committees, may provide input to the Regional Entity Compliance Staff so long as the authority and responsibility for (i) evaluating and determining compliance or noncompliance and (ii) levying Penalties, sanctions, or Remedial Action Directives shall not be delegated to any person or entity other than the Compliance Staff of the Regional Entity. Industry subject matter experts, Regional Entity members, or Regional Entity committees shall not make determinations of noncompliance or levy Penalties, sanctions, or Remedial Action Directives. Any committee involved shall be organized so that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

7.4 Industry subject matter experts and Regional Entity members shall sign a confidentiality agreement appropriate for the activity being performed.

7.5 All industry subject matter experts and Regional Entity members participating in Compliance Audits and Compliance Investigations shall successfully complete auditor training provided by NERC or the Regional Entity prior to performing these activities

Program Design

8. **Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan Content** — All approved Reliability Standards shall be included in the Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan for all Bulk Power System owners, operators, and users within the defined boundaries of the Regional Entity. Compliance to approved Regional Reliability Standards is applicable only within the Region of the Regional Entity that submitted those particular Regional Reliability Standards for approval. NERC will identify the risk elements and related Reliability Standards and Requirements to be considered by the Regional Entity in a given year in developing oversight plans for individual Registered Entities.

9. **Antitrust Provisions** — Each Regional Entity's Compliance Monitoring and Enforcement Program shall be structured and administered to abide by U.S. antitrust law and Canadian competition law.

10. **Information Submittal** — All Bulk Power System owners, operators, and users within the Regional Entity responsible for complying with Reliability Standards shall submit timely and accurate information when requested by the Regional Entity or NERC. NERC and the Regional Entities shall preserve any mark of confidentiality on information submitted pursuant to Section 1502.1.

    10.1 Each Regional Entity has the authority to collect the necessary information to determine compliance and shall develop processes for gathering data from the Bulk Power System owners, operators, and users the Regional Entity monitors.

    10.2 The Regional Entity or NERC has the authority to request information from Bulk Power System owners, operators, and users pursuant to Section 401.3 or this Section 403.10 without invoking a specific compliance monitoring and enforcement process in **Appendix 4C**, for purposes of determining whether to pursue one such process in a particular case and/or validating in the enforcement phase of a matter the conclusions reached through the compliance monitoring and enforcement process(es).

    10.3 When required or requested, the Regional Entities shall report information to NERC promptly and in accordance with **Appendix 4C** and other NERC procedures.

    10.4 Regional Entities shall notify NERC of all Possible, Alleged and Confirmed Violations of NERC Reliability Standards by Registered Entities over which the Regional Entity has compliance monitoring and enforcement authority, in accordance with **Appendix 4C**.

    10.5 A Bulk Power System owner, operator, or user found in noncompliance with a Reliability Standard shall submit a Mitigation Plan with a timeline addressing how the noncompliance will be corrected, unless an enforcement process is used that does not require a Mitigation Plan. The Regional Entity Compliance Staff shall review and accept the Mitigation Plan in accordance with **Appendix 4C**.

    10.6 An officer of a Bulk Power System owner, operator, or user shall certify as accurate all compliance data Self-Reported to the Regional Entity Compliance Monitoring and Enforcement Program.

    10.7 Regional Entities shall develop and implement procedures to verify the compliance information submitted by Bulk Power System owners, operators, and users.

11. **Compliance Audits of Bulk Power System Owners, Operators, and Users** — Each Regional Entity will maintain and implement a program of proactive Compliance Audits of Bulk Power System owners, operators, and users responsible for complying with Reliability Standards, in accordance with **Appendix 4C**. A Compliance Audit is a process in which a detailed review of the

activities of a Bulk Power System owner, operator, or user is performed to determine if that Bulk Power System owner, operator, or user is complying with approved Reliability Standards.

11.1 For an entity registered as a Balancing Authority, Reliability Coordinator, or Transmission Operator, the Compliance Audit will be performed at least once every three years. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, Compliance Audits shall be performed on a schedule established by NERC.

11.2 Compliance Audits of Balancing Authorities, Reliability Coordinators, and Transmission Operators will include a component at the audited entity's site. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, the Compliance Audit may be either an on-site Compliance Audit or based on review of documents, as determined to be necessary and appropriate by NERC or Regional Entity Compliance Staff.

11.3 Compliance Audits must include a detailed review of the activities of the Bulk Power System owner, operator, or user to determine if the Bulk Power System owner, operator, or user is complying with all approved Reliability Standards identified for audit by NERC. The Compliance Audit shall include a review of supporting documentation and evidence used by the Bulk Power System owner, operator or user to demonstrate compliance for an appropriate period prior to the Compliance Audit.

12. **Confidentiality of Compliance Monitoring and Enforcement Processes** — All compliance monitoring and enforcement processes, and information obtained from such processes, are to be non-public and treated as confidential in accordance with Section 1500 and **Appendix 4C** of these Rules of Procedure, unless NERC, the Regional Entity or FERC or another Applicable Governmental Authority with jurisdiction determines a need to conduct a Compliance Monitoring and Enforcement Program process on a public basis, provided, that NERC and the Regional Entities shall publish (i) schedules of Compliance Audits scheduled in each year, (ii) a public report of each Compliance Audit, and (iii) Notices of Penalty and settlement agreements. Advance authorization from the Applicable Governmental Authority is required to make public any compliance monitoring and enforcement process or any information relating to a compliance monitoring and enforcement process, or to permit interventions when determining whether to impose a Penalty. This prohibition on making public any compliance monitoring and enforcement process does not prohibit NERC or a Regional Entity from publicly disclosing (i) the initiation of or results from an analysis of a significant system event under Section 807 or of off-normal events or system performance under Section 808, or (ii) information of general applicability and usefulness to owners, operators, and users of the Bulk Power System concerning reliability and compliance matters, so long as specific allegations or conclusions

regarding Possible or Alleged Violations of Reliability Standards are not included in such disclosures.

13. **Critical Energy Infrastructure Information** — Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident will be identified and protected from public disclosure as Critical Energy Infrastructure Information. In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall be redacted according to NERC procedures and shall not be released publicly.

14. **Penalties, Sanctions, and Remedial Action Directives** — Each Regional Entity will apply all Penalties, sanctions, and Remedial Action Directives in accordance with the approved *Sanction Guidelines*, **Appendix 4B** to these Rules of Procedure. Any changes to the *Sanction Guidelines* to be used by any Regional Entity must be approved by NERC and submitted to the Applicable Governmental Authority for approval. All Confirmed Violations, Penalties, and sanctions, including Confirmed Violations, Penalties and sanctions specified in a Regional Entity Hearing Body decision, will be provided to NERC for review and filing with Applicable Governmental Authorities as a Notice of Penalty, in accordance with **Appendix 4C**.

15. **Regional Entity Hearing Process** — Each Regional Entity Compliance Monitoring and Enforcement Program shall establish and maintain a fair, independent, and nondiscriminatory process for hearing contested violations and any Penalties or sanctions levied, in conformance with Attachment 2 to **Appendix 4C** to these Rules of Procedure and any deviations therefrom that are set forth in the Regional Entity's delegation agreement. The hearing process shall allow Bulk Power System owners, operators, and users to contest findings of compliance violations, any Penalties and sanctions that are proposed to be levied, proposed Remedial Action Directives, and components of proposed Mitigation Plans. The Regional Entity hearing process shall be conducted before the Regional Entity board or a balanced committee established by and reporting to the Regional Entity board as the final adjudicator at the Regional Entity level, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions. The Regional Entity hearing process shall (i) include provisions for recusal of any members of the Hearing Body with a potential conflict of interest, real or perceived, from all compliance matters considered by the Hearing Body for which the potential conflict of interest exists and (ii) provide that no two industry sectors may control any decision and no single segment may veto any matter brought before the Hearing Body after recusals.

    Each Regional Entity will notify NERC of all hearings and NERC may observe any of the proceedings. Each Regional Entity will notify NERC of the outcome of all hearings.

    If a Bulk Power System owner, operator, or user or a Regional Entity has

completed the Regional Entity hearing process and desires to appeal the outcome of the hearing, the Bulk Power System owner, operator, or user or the Regional Entity shall appeal to NERC in accordance with Section 409 of these Rules of Procedure, except that a determination of violation or Penalty that has been directly adjudicated by an Applicable Governmental Authority shall be appealed with that Applicable Governmental Authority.

16. **Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan** — Each Regional Entity shall annually develop and submit to NERC for approval a Regional Entity Compliance Monitoring and Enforcement Implementation Plan in accordance with **Appendix 4C** that, includes details on regional risk assessment processes and results, Reliability Standards and Requirements associated with regional risk assessment results, the methods to be used by the Regional Entity for reporting, monitoring, evaluating, and assessing performance criteria and the Regional Entity's Annual Audit Plan. These Regional Implementation Plans will be submitted to NERC on the schedule established by NERC, generally on or about October 1 of the preceding year. In conjunction with the annual Regional Implementation Plan, each Regional Entity must report to NERC regarding how it carried out its delegated compliance monitoring and enforcement authority in the previous year, the effectiveness of the Compliance Monitoring and Enforcement Program, and changes expected to correct any deficiencies identified. Each Regional Entity will provide its annual report on the schedule established by NERC, generally on or about February 15 of the following year.

404. NERC Monitoring of Compliance for Regional Entities or Bulk Power Owners, Operator, or Users

NERC shall monitor Regional Entity compliance with NERC Reliability Standards and, if no there is no delegation agreement in effect with a Regional Entity for the geographic area, shall monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards. Industry subject matter experts may be used as appropriate in Compliance Investigations, Compliance Audits, and other Compliance Monitoring and Enforcement Program activities, subject to confidentiality, antitrust, and conflict of interest provisions.

1. **NERC Obligations** — NERC Compliance Staff shall monitor the compliance of the Regional Entity with the Reliability Standards for which the Regional Entities are responsible, in accordance with **Appendix 4C**. NERC shall actively monitor in its annual Compliance Enforcement and Monitoring Program selected Reliability Standards that apply to the Regional Entities. NERC shall evaluate compliance and noncompliance with all of the Reliability Standards that apply to the Regional Entities and shall impose sanctions, Penalties, or Remedial Action Directives when there is a finding of noncompliance. NERC shall post all violations of Reliability Standards that apply to the Regional Entities as described in the reporting and disclosure process in **Appendix 4C**.

In addition, NERC will directly monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards in any geographic area for which there is not a delegation agreement in effect with a Regional Entity, in accordance with **Appendix 4C**. In such cases, NERC will serve as the Compliance Enforcement Authority described in **Appendix 4C**. Compliance matters contested by Bulk Power System owners, operators, and users in such an event will be heard by the NERC Compliance and Certification Committee.

2. **Compliance Audit of the Regional Entity** — NERC shall perform a Compliance Audit of each Regional Entity responsible for complying with Reliability Standards at least once every three years. NERC shall make an evaluation of compliance based on the information obtained through the Compliance Audit. After due process is complete, the final Compliance Audit report shall be made public in accordance with the reporting and disclosure process in **Appendix 4C**.

3. **Appeals Process** — Any Regional Entity or Bulk Power System owner, operator or user found by NERC, as opposed to a Regional Entity, to be in noncompliance with a Reliability Standard may appeal the findings of noncompliance with Reliability Standards and any sanctions or Remedial Action Directives that are issued by, or Mitigation Plan components imposed by, NERC, pursuant to the processes described in Sections 408 through 410.

405. Monitoring of Reliability Standards and Other Requirements Applicable to NERC

The NERC Compliance and Certification Committee shall establish and implement a process to monitor NERC's compliance with the Reliability Standards that apply to NERC. The process shall use independent monitors with no conflict of interest, real or perceived, in the outcomes of the process. All violations shall be made public according to the reporting and disclosure process in **Appendix 4C**. The Compliance and Certification Committee will also establish a procedure for monitoring NERC's compliance with its Rules of Procedure for the Standards Development, Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs. Such procedures shall not be used to circumvent the appeals processes established for those programs.

406. Independent Audits of the NERC Compliance Monitoring and Enforcement Program

NERC shall provide for an independent audit of its Compliance Monitoring and Enforcement Program at least once every three years, or more frequently as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board. The independent audit shall meet the following minimum requirements and any other requirements established by the NERC Board.

1. **Effectiveness** — The audit shall evaluate the success and effectiveness of the NERC Compliance Monitoring and Enforcement Program in achieving its mission.

2. **Relationship** — The audit shall evaluate the relationship between NERC and the Regional Entity Compliance Monitoring and Enforcement Programs and the effectiveness of the programs in ensuring reliability.

3. **Final Report Posting** — The final report shall be posted by NERC for public viewing in accordance with **Appendix 4C**.

4. **Response to Recommendations** — If the audit report includes recommendations to improve the NERC Compliance Monitoring and Enforcement Program, the administrators of the NERC Compliance Monitoring and Enforcement Program shall provide a written response and plan to the Board within 30 days of the release of the final audit report.

407. Penalties, Sanctions, and Remedial Action Directives

1. **NERC Review of Regional Entity Penalties and Sanctions —** NERC shall review all Penalties, sanctions, and Remedial Action Directives imposed by each Regional Entity for violations of Reliability Standards, including Penalties, sanctions and Remedial Action Directives that are specified by a Regional Entity Hearing Body final decision issued pursuant to Attachment 2 to **Appendix 4C**, to determine if the Regional Entity's determination is supported by a sufficient record compiled by the Regional Entity, is consistent with the *Sanction Guidelines* incorporated into these Rules of Procedure as **Appendix 4B** and with other directives, guidance and directions issued by NERC pursuant to the delegation agreement, and is consistent with Penalties, sanctions and Remedial Action Directives imposed by the Regional Entity and by other Regional Entities for violations involving the same or similar facts and circumstances.

2. **Developing Penalties and Sanctions** — The Regional Entity Compliance Staff shall use the *Sanction Guidelines*, which are incorporated into these Rules of Procedure as **Appendix 4B**, to develop an appropriate Penalty, sanction, or Remedial Action Directive for a violation, and shall notify NERC of the Penalty, sanction or Remedial Action Directive.

3. **Effective Date of Penalty** — Where authorized by applicable legislation or agreement, no Penalty imposed for a violation of a Reliability Standard shall take effect until the thirty-first day after NERC files, with the Applicable Governmental Authority, a "Notice of Penalty" and the record of the proceedings in which the violation and Penalty were determined, or such other date as ordered by the Applicable Governmental Authority.

408. Review of NERC Decisions

1. **Scope of Review** — A Registered Entity or a Regional Entity wishing to challenge a finding of noncompliance and the imposition of a Penalty for a compliance measure directly administered by NERC, or a Regional Entity wishing to challenge a Regional Entity Compliance Monitoring and Enforcement Program audit finding, may do so by filing a notice of the challenge with NERC's

director of enforcement no later than 21 days after issuance of the notice of finding of violation or audit finding. Appeals by Registered Entities or Regional Entities of decisions of Regional Entity Hearing Bodies shall be pursuant to Section 409.

2. **Contents of Notice** — The notice of challenge shall include the full text of the decision that is being challenged, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief.

3. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of challenge, the NERC director of enforcement may file with the Hearing Panel a response to the issues raised in the notice, with a copy to the Regional Entity.

4. **Hearing by Compliance and Certification Committee** — The NERC Compliance and Certification Committee shall provide representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program an opportunity to be heard and shall decide the matter based upon the filings and presentations made, with a written explanation of its decision.

5. **Appeal** — The Regional Entity or Registered Entity may appeal the decision of the Compliance and Certification Committee by filing a notice of appeal with NERC's director of enforcement no later than 21 days after issuance of the written decision by the Compliance and Certification Committee. The notice of appeal shall include the full text of the written decision of the Compliance and Certification Committee that is being appealed, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not presented to the Compliance and Certification Committee.

6. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of appeal, the NERC Compliance Monitoring and Enforcement Program staff may file its response to the issues raised in the notice of appeal, with a copy to the entity filing the notice.

7. **Reply** — The entity filing the appeal may file a reply within 7 days.

8. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record, the response, and any reply. At its discretion, the Compliance Committee may invite representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program to appear before the Compliance Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

9. **Impartiality** — No member of the Compliance and Certification Committee or the Board of Trustees Compliance Committee having an actual or perceived conflict of interest in the matter may participate in any aspect of the challenge or appeal except as a party or witness.

10. **Expenses** — Each party in the challenge and appeals processes shall pay its own expenses for each step in the process.

11. **Non-Public Proceedings —** All challenges and appeals shall be closed to the public to protect Confidential Information.

409. Appeals from Final Decisions of Regional Entity Hearing Bodies

1. **Time for Appeal** — A Regional Entity acting as the Compliance Enforcement Authority, or an owner, operator or user of the Bulk Power System, shall be entitled to appeal from a final decision of a Regional Entity Hearing Body concerning an Alleged Violation of a Reliability Standard, a proposed Penalty or sanction for violation of a Reliability Standard, a proposed Mitigation Plan, or a proposed Remedial Action Directive, by filing a notice of appeal with NERC's director of enforcement, with copies to the Regional Entity and any other Participants in the Regional Entity Hearing Body proceeding, no later than 21 days after issuance of the final decision of the Regional Entity Hearing Body.

2. **Contents** — The notice of appeal shall include the full text of the final decision of the Regional Entity Hearing Body that is being appealed, a concise statement of the error or errors contained in the final decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not first presented during the proceeding before the Regional Entity Hearing Body.

3. **Response to Notice of Appeal** — Within 21 days after the date the notice of appeal is filed, the Regional Entity shall file the entire record of the Regional Entity Hearing Body proceeding with NERC's director of enforcement, with a copy to the Participant filing the notice. Within 35 days after the date of the notice of appeal, all Participants in the proceeding before the Regional Entity Hearing Body, other than the Participant filing the notice of appeal, shall file their responses to the issues raised in the notice of appeal.

4. **Reply** — The Registered Entity filing the appeal may file a reply to the responses within 7 days.

5. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record of the proceeding before the Regional Entity Hearing Body, the responses, and any reply filed with NERC. At its discretion, the Compliance Committee may invite representatives of the entity making the appeal and the other Participants in the proceeding before the Regional Entity Hearing Body to appear before the

Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

6. **Expenses** — Each party in the appeals process shall pay its own expenses for each step in the process.

7. **Non-Public Proceedings** — All appeals shall be closed to the public to protect Confidential Information.

8. **Appeal of Hearing Body Decisions Granting or Denying Motions to Intervene** — This section is not applicable to an appeal of a decision of a Regional Entity Hearing Body granting or denying a motion to intervene in the Regional Entity Hearing Body proceeding. Appeals of decisions of Regional Entity Hearing Bodies granting or denying motions to intervene in Regional Entity Hearing Body proceedings shall be processed and decided pursuant to Section 414.

410. Hold Harmless

A condition of invoking the challenge or appeals processes under Section 408 or 409 is that the entity requesting the challenge or appeal agrees that neither NERC (defined to include its Members, Board of Trustees, committees, subcommittees, staff and industry subject matter experts), any person assisting in the challenge or appeals processes, nor any company employing a person assisting in the challenge or appeals processes, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the challenge or appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards

A Registered Entity that is subject to an Applicable Requirement of a NERC Critical Infrastructure Protection Standard for which Technical Feasibility Exceptions are permitted, may request a Technical Feasibility Exception to the Requirement, and the request will be reviewed, approved or disapproved, and if approved, implemented, in accordance with the NERC *Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standard*, Appendix 4D to these Rules of Procedure.

412. Certification of Questions from Regional Entity Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee

1. A Regional Entity Hearing Body that is conducting a hearing concerning a disputed compliance matter pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, may certify to the Board of Trustees, for decision, a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the hearing in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by

the Compliance Committee appropriate, in accordance with Section 1.5.12 of the Hearing Procedures. All questions certified by a Regional Entity Hearing Body to the Board of Trustees shall be considered and disposed of by the Compliance Committee.

2. The Compliance Committee may accept or reject a certification of a question for decision. If the Compliance Committee rejects the certified question, it shall issue a written statement that the certification is rejected.

3. If the Compliance Committee accepts the certification of a question for decision, it shall establish a schedule by which the Participants in the hearing before the Regional Entity Hearing Body may file memoranda and reply memoranda stating their positions as to how the question certified for decision should be decided by the Compliance Committee. The Compliance Committee may also request, or provide an opportunity for, the NERC compliance operations department, the NERC compliance enforcement department, and/or the NERC general counsel to file memoranda stating their positions as to how the question certified for decision should be decided. After receiving such memoranda and reply memoranda as are filed in accordance with the schedule, the Compliance Committee shall issue a written decision on the certified question.

4. Upon receiving the Compliance Committee's written decision on the certified question, the Regional Entity Hearing Body shall proceed to complete the hearing in accordance with the Compliance Committee's decision.

5. The Compliance Committee's decision, if any, on the certified question shall only be applicable to the hearing from which the question was certified and to the Participants in that hearing.

413. Review and Processing of Regional Entity Hearing Body Final Decisions that Are Not Appealed

NERC shall review and process all final decisions of Regional Entity Hearing Bodies issued pursuant to Attachment 2 to Appendix 4C concerning an Alleged Violation, proposed Penalty or sanction, or proposed Mitigation Plan that are not appealed pursuant to Section 409, as though the determination had been made by the Regional Entity Compliance Monitoring and Enforcement Program. NERC shall review and process such final decisions, and may require that they be modified by the Regional Entity, in accordance with, as applicable to the particular decision, Sections 5.8, 5.9 and 6.5 of Appendix 4C.

414. Appeals of Decisions of Regional Entity Hearing Bodies Granting or Denying Motions to Intervene in Regional Entity Hearing Body Proceedings

1. **Time to Appeal** — An entity may appeal a decision of a Regional Entity Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** denying the entity's motion to intervene in a Regional Entity Hearing Body proceeding, and the Regional Entity Compliance Staff or any other Participant in the Regional Entity

Hearing Body proceeding may appeal a decision of the Regional Entity Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** granting or denying a motion to intervene in the Regional Entity Hearing Body proceeding, in either case by filing a notice of appeal with the NERC director of enforcement, with copies to the Regional Entity Clerk, the Regional Entity Hearing body, the Hearing Officer, the Regional Entity Compliance Staff, and all other Participants in the Regional Entity Hearing Body proceeding, no later than seven (7) days following the date of the Regional Entity Hearing Body decision granting or denying the motion to intervene.

2. **Contents of Notice of Appeal** — The notice of appeal shall set forth information and argument to demonstrate that the decision of the Regional Entity Hearing Body granting or denying the motion to intervene was erroneous under the grounds for intervention specified in Section 1.4.4 of Attachment 2 of **Appendix 4C** and that the entity requesting intervention should be granted or denied intervention, as applicable. Facts alleged in, and any offers of proof made in, the notice of appeal shall be supported by affidavit or verification. The notice of appeal shall include a copy of the original motion to intervene and a copy of the decision of the Regional Entity Hearing Body granting or denying the motion to intervene.

3. **Responses to Notice of Appeal** — Within ten (10) days following the date the notice of appeal is filed, the Regional Entity Clerk shall transmit to the NERC director of enforcement copies of all pleadings filed in the Regional Entity Hearing Body proceeding on the motion to intervene. Within fourteen (14) days following the date the notice of appeal is filed, the Regional Entity Hearing Body, the Regional Entity Compliance Staff, and any other Participants in the Regional Entity Hearing Body proceeding, may each file a response to the notice of appeal with the NERC director of enforcement. Within seven (7) days following the last day for filing responses, the entity filing the notice of appeal, and any Participant in the Regional Entity Hearing Body proceeding that supports the appeal, may file replies to the responses with the NERC director of enforcement.

4. **Disposition of Appeal** — The appeal shall be considered and decided by the Compliance Committee. The NERC director of enforcement shall provide copies of the notice of appeal and any responses and replies to the Compliance Committee. The Compliance Committee shall issue a written decision on the appeal; provided, that if the Compliance Committee does not issue a written decision on the appeal within forty-five (45) days following the date of filing the notice of appeal, the appeal shall be deemed denied and the decision of the Regional Entity Hearing Body granting or denying the motion to intervene shall stand. The NERC director of enforcement shall transmit copies of the Compliance Committee's decision, or shall provide notice that the forty-five (45) day period has expired with no decision by the Compliance Committee, to the Regional Entity Clerk, the Regional Entity Hearing Body, the entity filing the notice of appeal, the Regional Entity Compliance Staff, and any other Participants

in the Regional Entity Hearing Body proceeding that filed responses to the notice of appeal or replies to responses.

5. **Appeal of Compliance Committee Decision to FERC or Other Applicable Governmental Authority** — Any entity aggrieved by the decision of the Compliance Committee on an appeal of a Regional Entity Hearing Body decision granting or denying a motion to intervene in a Regional Entity Hearing Body proceeding (including a denial of such appeal by the expiration of the forty-five (45) day period as provided in Section 414.4) may appeal or petition for review of the decision of the Compliance Committee to FERC or to another Applicable Governmental Authority having jurisdiction over the matter, in accordance with the authorities, rules and procedures of FERC or such other Applicable Governmental Authority. Any such appeal or petition for review shall be filed within the time period, if any, and in the form and manner, specified by the applicable statutes, rules or regulations governing proceedings before FERC or the other Applicable Governmental Authority.

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION

501. Scope of the Organization Registration and Organization Certification Programs

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards. Registered Entities are not and do not become Members of NERC or a Regional Entity, by virtue of being listed on the NCR. Membership in NERC is governed by Article II of NERC's Bylaws; membership in a Regional Entity or regional reliability organization is governed by that entity's bylaws or rules.

The purpose of the Organization Certification Program is to ensure that the new entity (i.e., applicant to be an RC, BA, or TOP that is not already performing the function for which it is applying to be certified as) has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational.

Organization Registration and Organization Certification may be delegated to Regional Entities in accordance with the procedures in this Section 500; the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into these Rules of Procedure as **Appendix 5A**; and, approved Regional Entity delegation agreements or other applicable agreements.

1. **NERC Compliance Registry** — NERC shall establish and maintain the NCR of the Bulk Power System owners, operators, and users that are subject to approved Reliability Standards.

   1.1 (a) The NCR shall set forth the identity and functions performed for each organization responsible for meeting Requirements/sub-Requirements of the Reliability Standards. Bulk Power System owners, operators, and users (i) shall provide to NERC and the applicable Regional Entity information necessary to complete the Registration, and (ii) shall provide NERC and the applicable Regional Entity with timely updates to information concerning the Registered Entity's ownership, operations, contact information, and other information that may affect the Registered Entity's Registration status or other information recorded in the Compliance Registry.

   (b) A generation or transmission cooperative, a joint-action agency or another organization may register as a Joint Registration Organization (JRO), in lieu of each of the JRO's members or related entities being registered individually for one or more functions. Refer to Section 507.

(c) Multiple entities may each register using a Coordinated Functional Registration (CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility. Refer to Section 508.

1.2 In the development of the NCR, NERC and the Regional Entities shall determine which organizations should be placed on the NCR based on the criteria provided in the NERC *Statement of Compliance Registry Criteria* which is incorporated into these Rules of Procedure as **Appendix 5B**.

1.3 NERC and the Regional Entities shall use the following rules for establishing and maintaining the NCR based on the Registration criteria as set forth in **Appendix 5B** *Statement of Compliance Registry Criteria*:

1.3.1 NERC shall notify each organization that it is on the NCR. The Registered Entity is responsible for compliance with all the Reliability Standards applicable to the functions for which it is registered from the time it receives the Registration notification from NERC.

1.3.2 Any organization receiving such a notice may challenge its placement on the NCR according to the process in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section V.

1.3.3 The Compliance Committee of the Board of Trustees shall promptly issue a written decision on the challenge, including the reasons for the decision.

1.3.4 The decision of the Compliance Committee of the Board of Trustees shall be final unless, within 21 days of the date of the Compliance Committee of the Board of Trustees decision, the organization appeals the decision to the Applicable Governmental Authority.

1.3.5 Each Registered Entity identified on the NCR shall notify its corresponding Regional Entity(s) of any corrections, revisions, deletions, changes in ownership, corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards. Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards applicable to its associated Registration.

1.4 For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall:

1.4.1 Ensure that all areas are under the oversight of one and only one Reliability Coordinator.

1.4.2 Ensure that all Balancing Authorities and Transmission Operator entities[2] are under the responsibility of one and only one Reliability Coordinator.

1.4.3 Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator.

1.4.4 Ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority.

1.5 NERC shall maintain the NCR of organizations responsible for meeting the Requirements/sub-Requirements of the Reliability Standards currently in effect on its website and shall update the NCR monthly.

1.6 With respect to: (i) entities to be registered for the first time; (ii) currently-registered entities or (iii) previously-registered entities, for which registration status changes are sought, including availability and composition of a sub-set list of applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements), the registration process steps in Section III of **Appendix 5A** apply.

1.7 NERC shall establish a NERC-led, centralized review panel, comprised of a NERC lead with Regional Entity participants, in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III.D and **Appendix 5B**, *Statement of Compliance Registry Criteria*.

2. **Entity Certification** — NERC shall provide for Certification of all entities with primary reliability responsibilities requiring Certification. This includes those

[2] Some organizations perform the listed functions (e.g., Balancing Authority, Transmission Operator) over areas that transcend the Footprints of more than one Reliability Coordinator. Such organizations will have multiple Registrations, with each such Registration corresponding to that portion of the organization's overall area that is within the Footprint of a particular Reliability Coordinator.

entities that satisfy the criteria established in the NERC provisional Certification process. The NERC programs shall:

2.1 Evaluate and certify the competency of entities performing reliability functions. The entities presently expected to be certified include Reliability Coordinators, Transmission Operators, and Balancing Authorities.

2.2 Evaluate and certify each applicant's ability to meet the requirements for Certification.

2.3 Maintain process documentation.

2.4 Maintain records of currently certified entities.

2.5 Issue a Certification document to the applicant that successfully demonstrates its competency to perform the evaluated functions.

3. **Delegation and Oversight**

3.1 NERC may delegate responsibilities for Organization Registration and Organization Certification to Regional Entities in accordance with requirements established by NERC. Delegation will be via the delegation agreement between NERC and the Regional Entity or other applicable agreement. The Regional Entity shall administer Organization Registration and Organization Certification Programs in accordance with such delegations to meet NERC's programs goals and requirements subject to NERC oversight.

3.2 NERC shall develop and maintain a plan to ensure the continuity of Organization Registration and Organization Certification within the geographic or electrical boundaries of a Regional Entity in the event that no entity is functioning as a Regional Entity for that Region, or the Regional Entity withdraws as a Regional Entity, or does not operate its Organization Registration and Organization Certification Programs in accordance with delegation agreements.

3.3 NERC shall develop and maintain a program to monitor and oversee the NERC Organization Registration and Organization Certification Programs activities that are delegated to each Regional Entity through a delegation agreement or other applicable agreement.

3.3.1 This program shall monitor whether the Regional Entity carries out those delegated activities in accordance with NERC requirements, and whether there is consistency, fairness of administration, and comparability.

3.3.2 Monitoring and oversight shall be accomplished through direct participation in the Organization Registration and Organization Certification Programs with periodic reviews of documents and records of both programs.

502. Organization Registration and Organization Certification Program Requirements

1. NERC shall maintain the Organization Registration and Organization Certification Programs.

   1.1 The roles and authority of Regional Entities in the programs are delegated from NERC pursuant to the Rules of Procedure through regional delegation agreements or other applicable agreements.

   1.2 Processes for the programs shall be administered by NERC and the Regional Entities. Materials that each Regional Entity uses are subject to review and approval by NERC.

   1.3 The appeals process for the Organization Registration and Organization Certification Programs are identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Sections V and VI, respectively.

   1.4 The Certification Team membership is identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section IV.8.d.

2. To ensure consistency and fairness of the Organization Registration and Organization Certification Programs, NERC shall develop procedures to be used by all Regional Entities and NERC in accordance with the following criteria:

   2.1 NERC and the Regional Entities shall have data management processes and procedures that provide for confidentiality, integrity, and retention of data and information collected.

   2.2 Documentation used to substantiate the conclusions of the Regional Entity/ NERC related to Registration and/or Certification must be retained by the Regional Entity for (6) six years, unless a different retention period is otherwise identified, for the purposes of future audits of these programs.

   2.3 To maintain the integrity of the NERC Organization Registration and Organization Certification Programs, NERC, Regional Entities, Certification Team members, program audit team members (Section 506), and committee members shall maintain the confidentiality of information provided by an applicant or entities.

      2.2.1 NERC and the Regional Entities shall have appropriate codes of conduct and confidentiality agreements for staff, Certification

Team, Certification related committees, and Certification program audit team members.

2.2.2 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall maintain the confidentiality of any Registration or Certification-related discussions or documents designated as confidential (see Section 1500 for types of Confidential Information).

2.2.3 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall treat as confidential the individual comments expressed during evaluations, program audits and report-drafting sessions.

2.2.4 Copies of notes, draft reports, and other interim documents developed or used during an entity Certification evaluation or program audit shall be destroyed after the public posting of a final, uncontested report.

2.2.5 Information deemed by an applicant, entity, a Regional Entity, or NERC as confidential, including Critical Energy Infrastructure Information, shall not be released publicly or distributed outside of a committee or team.

2.2.6 In the event that an individual violates any of the confidentiality rules set forth above, that individual and any member organization with which the individual is associated will be subject to immediate dismissal from the audit team and may be prohibited from future participation in Compliance Monitoring and Enforcement Program activities by the Regional Entity or NERC.

2.2.7 NERC shall develop and provide training in auditing skills to all individuals prior to their participation in Certification evaluations. Training for Certification Team leaders shall be more comprehensive than the training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

2.4 An applicant that is determined to be competent to perform a function after completing all Certification requirements shall be deemed certified by NERC to perform that function for which it has demonstrated full competency.

2.4.1 All NERC certified entities shall be included on the NCR.

503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements

1. **Delegation** — Recognizing the Regional Entity's knowledge of and experience with their members, NERC may delegate responsibility for Organization Registration and Organization Certification to the Regional Entity through a delegation agreement.

2. **Registration** — The following Organization Registration activities shall be managed by the Regional Entity per the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into the Rules of Procedure as Appendix 5A *Organization Registration and Organization Certification Manual*:

   2.1 Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4).

3. **Certification —** The following Organization Certification activities shall be managed by the Regional Entity in accordance with an approved delegation agreement or another applicable agreement:

   3.1 An entity seeking Certification to perform one of the functions requiring Certification shall contact the Regional Entity for the Region(s) in which it plans to operate to apply for Certification.

   3.2 An entity seeking Certification and other affected entities shall provide all information and data requested by NERC or the Regional Entity to conduct the Certification process.

   3.3 Regional Entities shall notify NERC of all Certification applicants.

   3.4 NERC and/or the Regional Entity shall evaluate the competency of entities requiring Certification to meet the NERC Certification requirements.

   3.5 NERC or the Regional Entity shall establish Certification procedures to include evaluation processes, schedules and deadlines, expectations of the applicants and all entities participating in the evaluation and Certification processes, and requirements for Certification Team members.

      3.5.1 The NERC / Regional Entity Certification procedures will include provisions for on-site visits to the applicant's facilities to review the data collected through questionnaires, interviewing the operations and management personnel, inspecting the facilities and equipment (including requesting a demonstration of all tools identified in the Certification process), reviewing all necessary documents and data (including all agreements, processes, and procedures identified in the Certification process), reviewing

Certification documents and projected system operator work schedules, and reviewing any additional documentation needed to support the completed questionnaire or inquiries arising during the site visit.

3.5.2 The NERC/ Regional Entity Certification procedures will provide for preparation of a written report by the Certification Team, detailing any deficiencies that must be resolved prior to granting Certification, along with any other recommendations for consideration by the applicant, the Regional Entity, or NERC.

504. Appeals

1. NERC shall maintain an appeals process to resolve any disputes related to Registration or Certification activities per the *Organization Registration and Organization Certification Manual,* which is incorporated in these Rules of Procedure as Appendix 5A.

2. The Regional Entity Certification appeals process shall culminate with the Regional Entity board or a committee established by and reporting to the Regional Entity board as the final adjudicator, provided that where applicable, Canadian provincial governmental authorities may act as the final adjudicator in their jurisdictions. NERC shall be notified of all appeals and may observe any proceedings **(Appendix 5A** *Organization Registration and Organization Certification Manual*).

505. Program Maintenance

NERC shall maintain its program materials, including such manuals or other documents as it deems necessary, of the governing policies and procedures of the Organization Registration and Organization Certification Programs.

506. Independent Audit of NERC Organization Registration and Organization Certification Program

1. NERC, through the Compliance and Certification Committee, shall provide for an independent audit of its Organization Registration and Organization Certification Programs at least once every three years, or more frequently, as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board.

2. The audit shall evaluate the success, effectiveness and consistency of the NERC Organization Registration and Organization Certification Programs.

3. The final report shall be posted by NERC for public viewing.

4. If the audit report includes recommendations to improve the program, the administrators of the program shall provide a written response to the Board within 30 days of the final report, detailing the disposition of each and every

recommendation, including an explanation of the reasons for rejecting a recommendation and an implementation plan for the recommendations accepted.

507. Provisions Relating to Joint Registration Organizations (JRO)

1. In addition to registering as the entity responsible for all functions that it performs itself, an entity may register as a JRO on behalf of one or more of its members or related entities for one or more functions for which such members or related entities would otherwise be required to register and, thereby, accept on behalf of such members or related entities all compliance responsibility for that function or those functions including all reporting requirements. Any entity seeking to register as a JRO must submit a written agreement with its members or related entities for all Requirements/sub-Requirements for the function(s) for which the entity is registering for and takes responsibility for, which would otherwise be the responsibility of one or more of its members or related entities. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the JRO Registration.

2. The JRO Registration data must include the same Registration information as a normal compliance Registration entry. The JRO is responsible for providing all of the information and data, including submitting reports, as needed by the Regional Entity for performing assessments of compliance.

3. The Regional Entity shall notify NERC of each JRO that the Regional Entity accepts. The notification will identify the point of contact and the functions(s) being registered for on behalf of its members or related entities.

4. For purposes of Compliance Audits, the Regional Entity shall keep a list of all JROs. This document shall contain a list of each JRO's members or related entities and the function(s) for which the JRO is registered for that member(s) or related entity(s). It is the responsibility of the JRO to provide the Regional Entity with this information as well as the applicable JRO agreement(s).

5. The Regional Entity may request clarification of any list submitted to it that identifies the members of the JRO and may request such additional information as the Regional Entity deems appropriate.

6. The Regional Entity's acceptance of a JRO shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the JRO will meet the Registration requirements of Section 501(1.4).

7. NERC shall maintain, and post on its website, a JRO registry listing all JRO Registrations that have been reviewed and accepted by the Regional Entity. The posting shall identify the JRO entity taking compliance responsibilities for itself and its members.

8. The JRO shall inform the Regional Entity of any changes to an existing JRO. The Regional Entity shall promptly notify NERC of each such revision.

9. Nothing in Section 507 shall preclude a member of a JRO, a related entity, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the member or other entity is registering. A JRO member or related entity that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the JRO of its Registration.

508. Provisions Relating to Coordinated Functional Registration (CFR) Entities

1. In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.

2. Each CFR or each individual entity within a CFR must identify a point of contact that is responsible for providing information and data, including submitting reports as needed by the Regional Entity related to the CFR Registration.

3. The Regional Entity shall notify NERC of each CFR that the Regional Entity accepts.

4. NERC or the Regional Entity may request clarification of any list submitted to it that identifies the compliance responsibilities of the CFR and may request such additional information as NERC or the Regional Entity deems appropriate.

5. The Regional Entity's acceptance of that CFR shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the CFR will meet the Registration requirements of Section 501(1.4).

6. NERC shall maintain, and post on its website, a CFR registry listing all CFR Registrations that have been accepted by NERC or by a Regional Entity. The posting shall clearly list all the Reliability Standards or Requirements/sub-Requirements thereof for which each entity of the CFR is responsible for under the CFR.

7. The point of contact shall inform the Regional Entity of any changes to an existing CFR. The Regional Entity shall promptly notify NERC of each such revision.

8. In the event of a violation of a Reliability Standard or of a Requirement/sub-Requirement of a Reliability Standard for which an entity of a CFR is registered, that entity shall be identified in the Notice of Alleged Violation and shall be assessed the sanction or Penalty in accordance with the NERC Sanctions Guidelines. In the event a Regional Entity is not able to determine which entity(ies) is responsible for a particular Reliability Standard, or Requirements/sub-Requirements thereof that has been violated, the Regional Entity shall investigate the noncompliance in accordance with the NERC Rules of Procedure Section 400, *Compliance Enforcement*, to determine the entity(ies) to which the Regional Entity shall to issue the sanction or Penalty for the violation.

9. Nothing in Section 508 shall preclude an entity registered in a CFR, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the entity is registering. An entity registered in a CFR that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the point of contact of its Registration.

509. Exceptions to the Definition of the Bulk Electric System

An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered part of the Bulk Electric System.

SECTION 600 — PERSONNEL CERTIFICATION

601. Scope of Personnel Certification Program

Maintaining the reliability of the Bulk Power System through implementation of the Reliability Standards requires skilled and qualified personnel, including system operators. NERC shall develop a Personnel Certification Program to:

1. Provide the mechanism to determine system operators' essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. administer a system operator Certification exam; and

3. award the system operator Certification Credential to individuals who pass the exam.

The NERC Personnel Certification Program shall be international in scope consistent with the ERO's international regulatory responsibility for the reliability of the Bulk Power System in North America.

NERC Reliability Standards define which system operators require certification pursuant to the NERC Personnel Certification Program.

The NERC Personnel Certification Governance Committee (PCGC) is the governing body that establishes the policies, sets fees, and monitors the performance of the Personnel Certification Program for system operators.

602. Structure of ERO Personnel Certification Program

The PCGC shall develop and update, as necessary, a manual which describes the following:

1. requirements for administering the system operator examinations;

2. requirements for exam eligibility;

3. requirements for awarding the Certification Credential;

4. requirements for Certification Credential maintenance;

5. dispute resolution procedures; and

6. displicinary action guidelines.

603. [Placeholder]

604. Dispute Resolution Process

Any dispute arising under this Section or any NERC rules, policies, or procedures dealing with any segment of the Certification process shall be subject to the NERC System Operator Certification Dispute Resolution Process in the manual.

605. Disciplinary Action

NERC rules, policies, or procedures dealing with any segment of the Certification process shall be subject to the NERC System Operator Certification Disciplinary Action Process in the manual.

606. Candidate Testing

1. The PCGC shall develop exams to evaluate individual competence in a manner that is objective, and fair to all candidates, and to determine essential knowledge relating to NERC Reliability Standards as well as principles of the Bulk Power System operations.

2. The PCGC shall oversee exam administration as follows:

    2.1 Adopt and implement a formal policy of periodic review of exams to access ongoing relevance to knowledge and skill needed in the discipline; and

    2.2 Conduct ongoing studies to substantiate the reliability and validity of exams.

3. The PCGC shall develop and utilize policies and procedures to ensure the integrity and security of exams and the transparency of test administration consistent with the following:

    3.1 The PCGC shall establish pass/fail levels that protect the public with a method that is based on competence and generally accepted standards in the psychometric community as being fair and reasonable;

    3.2 The PCGC shall conduct ongoing studies to substantiate the reliability and validity of the exams;

    3.3 The PCGC shall dictate how long examination records are kept in their original format; and

    3.4 The PCGC shall demonstrate that different revisions of the exams assess equivalent content.

607. Public Information About the Personnel Certification Program

The PCGC shall maintain and publish the following:

1. a summary of the information, knowledge, or functions covered by each examination administered pursuant to the Personnel Certification Program; and.

2. an annual summary of Certification activities for the Personnel Certification Program, including, the number of examinations delivered, the number of applicants who passed, the number of applicants who failed, and the number of applicants certified.

608. Responsibilities to Applicants for Certification or Re-Certification

The PCGC shall adhere to the following with respect to personnel applicants:

1. comply with all requirements of applicable federal and state/provincial laws with respect to all Certification and re-Certification activities, and shall require compliance of all contractors and/or providers of services;

2. make available to all applicants copies of formalized procedures for application for, and attainment of, personnel Certification and re-Certification and shall uniformly follow and enforce such procedures for all applicants;

3. implement a formal policy for the periodic review of eligibility criteria and application procedures for fairness;

4. provide competently proctored examination sites; and

5. uniformly provide applicants with examination results and give content summary after the examination.

609. Responsibilities Employers of Certified Personnel

The PCGC shall adhere to the following with respect to certified personnel:

1. demonstrate that the exams adequately measure essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. award Certification and re-Certification only after the skill and knowledge of the individual have been evaluated and determined to be acceptable;

3. maintain, in an electronic format, a current list of those personnel certified in the programs and have policies and procedures that delineate what information about a Certification Credential holder may be made public and under what circumstances; and

4. develop formal policies and procedures for discipline of a Certification Credential holder, including the revocation of the certificate, for conduct deemed harmful to the public or inappropriate to the discipline (e.g., incompetence, unethical behavior, physical or mental impairment affecting performance). These procedures shall incorporate due process.

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members

1. All information made available or created during the course of any reliability readiness evaluation including, but not limited to, data, Documents, observations and notes, shall be maintained as confidential by all evaluation team members, in accordance with the requirements of Section 1500.

2. Evaluation team members are obligated to destroy all confidential evaluation notes following the posting of the final report of the reliability readiness evaluation.

3. NERC will retain reliability readiness evaluation-related documentation, notes, and materials for a period of time as defined by NERC.

4. These confidentiality requirements shall survive the termination of the NERC Reliability Readiness Evaluation and Improvement Program.

702. Formation of Sector Forum

1. NERC will form a sector forum at the request of any five members of NERC that share a common interest in the safety and reliability of the Bulk Power System. The members of sector forum may invite such others of the members of NERC to join the sector forum as the sector forum deems appropriate.

2. The request to form a sector forum must include a proposed charter for the sector forum. The Board must approve the charter.

3. NERC will provide notification of the formation of a sector forum to its membership roster. Notices and agendas of meetings shall be posted on NERC's website.

4. A sector forum may make recommendations to any of the NERC committees and may submit a Standards Authorization Request to the NERC *Reliability Standards Development Procedure*.

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS

801. Objectives of the Reliability Assessment and Performance Analysis Program

The objectives of the NERC Reliability Assessment and Performance Analysis Program are to: (1) conduct, and report the results of, an independent assessment of the overall reliability and adequacy of the interconnected North American Bulk Power Systems, both as existing and as planned; (2) analyze off-normal events on the Bulk Power System; (3) identify the root causes of events that may be precursors of potentially more serious events; (4) assess past reliability performance for lessons learned; (5) disseminate findings and lessons learned to the electric industry to improve reliability performance; and (6) develop reliability performance benchmarks. The final reliability assessment reports shall be approved by the Board for publication to the electric industry and the general public.

802. Scope of the Reliability Assessment Program

1. The scope of the Reliability Assessment Program shall include:

    1.1 Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.

    1.2 Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.

    1.3 Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.

    1.4 Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.

    1.5 Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.

2. The Reliability Assessment Program shall be performed in a manner consistent with the Reliability Standards of NERC including but not limited to those that specify reliability assessment Requirements.

803. Reliability Assessment Reports

The number and type of periodic assessments that are to be conducted shall be at the discretion of NERC. The results of the reliability assessments shall be documented in three reports: the long-term and the annual seasonal (summer) and the annual seasonal (winter) assessment reports. NERC shall also conduct special reliability assessments from time to time as circumstances warrant. The reliability assessment reports shall be reviewed and approved for publication by the Board. The three regular reports are described below.

1. **Long-Term Reliability Assessment Report** — The annual long-term report shall cover a ten-year planning horizon. The planning horizon of the long-term reliability assessment report shall be subject to change at the discretion of NERC. Detailed generation and transmission adequacy assessments shall be conducted for the first five years of the review period. For the second five years of the review period, the assessment shall focus on the identification, analysis, and projection of trends in peak demand, electric supply, and transmission adequacy, as well as other industry trends and developments that may impact future electric system reliability. Reliability issues of concern and their potential impacts shall be presented along with any mitigation plans or alternatives. The long-term reliability assessment reports will generally be published in the fall (September) of each year. NERC will also publish electricity supply and demand data associated with the long-term reliability assessment report.

2. **Summer Assessment Report** — The annual summer seasonal assessment report typically shall cover the four-month (June–September) summer period. It shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected summer peak demands. It shall also identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may include possible mitigation alternatives. The report will generally be published in mid-May for the upcoming summer period.

3. **Winter Assessment Report** — The annual winter seasonal assessment report shall cover the three-month (December–February) winter period. The report shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected winter peak demands. Similar to the summer assessment, the winter assessment shall identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may also include possible mitigation alternatives. The winter assessment report will generally be published in mid-November for the upcoming winter period.

4. **Special Reliability Assessment Reports** — In addition to the long-term and seasonal reliability assessment reports, NERC shall also conduct special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the Board or governmental authorities. The teams of reliability and technical experts also may initiate special assessments of key

reliability issues and their impacts on the reliability of a regions, subregions, or Interconnection (or a portion thereof). Such special reliability assessments may include, among other things, operational reliability assessments, evaluations of emergency response preparedness, adequacy of fuel supply, hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects or has the potential to affect the reliability of the interconnected Bulk Power Systems in North America.

804. Reliability Assessment Data and Information Requirements

To carry out the reviews and assessments of the overall reliability of the interconnected Bulk Power Systems, the Regional Entities and other entities shall provide sufficient data and other information requested by NERC in support of the annual long-term and seasonal assessments and any special reliability assessments.

Some of the data provided for these reviews and assessment may be considered confidential from a competitive marketing perspective, a Critical Energy Infrastructure Information perspective, or for other purposes. Such data shall be treated in accordance with the provisions of Section 1500 – Confidential Information.

While the major sources of data and information for this program are the Regional Entities, a team of reliability and technical experts is responsible for developing and formulating its own independent conclusions about the near-term and long-term reliability of the Bulk Power Systems.

In connection with the reliability assessment reports, requests shall be submitted to each of the Regional Entities for required reliability assessment data and other information, and for each Regional Entity's self-assessment report. The timing of the requests will be governed by the schedule for the preparation of the assessment reports.

The Regional Entity self-assessments are to be conducted in compliance with NERC Reliability Standards and the respective regional planning criteria. The team(s) of reliability and technical experts shall also conduct interviews with the Regional Entities as needed. The summary of the Regional Entity self-assessments that are to be included in the assessment reports shall follow the general outline identified in NERC's request. This outline may change from time to time as key reliability issues change.

In general, the Regional Entity reliability self-assessments shall address, among other areas, the following topics: demand and Net Energy for Load; assessment of projected resource adequacy; any transmission constraints that may impact bulk transmission adequacy and plans to alleviate those constraints; any unusual operating conditions that could impact reliability for the assessment period; fuel supply adequacy; the deliverability of generation (both internal and external) to Load; and any other reliability issues in the Region and their potential impacts on the reliability of the Bulk Power Systems.

805. Reliability Assessment Process

Based on their expertise, the review of the collected data, the review of the Regional Entity self-assessment reports, and interviews with the Regional Entities, as appropriate, the teams of reliability and technical experts shall perform an independent review and assessment of the generation and transmission adequacy of each Region's existing and planned Bulk Power System. The results of the review teams shall form the basis of NERC's long-term and seasonal reliability assessment reports. The review and assessment process is briefly summarized below.

1. **Resource Adequacy Assessment** — The teams shall evaluate the regional demand and resource capacity data for completeness in the context of the overall resource capacity needs of the Region. The team shall independently evaluate the ability of the Regional Entity members to serve their obligations given the demand growth projections, the amount of existing and planned capacity, including committed and uncommitted capacity, contracted capacity, or capacity outside of the Region. If the Region relies on capacity from outside of the Region to meet its resource objectives, the ability to deliver that capacity shall be factored into the assessment. The demand and resource capacity information shall be compared to the resource adequacy requirements of the Regional Entity for the year(s) or season(s) being assessed. The assessment shall determine if the resource information submitted represents a reasonable and attainable plan for the Regional Entity and its members. For cases of inadequate capacity or reserve margin, the Regional Entity will be requested to analyze and explain any resource capacity inadequacies and its plans to mitigate the reliability impact of the potential inadequacies. The analysis may be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable Regions. The results of these analyses shall be described in the assessment report.

2. **Transmission Adequacy and Operating Reliability Assessment** — The teams shall evaluate transmission system information that relates to the adequacy and operating reliability of the regional transmission system. That information shall include: regional planning study reports, interregional planning study reports, and/or regional operational study reports. If additional information is required, another data request shall be sent to the Regional Entity. The assessment shall provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the assessment period as required by NERC Reliability Standards. If sub-areas of the regional system are especially critical to the Reliable Operation of the regional bulk transmission system, these Facilities or sub-areas shall be reviewed and addressed in the assessment. Any areas of concern related to the adequacy or operating reliability of the system shall be identified and reported in the assessment.

3. **Seasonal Operating Reliability Assessment** — The team(s) shall evaluate the overall operating reliability of the regional bulk transmission systems. In areas with potential resource adequacy or system operating reliability problems,

operational readiness of the affected Regional Entities for the upcoming season shall be reviewed and analyzed. The assessment may consider unusual but possible operating scenarios and how the system is expected to perform. Operating reliability shall take into account a wide range of activities, all of which should reinforce the Regional Entity's ability to deal with the situations that might occur during the upcoming season. Typical activities in the assessment may include: facility modifications and additions, new or modified operating procedures, emergency procedures enhancement, and planning and operating studies. The teams shall report the overall seasonal operating reliability of the regional transmission systems in the annual summer and winter assessment reports.

4. **Reporting of Reliability Assessment Results** — The teams of reliability and technical experts shall provide an independent assessment of the reliability of the Regional Entities and the North American interconnected Bulk Power System for the period of the assessment. While the Regional Entities are relied upon to provide the information to perform such assessments, the review team is not required to accept the conclusions provided by the Regional Entities. Instead, the review team is expected, based on their expertise, to reach their own independent conclusions about the status of the adequacy of the generation and bulk power transmission systems of North America.

   The review team also shall strive to achieve consensus in their assessments. The assessments that are made are based on the best information available at the time. However, since judgment is applied to this information, legitimate differences of opinion can develop. Despite these differences, the review team shall work to achieve consensus on their findings.

   In addition to providing long-term and seasonal assessments in connection with the Reliability Assessment Program, the review team of experts shall also be responsible for recommending new and revised Reliability Standards related to the reliability assessments and the reliability of the Bulk Power Systems. These proposals for new or revised Reliability Standards shall be entered into NERC's Reliability Standards development process.

   Upon completion of the assessment, the team shall share the results with the Regional Entities. The Regional Entities shall be given the opportunity to review and comment on the conclusions in the assessment and to provide additional information as appropriate. The reliability assessments and their conclusions are the responsibility of NERC's technical review team and NERC.

   The preparation and approval of NERC's reliability assessment reports shall follow a prescribed schedule including review, comment, and possible approval by appropriate NERC committees. The long-term and seasonal (summer and winter) reliability assessment reports shall be further reviewed for approval by the Board for publication to the electric industry.

806. Scope of the Reliability Performance and Analysis Program

The components of the program will include analysis of large-scale outages, disturbances, and near misses to determine root causes and lessons learned; identification and continuous monitoring of performance indices to detect emerging trends and signs of a decline in reliability performance; and communications of performance results, trends, recommendations, and initiatives to those responsible to take actions; followed with confirmation of actions to correct any deficiencies identified. Within NERC, the reliability performance program will provide performance results to the Reliability Standards Development and Compliance Monitoring and Enforcement Programs to make the necessary adjustments to preserve reliability based on a risk-based approach.

807. Analysis of Major Events

Responding to major events affecting the Bulk Power System such as significant losses of Load or generation, significant Bulk Power System disturbances, or other emergencies on the Bulk Power System, can be divided into four phases: situational assessment and communications; situation tracking and communications; data collection, investigation, analysis, and reporting; and follow-up on recommendations.

1. NERC's role following a major event is to provide leadership, coordination, technical expertise, and assistance to the industry in responding to the major event. Working closely with the Regional Entities and Reliability Coordinators, and other appropriate Registered Entities, NERC will coordinate and facilitate efforts among industry participants, and with state, federal, and provincial governments in the United States and Canada to support the industry's response.

2. When responding to any major event where physical or cyber security is suspected as a cause or contributing factor to the major event, NERC will immediately notify appropriate government agencies and coordinate its activities with them.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator of the Bulk Power System shall also provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entity as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

4. During the conduct of NERC analyses, assistance may be needed from government agencies. This assistance could include: authority to require data reporting from affected or involved parties; communications with other agencies of government; investigations related to possible criminal or terrorist involvement in the major event; resources for initial data gathering immediately after the major

event; authority to call meetings of affected or involved parties; and technical and analytical resources for studies.

5. NERC shall work with all other participants to establish a clear delineation of roles, responsibilities, and coordination requirements among industry and government for the investigation and reporting of findings, conclusions, and recommendations related to major events with the objective of avoiding, to the extent possible, multiple investigations of the same major event. If the major event is confined to a single Regional Entity, NERC representatives will participate as members of the Regional Entity analysis team. NERC will establish, maintain, and revise from time to time as appropriate based on experience, a manual setting forth procedures and protocols for communications and sharing and exchange of information between and among NERC, the affected Regional Entity or Entities, and relevant governmental authorities, industry organizations and Bulk Power System user, owners, and operators concerning the investigation and analysis of major events.

6. NERC and applicable entity(s) will apply, as appropriate to the circumstances of the major event, the NERC *Blackout and Disturbance Response Procedures*, which are incorporated into these Rules of Procedure as **Appendix 8**. These procedures provide a framework to guide NERC's response to major events that may have multiregional, national, or international implications. Experienced industry leadership shall be applied to tailor the response to the specific circumstances of the major event. In accordance with those procedures, the NERC president will determine whether the major event warrants analysis at the NERC level. A Regional Entity may request that NERC elevate any analysis of a major event to the NERC level.

7. NERC will screen and analyze the findings and recommendations from the analysis, and those with generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities

1. NERC and Regional Entities will analyze Bulk Power System and equipment performance occurrences that do not rise to the level of a major event, as described in Section 807. NERC and Regional Entities will also analyze potential vulnerabilities in the Bulk Power System that they discover or that are brought to their attention by other sources including government agencies. The purpose of these analyses is to identify the root causes of occurrences or conditions that may be precursors of major events or other potentially more serious occurrences, or that have the potential to cause major events or other more serious occurrences, to assess past reliability performance for lessons learned, and to develop reliability performance benchmarks and trends.

2. NERC and Regional Entities will screen and analyze off-normal occurrences, Bulk Power System performance, and potential Bulk Power System vulnerabilities for significance, and information from those indicated as having generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator, of the Bulk Power System shall provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entities as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

809. Reliability Benchmarking

NERC shall identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include assessing available metrics, developing guidelines for acceptable metrics, maintaining a performance metrics "dashboard" on the NERC website, and developing appropriate reliability performance benchmarks.

810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions

1. Members of NERC and Bulk Power System owners, operators, and users shall provide NERC with detailed and timely operating experience information and data.

2. In the normal course of operations, NERC disseminates the results of its events analysis findings, lessons learned and other analysis and information gathering to the industry. These findings, lessons learned and other information will be used to guide the Reliability Assessment Program.

3. When NERC determines it is necessary to place the industry or segments of the industry on formal notice of its findings, analyses, and recommendations, NERC will provide such notification in the form of specific operations or equipment Advisories, Recommendations or Essential Actions:

   3.1 Level 1 (Advisories) – purely informational, intended to advise certain segments of the owners, operators and users of the Bulk Power System of findings and lessons learned;

   3.2 Level 2 (Recommendations) – specific actions that NERC is recommending be considered on a particular topic by certain segments of

owners, operators, and users of the Bulk Power System according to each entity's facts and circumstances;

3.3 Level 3 (Essential Actions) – specific actions that NERC has determined are essential for certain segments of owners, operators, or users of the Bulk Power System to take to ensure the reliability of the Bulk Power System. Such Essential Actions require NERC Board approval before issuance.

4. The Bulk Power System owners, operators, and users to which Level 2 (Recommendations) and Level 3 (Essential Actions) notifications apply are to evaluate and take appropriate action on such issuances by NERC. Such Bulk Power System owners, operators, and users shall also provide reports of actions taken and timely updates on progress towards resolving the issues raised in the Recommendations and Essential Actions in accordance with the reporting date(s) specified by NERC.

5. NERC will advise the Commission and other Applicable Governmental Authorities of its intent to issue all Level 1 (Advisories), Level 2 (Recommendations), and Level 3 (Essential Actions) at least five (5) business days prior to issuance, unless extraordinary circumstances exist that warrant issuance less than five (5) business days after such advice. NERC will file a report with the Commission and other Applicable Governmental Authorities no later than thirty (30) days following the date by which NERC has requested the Bulk Power System owners, operators, and users to which a Level 2 (Recommendation) or Level 3 (Essential Action) issuance applies to provide reports of actions taken in response to the notification. NERC's report to the Commission and other Applicable Governmental Authorities will describe the actions taken by the relevant owners, operators, and users of the Bulk Power System and the success of such actions taken in correcting any vulnerability or deficiency that was the subject of the notification, with appropriate protection for Confidential Information or Critical Energy Infrastructure Information.

811. Equipment Performance Data

Through its Generating Availability Data System (GADS), NERC shall collect operating information about the performance of electric generating equipment; provide assistance to those researching information on power plant outages stored in its database; and support equipment reliability as well as availability analyses and other decision-making processes developed by GADS subscribers. GADS data is also used in conducting assessments of generation resource adequacy.

SECTION 900 — TRAINING AND EDUCATION

901. Scope of the Training and Education Program

Assuring the Reliable Operation of the North American Bulk Power System requires informed knowledgeable and skilled personnel. NERC shall develop a program to oversee the coordination and delivery of learning materials, resources, and activities to allow for training and education of:

1. ERO Enterprise staff supporting statutory and delegation-related activities; and

2. Bulk Power System industry participants consistent with ERO functional program requirements.

902. Continuing Education Program

1. NERC shall develop and maintain a continuing education program to approve those activities and entities meeting NERC continuing education requirements.

2. The Personnel Subcommittee (PS), which reports to the NERC Operating Committee, is the governing body of the NERC Continuing Education Program that oversees development and implementation of the Continuing Education Program requirements.

3. The PS shall develop and update, as necessary, manual, approved by the Operating Committee, which describes the following:

    3.1 Requirements for approving contining education Providers and activities;

    3.2 Requirements for auditing continuing education Providers and activities;

    3.3 Multi-layer review process for disputed application reviews, interpretations of guideline and standards, probation or suspension of NERC-approved Provider status, and Continuing Education Hour disputes; and

    3.4 Requirements on fees for continuing education Providers and activities.

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY

1001. Situation Awareness

NERC shall through the use of Reliability Coordinators and available tools, monitor present conditions on the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary. To accomplish these goals, NERC will:

1. Maintain real-time situation awareness of conditions on the Bulk Power System;

2. Notify the industry of significant Bulk Power System events that have occurred in one area, and which have the potential to impact reliability in other areas;

3. Maintain and strengthen high-level communication, coordination, and cooperation with governments and government agencies regarding real-time conditions; and

4. Enable the Reliable Operation of interconnected Bulk Power Systems by facilitating information exchange and coordination among reliability service organizations.

1002. Reliability Support Services

NERC may assist in the development of tools and other support services for the benefit of Reliability Coordinators and other system operators to enhance reliability, operations and planning. NERC will work with the industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period, transition the tool or service to another group or owner for long term operation of the tool or provision of the service. To accomplish this goal, NERC will:

1. Collaborate with industry to determine the necessity of new tools or services to enhance reliability;

2. For those tools that the collaborative process determines should proceed to a development phase, provide a start-up mechanism and development system;

3. Implement the tool either on its own or through an appropriate group or organization; and

4. Where NERC conducts the implementation phase of a new tool or service, develop a transition plan to turn maintenance and provision of the tool or service over to an organization identified in the development stage.

In addition to tools developed as a result of a collaborative process with industry, NERC may develop reliability tools on its own, but will consult with industry concerning the need for the tool prior to proceeding to development.

Tools and services being maintained by NERC as of January 1, 2012, will be reviewed and, as warranted, transitioned to an appropriate industry group or organization. NERC will develop and maintain a strategic reliability tools plan that will list the tools and services being maintained by NERC, and, where applicable, the plans for transition to an appropriate industry group or organization.

1003. Infrastructure Security Program

NERC shall coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America by taking a leadership role in Critical Infrastructure protection of the electricity sector so as to reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure. To accomplish these goals, NERC shall perform the following functions.

1. Electric Sector Information Sharing and Analysis Center (ESISAC)

    1.1 NERC shall serve as the electricity sector's sector coordinator and operate its Information Sharing and Analysis Center to gather information and communicate security-related threats and incidents within the sector, with United States and Canadian government agencies, and with other Critical Infrastructure sectors.

    1.2 NERC shall improve the capability of the ESISAC to analyze security threats and incident information and provide situational assessments for the electricity sector and governments.

    1.3 NERC shall work closely with the United States Department of Homeland Security, Department of Energy, Natural Resources Canada, and Public Safety and Emergency Preparedness Canada.

    1.4 NERC shall strengthen and expand these functions and working relationships with the electricity sector, other Critical Infrastructure industries, governments, and government agencies throughout North America to ensure the protection of the infrastructure of the Bulk Power System.

    1.5 NERC shall fill the role of the Electricity Sector Coordinating Council and coordinate with the Government Coordinating Council.

    1.6 NERC shall coordinate with other Critical Infrastructure sectors through active participation with the other Sector Coordinating Councils, the other ISACs, and the National Infrastructure Advisory Committee.

    1.7 NERC shall encourage and participate in coordinated Critical Infrastructure protection exercises, including interdependencies with other Critical Infrastructure sectors.

2. Security Planning

2.1 NERC shall take a risk management approach to Critical Infrastructure protection, considering probability and severity, and recognizing that mitigation and recovery can be practical alternatives to prevention.

2.2 NERC shall keep abreast of the changing threat environment through collaboration with government agencies.

2.3 NERC shall develop criteria to identify critical physical and cyber assets, assess security threats, identify risk assessment methodologies, and assess effectiveness of physical and cyber protection measures.

2.4 NERC shall enhance and maintain the Bulk Power System critical spare transformer program, encourage increased participation by asset owners, and continue to assess the need to expand this program to include other critical Bulk Power System equipment.

2.5 NERC shall support implementation of the Critical Infrastructure Protection Standards through education and outreach.

2.6 NERC shall review and improve existing security guidelines, develop new security guidelines to meet the needs of the electricity sector, and consider whether any guidelines should be developed into Reliability Standards.

2.7 NERC shall conduct education and outreach initiatives to increase awareness and respond to the needs of the electricity sector.

2.8 NERC shall strengthen relationships with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.9 NERC shall maintain and improve mechanisms for the sharing of sensitive or classified information with federal, state, and provincial government agencies on Critical Infrastructure protection matters; work with DOE and DHS to implement the National Infrastructure Protection Plan, as applicable to the electricity sector; and coordinate this work with PSEPC.

2.10 NERC shall improve methods to better assess the impact of a possible physical attack on the Bulk Power System and means to deter, mitigate, and respond following an attack.

2.11 NERC shall assess the results of vulnerability assessments and enhance the security of system control and data acquisition (SCADA) and process control systems by developing methods to detect an emerging cyber attack and the means to mitigate impacts on the Bulk Power Systems.

2.12 NERC shall work with the National SCADA Test Bed and the Process Control Systems Forum to accelerate the development of technology that will enhance the security, safety, and reliability of process control and SCADA systems.

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS

1101. Scope of Business Plans and Budgets

The Board shall determine the content of the budgets to be submitted to the Applicable Governmental Authorities with consultation from the members of the Member Representatives Committee, Regional Entities, and others in accordance with the Bylaws. The Board shall identify any activities outside the scope of NERC's statutory reliability functions, if any, and the appropriate funding mechanisms for those activities.

1102. NERC Funding and Cost Allocation

1. In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on Net Energy for Load (NEL).

2. NERC's costs shall be allocated so that all Load (or, in the case of costs for an Interconnection or Regional Entity, all Load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.

3. Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.

4. Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on Net Energy for Load.

1103. NERC Budget Development

3. The NERC annual budget process shall be scheduled and conducted for each calendar year so as to allow a sufficient amount of time for NERC to receive Member inputs, develop the budget, and receive Board and, where authorized by applicable legislation or agreement, Applicable Governmental Authority approval of the NERC budget for the following fiscal year, including timely submission of the proposed budget to FERC for approval in accordance with FERC regulations.

4. The NERC budget submittal to Applicable Governmental Authorities shall include provisions for all ERO functions, all Regional Entity delegated functions as specified in delegation agreements and reasonable reserves and contingencies.

5. The NERC annual budget submittal to Applicable Governmental Authorities shall include description and explanation of NERC's proposed ERO program activities for the year; budget component justification based on statutory or other authorities; explanation of how each budgeted activity lends itself to the accomplishment of the statutory or other authorities; sufficiency of resources provided for in the budget to carry out the ERO program responsibilities;

explanation of the calculations and budget estimates; identification and explanation of changes in budget components from the previous year's budget; information on staffing and organization charts; and such other information as is required by FERC and other Applicable Governmental Authorities having authority to approve the proposed budget.

6. NERC shall develop, in consultation with the Regional Entities, a reasonable and consistent system of accounts, to allow a meaningful comparison of actual results at the NERC and Regional Entity level by the Applicable Governmental Authorities.

1104. Submittal of Regional Entity Budgets to NERC

1. Each Regional Entity shall submit its proposed annual budget for carrying out its delegated authority functions as well as all other activities and funding to NERC in accordance with a schedule developed by NERC and the Regional Entities, which shall provide for the Regional Entity to submit its final budget that has been approved by its board of directors or other governing body no later than July 1 of the prior year, in order to provide sufficient time for NERC's review and comment on the proposed budget and approval of the Regional Entity budget by the NERC Board of Trustees in time for the NERC and Regional Entity budgets to be submitted to FERC and other Applicable Governmental Authorities for approval in accordance with their regulations. The Regional Entity's budget shall include supporting materials in accordance with the budget and reporting format developed by NERC and the Regional Entities, including the Regional Entity's complete business plan and organization chart, explaining the proposed collection of all dues, fees, and charges and the proposed expenditure of funds collected in sufficient detail to justify the requested funding collection and budget expenditures.

2. NERC shall review and approve each Regional Entity's budget for meeting the requirements of its delegated authority. Concurrent with approving the NERC budget, NERC shall review and approve, or reject, each Regional Entity budget for filing.

3. NERC shall also have the right to review from time to time, in reasonable intervals but no less frequently than every three years, the financial books and records of each Regional Entity having delegated authority in order to ensure that the documentation fairly represents in all material aspects appropriate funding of delegated functions.

1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval

1. NERC shall file for approval by the Applicable Governmental Authorities at least 130 days in advance of the start of each fiscal year. The filing shall include: (1) the complete NERC and Regional Entity budgets including the business plans and organizational charts approved by the Board, (2) NERC's annual funding

requirement (including Regional Entity costs for delegated functions), and (3) the mechanism for assessing charges to recover that annual funding requirement, together with supporting materials in sufficient detail to support the requested funding requirement.

2. NERC shall seek approval from each Applicable Governmental Authority requiring such approval for the funding requirements necessary to perform ERO activities within their jurisdictions.

1106. NERC and Regional Entity Billing and Collections

1. NERC shall request the Regional Entities to identify all Load-Serving Entities[3] within each Regional Entity and the NEL assigned to each Load-Serving Entity, and the Regional Entities shall supply the requested information. The assignment of a funding requirement to an entity shall not be the basis for determining that the entity must be registered in the Compliance Registry.

2. NERC shall accumulate the NEL by Load-Serving Entities for each Applicable Governmental Authority and submit the proportional share of NERC funding requirements to each Applicable Governmental Authority for approval together with supporting materials in sufficient detail to support the requested funding requirement.

3. NEL reported by Balancing Authorities within a Region shall be used to rationalize and validate amounts allocated for collection through Regional Entity processes.

4. The billing and collection processes shall provide:

   4.1 A clear validation of billing and application of payments.

   4.2 A minimum of data requests to those being billed.

   4.3 Adequate controls to ensure integrity in the billing determinants including identification of entities responsible for funding NERC's activities.

   4.4 Consistent billing and collection terms.

5. NERC will bill and collect all budget requirements approved by Applicable Governmental Authorities (including the funds required to support those functions assigned to the Regional Entities through the delegation agreements) directly from the Load-Serving Entities or their designees or as directed by particular Applicable Governmental Authorities, except where the Regional Entity is required to collect the budget requirements for NERC, in which case the Regional

[3] A Regional Entity may allocate funding obligations using an alternative method approved by NERC and by FERC and other Applicable Governmental Authorities, as provided for in the regional delegation agreement.

Entity will collect directly from the Load-Serving Entities or as otherwise provided by agreement and submit funds to NERC. Alternatively, a load-serving entity may pay its allocated ERO costs through a Regional Entity managed collection mechanism.

6. NERC shall set a minimum threshold limit on the billing of small LSEs to minimize the administrative burden of collection.

7. NERC shall pursue any non-payments and shall request assistance from Applicable Governmental Authorities as necessary to secure collection.

8. In the case where a Regional Entity performs the collection for ERO, the Regional Entity will not be responsible for non-payment in the event that a user, owner or operator of the Bulk Power System does not pay its share of dues, fees and charges in a timely manner, provided that such a Regional Entity shall use reasonably diligent efforts to collect dues, fees, and other charges from all entities obligated to pay them. However, any revenues not paid shall be recovered from others within the same Region to avoid cross-subsidization between Regions.

9. Both NERC and the Regional Entities also may bill members or others for functions and services not within statutory requirements or otherwise authorized by the Applicable Governmental Authorities. Costs and revenues associated with these functions and services shall be separately identified and not commingled with billings associated with the funding of NERC or of the Regional Entities for delegated activities.

1107. Penalty Applications

1. Where NERC or a Regional Entity initiates a compliance monitoring and enforcement process that leads to imposition of a Penalty, the entity that initiated the process shall receive any Penalty monies imposed and collected as a result of that process, unless a different disposition of the Penalty monies is provided for in the delegation agreement, or in a contract or a disposition of the violation that is approved by NERC and FERC.

2. 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 requirements 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. Funds from financial Penalties assessed against a Canadian entity shall be applied as specified by legislation or agreement.

3. In the event that a compliance monitoring and enforcement process is conducted jointly by NERC and a Regional Entity, the Regional Entity shall receive the Penalty monies and offset the Regional Entity's budget requirements for the subsequent fiscal year.

4. Exceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by FERC or any other Applicable Governmental Authority.

1108. Special Assessments

On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next funding cycle, NERC shall file with the Applicable Governmental Authorities, where authorized by applicable legislation or agreement, for authorization for an amended or supplemental budget for NERC or a Regional Entity and, if necessary under the amended or supplemental budget, to collect a special or additional assessment for statutory functions of NERC or the Regional Entity. Such filing shall include supporting materials to justify the requested funding, including any departure from the approved funding formula or method.

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS

1201. Pro Forma Regional Delegation Agreement

NERC shall develop and maintain a pro forma Regional Entity delegation agreement, which shall serve as the basis for negotiation of consistent agreements for the delegation of ERO functions to Regional Entities.

1202. Regional Entity Essential Requirements

NERC shall establish the essential requirements for an entity to become qualified and maintain good standing as a Regional Entity.

1203. Negotiation of Regional Delegation Agreements

NERC shall, for all areas of North America that have provided NERC with the appropriate authority, negotiate regional delegation agreements for the purpose of ensuring all areas of the North American Bulk Power Systems are within a Regional Entity Region. In the event NERC is unable to reach agreement with Regional Entities for all areas, NERC shall provide alternative means and resources for implementing NERC functions within those areas. No delegation agreement shall take effect until it has been approved by the Applicable Governmental Authority.

1204. Conformance to Rules and Terms of Regional Delegation Agreements

NERC and each Regional Entity shall comply with all applicable ERO Rules of Procedure and the obligations stated in the regional delegation agreement.

1205. Sub-delegation

The Regional Entity shall not sub-delegate any responsibilities and authorities delegated to it by its regional delegation agreement with NERC except with the approval of NERC and FERC and other Applicable Governmental Authorities. Responsibilities and authorities may only be sub-delegated to another Regional Entity. Regional Entities may share resources with one another so long as such arrangements do not result in cross-subsidization or in any sub-delegation of authorities.

1206. Nonconformance to Rules or Terms of Regional Delegation Agreement

If a Regional Entity is unable to comply or is not in compliance with an ERO Rule of Procedure or the terms of the regional delegation agreement, the Regional Entity shall immediately notify NERC in writing, describing the area of nonconformance and the reason for not being able to conform to the Rule of Procedure. NERC shall evaluate each case and inform the affected Regional Entity of the results of the evaluation. If NERC determines that a Rule of Procedure or term of the regional delegation agreement has been violated by a Regional Entity or cannot practically be implemented by a Regional Entity, NERC shall notify the Applicable Governmental Authorities and take any actions necessary to address the situation.

1207. Regional Entity Audits

Approximately every five years and more frequently if necessary for cause, NERC shall audit each Regional Entity to verify that the Regional Entity continues to comply with NERC Rules of Procedure and the obligations of NERC delegation agreement. Audits of Regional Entities shall be conducted, to the extent practical, based on professional auditing standards recognized in the U.S., including Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors, and if applicable to the coverage of the audit, may be based on Canadian or other international standards. The audits required by this Section 1207 shall not duplicate the audits of Regional Entity Compliance Monitoring and Enforcement Programs provided for in **Appendix 4A**, Audit of Regional Compliance Programs, to these Rules of Procedure.

1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity

1. A Registered Entity that is registered in the Region of one Regional Entity and believes its registration should be transferred to a different Regional Entity may submit a written request to both Regional Entities requesting that they process the proposed transfer in accordance with this section. The Registered Entity's written request shall set forth the reasons the Registered Entity believes justify the proposed transfer and shall describe any impacts of the proposed transfer on other Bulk Power System owners, operators, and users.

2. After receiving the Registered Entity's written request, the two Regional Entities shall consult with each other as to whether they agree or disagree that the requested transfer is appropriate. The Regional Entities may also consult with affected Reliability Coordinators, Balancing Authorities and Transmission Operators as appropriate. Each Regional Entity shall post the request on its website for public comment period of 21 days. In evaluating the proposed transfer, the Regional Entities shall consider the location of the Registered Entity's Bulk Power System facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators; and users, the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load-Serving Entities of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity would be transitioned from the current Regional Entity to the transferee Regional Entity; along with any other reasons for the proposed transfer stated by the Registered Entity and any other reasons either Regional Entity considers relevant. The Regional Entities may request that the Registered Entity provide additional data and information concerning the proposed transfer for the Regional Entities' use in their evaluation. The Registered Entity's current Regional Entity shall notify the Registered Entity

in writing as to whether (i) the two Regional Entities agree that the requested transfer is appropriate, (ii) the two Regional Entities agree that the requested transfer is not appropriate and should not be processed further, or (iii) the two Regional Entities disagree as to whether the proposed transfer is appropriate.

3. If the two Regional Entities agree that the requested transfer is appropriate, they shall submit a joint written request to NERC requesting that the proposed transfer be approved and that the delegation agreement between NERC and each of the Regional Entities be amended accordingly. The Regional Entities' joint written submission to NERC shall describe the reasons for the proposed transfer; the location of the Registered Entity's Bulk Power System Facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators, and users; the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity will be transitioned from the current Regional Entity to the transferee Regional Entity. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

4. If the two Regional Entities do not agree with each other that the proposed transfer is appropriate, the Regional Entity supporting the proposed transfer shall, if requested by the Registered Entity, submit a written request to NERC to approve the transfer and the related delegation agreement amendments. The Regional Entity's written request shall include the information specified in Section 1208.3. The Regional Entity that does not believe the proposed transfer is appropriate will be allowed to submit a written statement to NERC explaining why the Regional Entity believes the transfer is not appropriate and should not be approved. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

5. Prior to action by the NERC Board of Trustees on a proposed transfer of registration under Section 1208.3 or 1208.4, NERC shall post information concerning the proposed transfer, including the submissions from the Regional Entities, on its website for at least twenty-one (21) days for the purpose of receiving public comment.

6. If the NERC Board of Trustees disapproves a proposed transfer presented to it pursuant to either Section 1208.3 or 1208.4, the Regional Entity or Regional Entities that believe the transfer is appropriate may, if requested to do so by the Registered Entity, file a petition with FERC pursuant to 18 C.F.R. section 39.8(f) and (g) requesting that FERC order amendments to the delegation agreements of the two Regional Entities to effectuate the proposed transfer.

7. No transfer of a Registered Entity from one Regional Entity to another Regional Entity shall be effective (i) unless approved by FERC, and (ii) any earlier than the first day of January of the second calendar year following approval by FERC, unless an earlier effective date is agreed to by both Regional Entities and NERC and approved by FERC.

SECTION 1300 — COMMITTEES

1301. Establishing Standing Committees

The Board may from time to time create standing committees. In doing so, the Board shall approve the charter of each committee and assign specific authority to each committee necessary to conduct business within that charter. Each standing committee shall work within its Board-approved charter and shall be accountable to the Board for performance of its Board-assigned responsibilities. A NERC standing committee may not delegate its assigned work to a member forum, but, in its deliberations, may request the opinions of and consider the recommendations of a member forum.

1302. Committee Membership

Each committee shall have a defined membership composition that is explained in its charter. Committee membership may be unique to each committee, and can provide for balanced decision-making by providing for representatives from each Sector or, where Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area, by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in a particular subject area. Committee membership shall also provide the opportunity for an equitable number of members from the United States and Canada, based approximately on proportionate Net Energy for Load. All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter. With regard to committees and subgroups pertaining to development of, interpretation of, or compliance with Reliability Standards, NERC shall provide a reasonable opportunity for membership from Sectors desiring to participate. Committees and subgroups organized on other than a Sector basis shall be reported to the NERC Board and the Member Representatives Committee, along with the reasons for constituting the committee or subgroup in the manner chosen. In such cases and subject to reasonable restrictions necessary to accomplish the mission of such committee or subgroup, NERC shall provide a reasonable opportunity for additional participation, as members or official observers, for Sectors not represented on the committee or subgroup.

1303. Procedures for Appointing Committee Members

Committee members shall be nominated and selected in a manner that is open, inclusive, and fair. Unless otherwise stated in these Rules of Procedure or approved by the Board, all committee member appointments shall be approved by the board, and committee officers shall be appointed by the Chairman of the Board.

1304. Procedures for Conduct of Committee Business

1. Notice to the public of the dates, places, and times of meetings of all committees, and all nonconfidential material provided to committee members, shall be posted on NERC's website at approximately the same time that notice is given to

committee members. Meetings of all standing 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 enforcement matters, litigation, or commercially sensitive or Critical Energy Infrastructure Information of any entity.

2. NERC shall maintain a set of procedures, approved by the Board, to guide the conduct of business by standing committees.

1305. Committee Subgroups

Standing committees may appoint subgroups using the same principles as in Section 1302.

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE

1401. Proposals for Amendment or Repeal of Rules of Procedure

In accordance with the Bylaws of NERC, requests to amend or repeal the Rules of Procedure may be submitted by (1) any fifty Members of NERC, which number shall include Members from at least three membership Sectors, (2) the Member Representatives Committee, (3) a committee of NERC to whose function and purpose the Rule of Procedure pertains, or (4) an officer of NERC.

1402. Approval of Amendment or Repeal of Rules of Procedure

Amendment to or repeal of Rules of Procedure shall be approved by the Board after public notice and opportunity for comment in accordance with the Bylaws of NERC. In approving changes to the Rules of Procedure, the Board shall consider the inputs of the Member Representatives Committee, other ERO committees affected by the particular changes to the Rules of Procedure, and other stakeholders as appropriate. After Board approval, the amendment or repeal shall be submitted to the Applicable Governmental Authorities for approval, where authorized by legislation or agreement. No amendment to or repeal of the Rules of Procedure shall be effective until it has been approved by the Applicable Governmental Authorities.

SECTION 1500 — CONFIDENTIAL INFORMATION

1501. Definitions

1. **Confidential Information** means (i) Confidential Business and Market Information; (ii) Critical Energy Infrastructure Information; (iii) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (iv) work papers, including any records produced for or created in the course of an evaluation or audit; (v) investigative files, including any records produced for or created in the course of an investigation; or (vi) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition.

2. **Confidential Business and Market Information** means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

3. **Critical Energy Infrastructure Information** means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.

4. **Critical Infrastructure** means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

5. **Cyber Security Incident Information** means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

1502. Protection of Confidential Information

1. **Identification of Confidential Information** — An owner, operator, or user of the Bulk Power System and any other party (the "Submitting Entity") shall mark as confidential any information that it submits to NERC or a Regional Entity (the "Receiving Entity") that it reasonably believes contains Confidential Information as defined by these Rules of Procedure, indicating the category or categories defined in Section 1501 in which the information falls. If the information is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the Submitting Entity shall so indicate and provide supporting references and details.

2. **Confidentiality** — Except as provided herein, a Receiving Entity shall keep in confidence and not copy, disclose, or distribute any Confidential Information or

any part thereof without the permission of the Submitting Entity, except as otherwise legally required.

3. **Information no longer Confidential –** If a Submitting Entity concludes that information for which it had sought confidential treatment no longer qualifies for that treatment, the Submitting Entity shall promptly so notify NERC or the relevant Regional Entity.

1503. Requests for Information

1. **Limitation** — A Receiving Entity shall make information available only to one with a demonstrated need for access to the information from the Receiving Entity.

2. **Form of Request** — A person with such a need may request access to information by using the following procedure:

   2.1 The request must be in writing and clearly marked "Request for Information."

   2.2 The request must identify the individual or entity that will use the information, explain the requester's need for access to the information, explain how the requester will use the information in furtherance of that need, and state whether the information is publicly available or available from another source or through another means. If the requester seeks access to information that is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the requester shall describe how it qualifies to receive such information.

   2.3 The request must stipulate that, if the requester does not seek public disclosure, the requester will maintain as confidential any information received for which a Submitting Party has made a claim of confidentiality in accordance with NERC's rules. As a condition to gaining access to such information, a requester shall execute a non-disclosure agreement in a form approved by NERC's Board of Trustees.

3. **Notice and Opportunity for Comment** — Prior to any decision to disclose information marked as confidential, the Receiving Entity shall provide written notice to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed. Failure to provide such comments or otherwise respond is not deemed waiver of the claim of confidentiality.

4. **Determination by ERO or Regional Entity** — Based on the information provided by the requester under Rule 1503.2, any comments provided by the Submitting Entity, and any other relevant available information, the chief

executive officer or his or her designee of the Receiving Entity shall determine whether to disclose such information.

5. **Appeal** — A person whose request for information is denied in whole or part may appeal that determination to the President of NERC (or the President's designee) within 30 days of the determination. Appeals filed pursuant to this Section must be in writing, addressed to the President of NERC (or the President's designee), and clearly marked "Appeal of Information Request Denial."

   NERC will provide written notice of such appeal to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed; provided that any such comments must be received within 30 days of the notice and any failure to provide such comments or otherwise respond is not deemed a waiver of the claim of confidentiality.

   The President of NERC (or the President's designee) will make a determination with respect to any appeal within 30 days. In unusual circumstances, this time limit may be extended by the President of NERC (or the President's designee), who will send written notice to the requester setting forth the reasons for the extension and the date on which a determination on the appeal is expected.

6. **Disclosure of Information** — In the event the Receiving Entity, after following the procedures herein, determines to disclose information designated as Confidential Information, it shall provide the Submitting Entity no fewer than 21 days' written notice prior to releasing the Confidential Information in order to enable such Submitting Entity to (a) seek an appropriate protective order or other remedy, (b) consult with the Receiving Entity with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. Should a Receiving Entity be required to disclose Confidential Information, or should the Submitting Entity waive objection to disclosure, the Receiving Entity shall furnish only that portion of the Confidential Information which the Receiving Entity's counsel advises is legally required.

7. **Posting of Determinations on Requests for Disclosure of Confidential Information** — Upon making its determination on a request for disclosure of Confidential Information, NERC or the Regional Entity, as applicable, shall (i) notify the requester that the request for disclosure is granted or denied, (ii) publicly post any determination to deny the request to disclose Confidential Information, including in such posting an explanation of the reasons for the denial (but without in such explanation disclosing the Confidential Information), and (iii) publicly post any determination that information claimed by the Submitting Entity to be Confidential Information is not Confidential Information (but without in such posting disclosing any information that has been determined to be Confidential Information).

1504. Employees, Contractors and Agents

A Receiving Entity shall ensure that its officers, trustees, directors, employees, subcontractors and subcontractors' employees, and agents to whom Confidential Information is exposed are under obligations of confidentiality that are at least as restrictive as those contained herein.

1505. Provision of Information to FERC and Other Governmental Authorities

1. **Request** — A request from FERC for reliability information with respect to owners, operators, and users of the Bulk Power System within the United States is authorized by Section 215 of the Federal Power Act. Other Applicable Governmental Authorities may have similar authorizing legislation that grants a right of access to such information. Unless otherwise directed by FERC or its staff or the other Applicable Governmental Authority requesting the information, upon receiving such a request, a Receiving Entity shall provide contemporaneous notice to the applicable Submitting Entity. In its response to such a request, a Receiving Entity shall preserve any mark of confidentiality and shall notify FERC or other Applicable Governmental Authorities that the Submitting Entity has marked the information as confidential.

2. **Continued Confidentiality** — Each Receiving Entity shall continue to treat as confidential all Confidential Information that it has submitted to NERC or to FERC or another Applicable Governmental Authority, until such time as FERC or the other Applicable Governmental Authority authorizes disclosure of such information.

1506. Permitted Disclosures

1. **Confirmed Violations** — Nothing in this Section 1500 shall prohibit the disclosure of a violation at the point when the matter is filed with an Applicable Governmental Authority as a Notice of Penalty, the "violator" admits to the violation, or the alleged violator and NERC or the Regional Entity reach a settlement regarding the violation.

2. **Compliance Information** — NERC and the Regional Entities are authorized to exchange Confidential Information related to evaluations, Compliance Audits, and Compliance Investigations in furtherance of the Compliance Monitoring and Enforcement Program, on condition they continue to maintain the confidentiality of such information.

1507. Remedies for Improper Disclosure

Any person engaged in NERC or Regional Entity activity under Section 215 of the Federal Power Act or the equivalent laws of other Applicable Governmental Authorities who improperly discloses information determined to be confidential may lose access to Confidential Information on a temporary or permanent basis and may be subject to adverse personnel action, including suspension or termination. Nothing in Section 1500

precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION

1601. Scope of a NERC or Regional Entity Request for Data or Information

Within the United States, NERC and Regional Entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d). In other jurisdictions NERC and Regional Entities may request comparable data or information, using such authority as may exist pursuant to these Rules of Procedure and as may be granted by Applicable Governmental Authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information; the Requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.

1602. Procedure for Authorizing a NERC Request for Data or Information

1. NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified in Section 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with Section 1602.2 or issuing the request or modification to Reporting Entities following approval by the Board of Trustees.

2. NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.

    2.1. A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information ("Reporting Entities"); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., "Confidential Information," "Critical Energy Infrastructure Information," "aggregating"

or "identity masking"); and (vi) an estimate of the relative burden imposed on the Reporting Entities to accommodate the data or information request.

2.2. A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the Reporting Entities to accommodate the modified data or information request, and (iii) any other items from Section 1602.2.1 that require updating as a result of the modifications.

3. After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC's evaluation of the comments and recommendations, to the Board of Trustees.

4. In acting on the proposed request for data or information, the Board of Trustees may authorize NERC to issue it, modify it, or remand it for further consideration.

5. NERC may make minor changes to an authorized request for data or information without Board approval. However, if a Reporting Entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require Board approval before they are implemented.

6. Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board of Trustees, an affected party appeals the authorization under this Section 1600 to the Applicable Governmental Authority.

1603. Owners, Operators, and Users to Comply

Owners, operators, and users of the Bulk Power System registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a Reporting Entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the Reporting Entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.

1604. Requests by Regional Entity for Data or Information

1. A Regional Entity may request that NERC seek authorization for a request for data or information to be applicable within the Region of the Regional Entity, either as a freestanding request or as part of a proposed NERC request for data or information. Any such request must be consistent with this Section 1600.

2. A Regional Entity may also develop its own procedures for requesting data or information, but any such procedures must include at least the same procedural

elements as are included in this Section 1600. Any such Regional Entity procedures or changes to such procedures shall be submitted to NERC for approval. Upon approving such procedures or changes thereto, NERC shall file the proposed procedures or proposed changes for approval by the Commission and any other Applicable Governmental Authorities applicable to the Regional Entity. The Regional Entity procedures or changes to such procedures shall not be effective in a jurisdiction until approved by, and in accordance with any revisions directed by, the Commission or other Applicable Governmental Authority.

1605. Confidentiality

If the approved data or information request includes a statement under Section 1602.1.1(v) that the requested data or information will be held confidential or treated as Critical Energy Infrastructure Information, then the applicable provisions of Section 1500 will apply without further action by a Submitting Entity. A Submitting Entity may designate any other data or information as Confidential Information pursuant to the provisions of Section 1500, and NERC or the Regional Entity shall treat that data or information in accordance with Section 1500. NERC or a Regional Entity may utilize additional protective procedures for handling particular requests for data or information as may be necessary under the circumstances.

1606. Expedited Procedures for Requesting Time-Sensitive Data or Information

1. In the event NERC or a Regional Entity must obtain data or information by a date or within a time period that does not permit adherence to the time periods specified in Section 1602, the procedures specified in Section 1606 may be used to obtain the data or information. Without limiting the circumstances in which the procedures in Section 1606 may be used, such circumstances include situations in which it is necessary to obtain the data or information (in order to evaluate a threat to the reliability or security of the Bulk Power System, or to comply with a directive in an order issued by the Commission or by another Applicable Governmental Authority) within a shorter time period than possible under Section 1602. The procedures specified in Section 1606 may only be used if authorized by the NERC Board of Trustees prior to activation of such procedures.

2. Prior to posting a proposed request for data or information, or a modification to a previously-authorized request, for public comment under Section 1606, NERC shall provide the proposed request or modification, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability. The submission to the Commission's Office of Electric Reliability shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information. The submission shall be made to the Commission's Office of Electric Reliability as far in advance, up to twenty-one (21) days, of the posting of the proposed request or modification for public comments as is reasonably possible under the circumstances, but in no event less than two (2) days in advance of the public posting of the proposed request or modification.

3. NERC shall post the proposed request for data or information or proposed modification to a previously-authorized request for data or information for a public comment period that is reasonable in duration given the circumstances, but in no event shorter than five (5) days. The proposed request for data or information or proposed modification to a previously-authorized request for data or information shall include the information specified in Section 1602.2.1 or 1602.2.2, as applicable, and shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information.

4. The provisions of Sections 1602.3, 1602.4, 1602.5 and 1602.6 shall be applicable to a request for data or information or modification to a previously-authorized request for data or information developed and issued pursuant to Section 1606, except that (a) if NERC makes minor changes to an authorized request for data or information without Board approval, such changes shall require Board approval if a Reporting Entity objects to NERC in writing to such changes within five (5) days of issuance of the modified request; and (b) authorization of the request for data or information shall be final unless an affected party appeals the authorization of the request by the Board of Trustees to the Applicable Governmental Authority within five (5) days following the decision of the Board of Trustees authorizing the request, which decision shall be promptly posted on NERC's website.

SECTION 1700 — CHALLENGES TO DETERMINATIONS

1701. Scope of Authority

Section 1702 sets forth the procedures to be followed for Registered Entities to challenge determinations made by Planning Coordinators under Reliability Standard PRC-023. Section 1703 sets forth the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023

1. This Section 1702 establishes the procedures to be followed when a Registered Entity wishes to challenge a determination by a Planning Coordinator of the sub-200 kV circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers (defined as "Registered Entities" for purposes of this Section 1702) must comply with the requirements of Reliability Standard PRC-023.

2. Planning Coordinator Procedures

    2.1 Each Planning Coordinator shall establish a procedure for a Registered Entity to submit a written request for an explanation of a determination made by the Planning Coordinator under PRC-023.

    2.2 A Registered Entity shall follow the procedure established by the Planning Coordinator for submitting the request for explanation and must submit any such request within 60 days of receiving the determination under PRC-023 from the Planning Coordinator.

    2.3 Within 30 days of receiving a written request from a Registered Entity, the Planning Coordinator shall provide the Registered Entity with a written explanation of the basis for its determination under PRC-023, unless the Planning Coordinator provided a written explanation of the basis for its determination when it initially informed the Registered Entity of its determination.

3. A Registered Entity may challenge the determination of the Planning Coordinator by filing with the appropriate Regional Entity, with a copy to the Planning Coordinator, within 60 days of receiving the written explanation from the Planning Coordinator. The challenge shall include the following: (a) an explanation of the technical reasons for its disagreement with the Planning Coordinator's determination, along with any supporting documentation, and (b) a copy of the Planning Coordinator's written explanation. Within 30 days of receipt of a challenge, the Planning Coordinator may file a response to the Regional Entity, with a copy to the Registered Entity.

4. The filing of a challenge in good faith shall toll the time period for compliance with PRC-023 with respect to the subject facility until such time as the challenge is withdrawn, settled or resolved.

5. The Regional Entity shall issue its written decision setting forth the basis of its determination within 90 days after it receives the challenge and send copies of the decision to the Registered Entity and the Planning Coordinator. The Regional Entity may convene a meeting of the involved entities and may request additional information. The Regional Entity shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

6. A Planning Coordinator or Registered Entity affected by the decision of the Regional Entity may, within 30 days of the decision, file an appeal with NERC, with copies to the Regional Entity and the Planning Coordinator or Registered Entity. The appeal shall state the basis of the objection to the decision of the Regional Entity and shall include the Regional Entity decision, the written explanation of the Planning Coordinator's determination under PRC-023, and the documents and reasoning filed by the Registered Entity with the Regional Entity in support of its objection. The Regional Entity, Planning Coordinator or Registered Entity may file a response to the appeal within 30 days of the appeal.

7. The Board of Trustees shall appoint a panel to decide appeals from Regional Entity decisions under Section 1702.5. The panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about PRC-023 and transmission planning and do not have a direct financial or business interest in the outcome of the appeal. The panel shall decide the appeal within 90 days of receiving the appeal from the decision of the Regional Entity and shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

8. The Planning Coordinator or Registered Entity affected by the decision of the panel may request that the Board of Trustees review the decision by filing its request for review and a statement of reasons with NERC's Chief Reliability Officer within 30 days of the panel decision. The Board of Trustees may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. Within 90 days of the request for review under this Section 1702.8, the Board of Trustees may either (a) issue a decision on the merits, which shall be the final NERC decision, or (b) issue a notice declining to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. If no written decision or notice declining review is issued within 90 calendar days, the appeal shall be deemed to have been denied by the Board of Trustees and this will have the same effect as a notice declining review.

9. The Registered Entity or Planning Coordinator may appeal the final NERC decision to the Applicable Governmental Authority within 30 days of receipt of

the Board of Trustees' final decision or notice declining review, or expiration of the 90-day review period without any action by NERC.

10. The Planning Coordinator and Registered Entity are encouraged, but not required, to meet to resolve any dispute, including use of mutually agreed to alternative dispute resolution procedures, at any time during the course of the matter. In the event resolution occurs after the filing of a challenge, the Registered Entity and Planning Coordinator shall jointly provide to the applicable Regional Entity a written acknowledgement of withdrawal of the challenge or appeal, including a statement that all outstanding issues have been resolved.

1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509

1. This Section 1703 establishes the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

2. A Submitting Entity (or Owner if different) aggrieved by the decision of NERC to approve or disapprove an Exception Request or to terminate an Exception with respect to any Element may, within 30 days following the date of the decision, file a written challenge to the decision with the NERC director of compliance operations, with copies to the Regional Entity and the Submitting Entity or Owner if different. The challenge shall state the basis of the objection to the decision of NERC. The Regional Entity, and the Submitting Entity or Owner if different, may file a response to the challenge within 30 days following the date the challenge is filed with NERC.

3. The challenge shall be decided by the Board of Trustees Compliance Committee. Within 90 days of the date of submission of the challenge, the Board of Trustees Compliance Committee shall issue its decision on the challenge. The decision of the Board of Trustees Compliance Committee shall be the final NERC decision; provided, that the Board of Trustees Compliance Committee may extend the deadline date for its decision to a date more than 90 days following submission of the challenge, by issuing a notice to the Submitting Entity, the Owner (if different) and the Regional Entity stating the revised deadline date and the reason for the extension.

4. The Submitting Entity, or Owner if different, may appeal the final NERC decision to, or seek review of the final NERC decision by, the Applicable Governmental Authority(ies), in accordance with the legal authority and rules and procedures of the Applicable Governmental Authority(ies). Any such appeal shall be filed within thirty (30) days following the date of the decision of the Board of Trustees Compliance Committee, or within such other time period as is provided for in the legal authority, rules or procedures of the Applicable Governmental Authority.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rules of Procedure

Effective: ~~October 31, 2016~~[proposed date]

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SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE

NERC and NERC Members shall comply with these Rules of Procedure. Each Regional Entity shall comply with these Rules of Procedure as applicable to functions delegated to the Regional Entity by NERC or as required by an Applicable Governmental Authority or as otherwise provided.

Each Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities by approval pursuant to applicable legislation or regulation, or pursuant to agreement.

Any entity that is unable to comply or that is not in compliance with a NERC Rule of Procedure shall immediately notify NERC in writing, stating the Rule of Procedure of concern and the reason for not being able to comply with the Rule of Procedure.

NERC shall evaluate each case and inform the entity of the results of the evaluation. If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify the Applicable Governmental Authorities and take such other actions as NERC deems appropriate to address the situation.

NERC shall comply with each approved Reliability Standard that identifies NERC or the Electric Reliability Organization as a responsible entity. Regional Entities shall comply with each approved Reliability Standard that identifies Regional Entities as responsible entities. A violation by NERC or a Regional Entity of such a Reliability Standard shall constitute a violation of these Rules of Procedure.

SECTION 200 — DEFINITIONS OF TERMS

Definitions of terms used in the NERC Rules of Procedure are set forth in **Appendix 2**, *Definitions Used in the Rules of Procedure*.

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT

301. General

NERC shall develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable NERC and Regional Entities to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems. The Reliability Standards shall be technically excellent, timely, just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with other applicable standards of governmental authorities.

302. Essential Attributes for Technically Excellent Reliability Standards

1. **Applicability** — Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the Reliability Standard, with any specific additions or exceptions noted. Such functional classes[1] include: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, market operators, Planning Authorities, Transmission Planners, Resource Planners, and Distribution Providers. Each Reliability Standard shall also identify the geographic applicability of the Reliability Standard, such as the entire North American Bulk Power System, an Interconnection, or within a Region. A Reliability Standard may also identify any limitations on the applicability of the Reliability Standard based on electric Facility characteristics.

2. **Reliability Objectives** — Each Reliability Standard shall have a clear statement of purpose that shall describe how the Reliability Standard contributes to the reliability of the Bulk Power System. The following general objectives for the Bulk Power System provide a foundation for determining the specific objective(s) of each Reliability Standard:

    2.1 **Reliability Planning and Operating Performance** — Bulk Power Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.

    2.2 **Frequency and Voltage Performance** — The frequency and voltage of Bulk Power Systems shall be controlled within defined limits through the balancing of Real and Reactive Power supply and demand.

[1] These functional classes of entities are derived from NERC's Reliability Functional Model. When a Reliability Standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in NERC Reliability Standards.

2.3 **Reliability Information** — Information necessary for the planning and operation of reliable Bulk Power Systems shall be made available to those entities responsible for planning and operating Bulk Power Systems.

2.4 **Emergency Preparation** — Plans for emergency operation and system restoration of Bulk Power Systems shall be developed, coordinated, maintained, and implemented.

2.5 **Communications and Control** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of Bulk Power Systems.

2.6 **Personnel** — Personnel responsible for planning and operating Bulk Power Systems shall be trained and qualified, and shall have the responsibility and authority to implement actions.

2.7 **Wide-Area View** — The reliability of the Bulk Power Systems shall be assessed, monitored, and maintained on a Wide-Area basis.

2.8 **Security** — Bulk Power Systems shall be protected from malicious physical or cyber attacks.

3. **Performance Requirement or Outcome** — Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Power System, consistent with good utility practices and the public interest. Each Requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for Bulk Power System reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance Requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that Requirement. Each performance Requirement shall have one or more associated measures used to objectively evaluate compliance with the Requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations** — Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness** — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for Penalties and sanctions, as well as other ERO and Regional Entity compliance

documents, the consequences of violating a Reliability Standard are clearly presented to the entities responsible for complying with the Reliability Standards.

8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.

9. **Practicality** — Each Reliability Standard shall establish Requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology** — To the extent possible, Reliability Standards shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards development process.

303. Relationship between Reliability Standards and Competition

To ensure Reliability Standards are developed with due consideration of impacts on competition, to ensure Reliability Standards are not unduly discriminatory or preferential, and recognizing that reliability is an essential requirement of a robust North American economy, each Reliability Standard shall meet all of these market-related objectives:

1. **Competition** — A Reliability Standard shall not give any market participant an unfair competitive advantage.

2. **Market Structures** — A Reliability Standard shall neither mandate nor prohibit any specific market structure.

3. **Market Solutions** — A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.

4. **Commercially Sensitive Information** — A Reliability Standard shall not require the public disclosure of commercially sensitive information or other Confidential Information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.

5. **Adequacy** — NERC shall not set Reliability Standards defining an adequate amount of, or requiring expansion of, Bulk Power System resources or delivery capability.

304. Essential Principles for the Development of Reliability Standards

NERC shall develop Reliability Standards in accordance with the NERC *Standard Processes Manual*, which is incorporated into these Rules of Procedure as **Appendix 3A**. Appeals in connection with the development of a Reliability Standard shall also be conducted in accordance with the NERC *Standard Processes Manual*. Any amendments

or revisions to the *Standard Processes Manual* shall be consistent with the following essential principles:

1. **Openness** — Participation shall be open to all Persons and who are directly and materially affected by the reliability of the North American Bulk Power System. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

2. **Transparency** — The process shall be transparent to the public.

3. **Consensus-building** —The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any two Segments as defined in **Appendix 3D**, *Development of the Registered Ballot Body*, of these Rules of Procedure, and no single Segment, individual or organization shall be able to defeat a matter.

5. **Due Process** — Development of Reliability Standards shall provide reasonable notice and opportunity for any Person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.

6. **Timeliness** — Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

305. Registered Ballot Body

NERC Reliability Standards shall be approved by a Registered Ballot Body prior to submittal to the Board and then to Applicable Governmental Authorities for their approval, where authorized by applicable legislation or agreement. This Section 305 sets forth the rules pertaining to the composition of, and eligibility to participate in, the Registered Ballot Body.

1. **Eligibility to Vote on Reliability Standards** — Any person or entity may join the Registered Ballot Body to vote on Reliability Standards, whether or not such person or entity is a Member of NERC.

2. **Inclusive Participation** — The Segment qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the reliability of the Bulk Power System that can meet any one of the eligibility criteria for a Segment is entitled to

belong to and vote in each Segment for which it qualifies, subject to limitations defined in Sections 305.3 and 305.5.

3. **General Criteria for Registered Ballot Body Membership** — The general criteria for membership in the Segments are:

   3.1 **Multiple Segments** — A corporation or other organization with integrated operations or with affiliates that qualifies to belong to more than one Segment (e.g., Transmission Owners and Load-Serving Entities) may join once in each Segment for which it qualifies, provided that each Segment constitutes a separate membership and the organization is represented in each Segment by a different representative. Affiliated entities are collectively limited to one membership in each Segment for which they are qualified.

   3.2 **Withdrawing from a Segment or Changing Segments** — After its initial registration in a Segment, each registered participant may elect to withdraw from a Segment or apply to change Segments at any time.

   3.3 **Review of Segment Criteria** — The Board shall review the qualification guidelines and rules for joining Segments at least every three years to ensure that the process continues to be fair, open, balanced, and inclusive. Public input will be solicited in the review of these guidelines.

4. **Proxies for Voting on Reliability Standards** — Any registered participant may designate an agent or proxy to vote on its behalf. There are no limits on how many proxies an agent may hold. However, for the proxy to be valid, NERC must have in its possession written documentation signed by the representative of the registered participant that the voting right by proxy has been transferred from the registered participant to the agent.

5. **Segments** — The specific criteria for membership in each Registered Ballot Body Segment are defined in the *Development of the Registered Ballot Body* in **Appendix 3D.**

6. **Review of Segment Entries** — NERC shall review all applications for joining the Registered Ballot Body, and shall make a determination of whether the applicant's self-selection of a Segment satisfies at least one of the guidelines to belong to that Segment. The entity shall then become eligible to participate as a voting member of that Segment. The Standards Committee shall resolve disputes regarding eligibility for membership in a Segment, with the applicant having the right of appeal to the Board.

306. Standards Committee

The Standards Committee shall provide oversight of the Reliability Standards development process to ensure stakeholder interests are fairly represented. The Standards Committee shall not under any circumstance change the substance of a draft or approved Reliability Standard.

1. **Membership** — The Standards Committee is a representative committee comprising representatives of two members of each of the Segments in the Registered Ballot Body and two officers elected to represent the interests of the industry as a whole.

2. **Elections** — Standards Committee members are elected for staggered (one per Segment per year) two-year terms by the respective Segments in accordance with the *Procedure for the Election of Members of the NERC Standards Committee*, which is incorporated into these Rules of Procedure as **Appendix 3B**. Segments may use their own election procedure if such a procedure is ratified by two-thirds of the members of a Segment and approved by the Board.

3. **Canadian Representation**

   The Standards Committee will include Canadian representation as provided in **Appendix 3B**, *Procedure for the Election of Members of the NERC Standards Committee*.

4. **Open Meetings** — All meetings of the Standards Committee shall be open and publicly noticed on the NERC website.

307. Standards Process Management

NERC shall assign a standards process manager to administer the development of continent-wide Reliability Standards and a regional standards manager to administer the development of Regional Reliability Standards. The standards process manager shall be responsible for ensuring that the development and revision of Reliability Standards are in accordance with the NERC *Standard Processes Manual*. The standards process manager and the regional standards manager shall work to achieve the highest degree of integrity and consistency of quality and completeness of the Reliability Standards. The regional standards manager shall coordinate with any Regional Entities that develop Regional Reliability Standards to ensure those Regional Reliability Standards are effectively integrated with the NERC Reliability Standards.

308. Steps in the Development of Reliability Standards

1. **Procedure** — NERC shall develop Reliability Standards through the process set forth in the NERC *Standard Processes Manual* (**Appendix 3A**). The *Standard Processes Manual* includes provisions for developing Reliability Standards that can be completed using expedited processes, including a process to develop Reliability Standards to address national security situations that involve confidential issues.

2. **Board Adoption** — Reliability Standards or revisions to Reliability Standards approved by the ballot pool in accordance with the *Standard Processes Manual* shall be submitted for adoption by the Board. No Reliability Standard or revision to a Reliability Standard shall be effective unless adopted by the Board.

3. **Governmental Approval** — After Board adoption, a Reliability Standard or revision to a Reliability Standard shall be submitted to all Applicable Governmental Authorities in accordance with Section 309. No Reliability Standard or revision to a Reliability Standard shall be effective within a geographic area over which an Applicable Governmental Authority has jurisdiction unless it is approved by such Applicable Governmental Authority or is otherwise made effective pursuant to the laws applicable to such Applicable Governmental Authority.

309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities

1. **Filing of Reliability Standards for Approval** — Where authorized by applicable legislation or agreement, NERC shall file with the Applicable Governmental Authorities each Reliability Standard, modification to a Reliability Standard, or withdrawal of a Reliability Standard that is adopted by the Board. Each filing shall be in the format required by the Applicable Governmental Authority and shall include: a concise statement of the basis and purpose of the Reliability Standard; the text of the Reliability Standard; the implementation plan for the Reliability Standard; a demonstration that the Reliability Standard meets the essential attributes of Reliability Standards as stated in Section 302; the drafting team roster; the ballot pool and final ballot results; and a discussion of public comments received during the development of the Reliability Standard and the consideration of those comments.

2. **Remanded Reliability Standards and Directives to Develop Standards** — If an Applicable Governmental Authority remands a Reliability Standard to NERC or directs NERC to develop a Reliability Standard, NERC shall within five (5) business days notify all other Applicable Governmental Authorities, and shall within thirty (30) calendar days report to all Applicable Governmental Authorities a plan and timetable for modification or development of the Reliability Standard. Reliability Standards that are remanded or directed by an Applicable Governmental Authority shall be modified or developed using the *Standard Processes Manual*. NERC shall, during the development of a modification for the remanded Reliability Standard or directed Reliability Standard, consult with other Applicable Governmental Authorities to coordinate any impacts of the proposed Reliability Standards in those other jurisdictions. The expedited standards development process may be applied if necessary to meet a timetable for action required by the Applicable Governmental Authorities, respecting to the extent possible the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of

Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply.

3. **Directives to Develop Reliability Standards under Extraordinary Circumstances** — An Applicable Governmental Authority may, on its own initiative, determine that extraordinary circumstances exist requiring expedited development of a Reliability Standard. In such a case, the Applicable Governmental Authority may direct the development of a Reliability Standard within a certain deadline. NERC staff shall prepare the Standards Authorization Request. The proposed Reliability Standard will then proceed through the Reliability Standards development process, using the expedited action process described in the *Standard Processes Manual* as necessary to meet the specified deadline. The timeline will be developed to respect, to the extent possible, the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply, with appropriate modification of the timeline.

310. Annual Reliability Standards Development Plan

NERC shall develop and provide an annual Reliability Standards Development Plan for development of Reliability Standards to the Applicable Governmental Authorities. NERC shall consider the comments and priorities of the Applicable Governmental Authorities in developing and updating the annual Reliability Standards Development Plan. Each annual Reliability Standards Development Plan shall include a progress report comparing results achieved to the prior year's Reliability Standards Development Plan.

311. Regional Entity Standards Development Procedures

1. **NERC Approval of Regional Entity Reliability Standards Development Procedure** — To enable a Regional Entity to develop Regional Reliability Standards that are to be recognized and made part of NERC Reliability Standards, a Regional Entity may request NERC to approve a Regional Reliability Standards development procedure.

2. **Public Notice and Comment on Regional Reliability Standards Development Procedure** — Upon receipt of such a request, NERC shall publicly notice and request comment on the proposed Regional Reliability Standards development procedure, allowing a minimum of 45 days for comment. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to withdraw the request, revise the Regional Reliability Standards development procedure and request another posting for comment, or submit the

Regional Reliability Standards development procedure, along with its consideration of any objections received, for approval by NERC.

3. **Evaluation of Regional Reliability Standards Development Procedure** — NERC shall evaluate whether a Regional Reliability Standards development procedure meets the criteria listed below and shall consider stakeholder comments, any unresolved stakeholder objections, and the consideration of comments provided by the Regional Entity, in making that determination. If NERC determines the Regional Reliability Standards development procedure meets these requirements, the Regional Reliability Standards development procedure shall be submitted to the Board for approval. The Board shall consider the recommended action, stakeholder comments, any unresolved stakeholder comments, and the Regional Entity consideration of comments in determining whether to approve the Regional Reliability Standards development procedure.

3.1 **Evaluation Criteria** — The Regional Reliability Standards development procedure shall be:

3.1.1 **Open** — The Regional Reliability Standards development procedure shall provide that any person or entity who is directly and materially affected by the reliability of the Bulk Power Systems within the Regional Entity shall be able to participate in the development and approval of Reliability Standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the Regional Entity, a Regional Entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

3.1.2 **Inclusive** — The Regional Reliability Standards development procedure shall provide that any Person with a direct and material interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process if adversely affected.

3.1.3 **Balanced** — The Regional Reliability Standards development procedure shall have a balance of interests and shall not permit any two interest categories to dominate a matter or any single interest category to defeat a matter.

3.1.4 **Due Process** — The Regional Reliability Standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the Regional Reliability Standards development procedure shall include public notice of the intent to develop a Regional Reliability Standard, a public comment period on the proposed Regional Reliability Standard,

due consideration of those public comments, and a ballot of interested stakeholders.

3.1.5 **Transparent** — All actions material to the development of Regional Reliability Standards shall be transparent. All Regional Reliability Standards development meetings shall be open and publicly noticed on the Regional Entity's website.

3.1.6 **Accreditation of Regional Standards Development Procedure** — A Regional Entity's Regional Reliability Standards development procedure that is accredited by the American National Standards Institute shall be deemed to meet the criteria listed in this Section 311.3.1, although such accreditation is not a prerequisite for approval by NERC.

3.1.7 **Use of NERC Procedure** — A Regional Entity may adopt the NERC *Standard Processes Manual* as the Regional Reliability Standards development procedure, in which case the Regional Entity's Regional Reliability Standards development procedure shall be deemed to meet the criteria listed in this Section 311.3.1.

4. **Revisions of Regional Reliability Standards Development Procedures** — Any revision to a Regional Reliability Standards development procedure shall be subject to the same approval requirements set forth in Sections 311.1 through 311.3.

5. **Duration of Regional Reliability Standards Development Procedures** — The Regional Reliability Standards development procedure shall remain in effect until such time as it is replaced with a new version approved by NERC or it is withdrawn by the Regional Entity. The Regional Entity may, at its discretion, withdraw its Regional Reliability Standards development procedure at any time.

312. Regional Reliability Standards

1. **Basis for Regional Reliability Standards** — Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard. Such Regional Reliability Standards shall in all cases be submitted to NERC for adoption and, if adopted, made part of the NERC Reliability Standards and shall be enforceable in accordance with the delegation agreement between NERC and the Regional Entity or other instrument granting authority over enforcement to the Regional Entity. No entities other than NERC and the Regional Entity shall be permitted to develop Regional Reliability Standards that are enforceable under statutory authority delegated to NERC and the Regional Entity.

2. **Regional Reliability Standards That are Directed by a NERC Reliability Standard** — Although it is the intent of NERC to promote uniform Reliability

Standards across North America, in some cases it may not be feasible to achieve a reliability objective with a Reliability Standard that is uniformly applicable across North America. In such cases, NERC may direct Regional Entities to develop Regional Reliability Standards necessary to implement a NERC Reliability Standard. Such Regional Reliability Standards that are developed pursuant to a direction by NERC shall be made part of the NERC Reliability Standards.

3. **Procedure for Developing an Interconnection-wide Regional Standard** — A Regional Entity organized on an Interconnection-wide basis may propose a Regional Reliability Standard for approval as a NERC Reliability Standard to be made mandatory for all applicable Bulk Power System owners, operators, and users within that Interconnection.

3.1 **Presumption of Validity** — An Interconnection-wide Regional Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities, shall be adopted as a NERC Reliability Standard. NERC shall rebuttably presume that a Regional Reliability Standard developed, in accordance with a Regional Reliability Standards development process approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities.

3.2 **Notice and Comment Procedure for Interconnection-wide Regional Reliability Standard** — NERC shall publicly notice and request comment on the proposed Interconnection-wide Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to comment on or withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for approval by NERC.

3.3 **Adoption of Interconnection-wide Regional Reliability Standard by NERC** — NERC shall evaluate and recommend whether a proposed Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections that could serve as a basis for rebutting the presumption of validity of the Regional Reliability Standard. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning the proposed Regional Reliability Standard, shall have the option of

presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, NERC's recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

3.4 **Applicable Governmental Authority Approval** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

3.5 **Enforcement of Interconnection-wide Regional Reliability Standard** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

4. **Procedure for Developing Non-Interconnection-Wide Regional Reliability Standards** — Regional Entities that are not organized on an Interconnection-wide basis may propose Regional Reliability Standards to apply within their respective Regions. Such Regional Reliability Standards may be developed through the NERC Reliability Standards development procedure, or alternatively, through a Regional Reliability Standards development procedure that has been approved by NERC.

4.1 **No Presumption of Validity** — Regional Reliability Standards that are not proposed to be applied on an Interconnection-wide basis are not presumed to be valid but may be demonstrated by the proponent to be valid.

4.2 **Notice and Comment Procedure for Non-Interconnection-wide Regional Reliability Standards** — NERC shall publicly notice and request comment on the proposed Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to comment on or resolve any objections identified in the comments and may choose to withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for adoption by NERC.

4.3 **NERC Adoption of Non-Interconnection-wide Regional Reliability Standards** — NERC shall evaluate and recommend whether a proposed non-Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, the recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

4.4 **Applicable Governmental Authority Approval** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

4.5 **Enforcement of Non-Interconnection-wide Regional Reliability Standards** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

5. **Appeals** — A Regional Entity shall have the right to appeal NERC's decision not to adopt a proposed Regional Reliability Standard or Variance to the Commission or other Applicable Governmental Authority.

313. Other Regional Criteria, Guides, Procedures, Agreements, Etc.

1. **Regional Criteria** — Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy. Regional Criteria may include specific acceptable 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 authority delegated by NERC pursuant to delegation agreements and do not require NERC approval.

2. **Catalog of Regional Criteria** — NERC shall maintain a current catalog of Regional Criteria. Regional Entities shall provide a catalog listing of Regional Criteria to NERC and shall notify NERC of changes to the listing. Regional Entities shall provide any listed document to NERC upon written request.

314. Conflicts with Statutes, Regulations, and Orders

Notice of Potential Conflict — If a Bulk Power System owner, operator, or user determines that a NERC or Regional Reliability Standard may conflict with a function, rule, order, tariff, rate schedule, legislative requirement or agreement that has been accepted, approved, or ordered by a governmental authority affecting that entity, the entity shall expeditiously notify the governmental authority, NERC, and the relevant Regional Entity of the conflict.

1. **Determination of Conflict —** NERC, upon request of the governmental authority, may advise the governmental authority regarding the conflict and propose a resolution of the conflict, including revision of the Reliability Standard if appropriate.

2. **Regulatory Precedence** — Unless otherwise ordered by a governmental authority, the affected Bulk Power System owner, operator, or user shall continue to follow the function, rule, order, tariff, rate schedule, legislative requirement, or agreement accepted, approved, or ordered by the governmental authority until the governmental authority finds that a conflict exists and orders a remedy and such remedy is affected.

315. Revisions to NERC Standard Processes Manual

Any person or entity may submit a written request to modify NERC *Standard Processes Manual*. Consideration of the request and development of the revision shall follow the process defined in the NERC *Standard Processes Manual*. Upon approval by the Board, the revision shall be submitted to the Applicable Governmental Authorities for approval. Changes shall become effective only upon approval by the Applicable Governmental Authorities or on a date designated by the Applicable Governmental Authorities or as otherwise applicable in a particular jurisdiction.

316. Accreditation

NERC shall seek and maintain accreditation of the NERC Reliability Standards development process by the American National Standards Institute.

317. Periodic Review of Reliability Standards

NERC shall complete a periodic review of each NERC Reliability Standard in accordance with the NERC *Standard Processes Manual*. The standards process manager shall be responsible for administration of the periodic review of Reliability Standards. As a result of this review, the NERC Reliability Standard shall be reaffirmed, revised, or withdrawn. If the review indicates a need to revise or withdraw the Reliability Standard, a request for revision or withdrawal shall be prepared, submitted and addressed in accordance with the NERC *Standard Processes Manual*.

318. Coordination with the North American Energy Standards Board

NERC shall maintain a close working relationship with the North American Energy Standards Board and ISO/RTO Council to ensure effective coordination of wholesale electric business practice standards and market protocols with the NERC Reliability Standards.

319. Archived Standards Information

NERC shall maintain a historical record of Reliability Standards information that is no longer maintained on-line. For example, Reliability Standards that have been retired may be removed from the on-line system. Archived information shall be retained indefinitely as practical, but in no case less than six years or one complete Reliability Standards review cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by the NERC standards information manager of a written request.

320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels

1. **Development of Violation Risk Factors and Violation Severity Levels** — NERC shall follow the process for developing Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as set forth in the Standard Processes Manual, Appendix 3A to these Rules of Procedure.

2. **Remands of Directed Revision of VRFs and VSLs by Applicable Governmental Authorities** — If an Applicable Governmental Authority remands or directs a revision to a Board-approved VRF or VSL assignment, the NERC director of standards, after consulting with the standard drafting team, Standards Committee, and the NERC director of compliance operations, will recommend to the Board one of the following actions: (1) filing a request for clarification; (2) filing for rehearing or for review of the Applicable Governmental Authority decision; or (3) approval of the directed revisions to the VRF or VSL. If and to the extent time is available prior to the deadline for the Board's decision, an opportunity for interested parties to comment on the action taken will be provided.

3. **Alternative Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels** — In the event the Reliability Standards development process fails to produce Violation Risk Factors or Violation Severity Levels for a particular Reliability Standard in a timely manner, the Board of Trustees may approve Violation Risk Factors or Violation Severity Levels for that Reliability Standard after notice and opportunity for comment. In approving VRFs and VSLs, the Board shall consider the inputs of the Member Representatives Committee, affected stakeholders and NERC staff.

321. Special Rule to Address Certain Regulatory Directives

In circumstances where this Rule 321 applies, the Board of Trustees shall have the authority to take one or more of the actions set out below. The Board of Trustees shall have the authority to choose which one or more of the actions are appropriate to the circumstances and need not take these actions in sequential steps.

1. The Standards Committee shall have the responsibility to ensure that standards drafting teams address specific matters that are identified in directives issued by Applicable Governmental Authorities. If the Board of Trustees is presented with a proposed Reliability Standard that fails to address such directives, the Board of Trustees has the authority to remand, with instructions (including establishing a timetable for action), the proposed Reliability Standard to the Standards Committee.

2. Upon a written finding by the Board of Trustees that a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to remand the proposed Reliability Standard to the Standards Committee, with instructions to (i) convene a public technical conference to discuss the issues surrounding the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified; (ii) working with NERC staff, prepare a memorandum discussing the issues, an analysis of the alternatives considered and other appropriate matters; and (iii) re-ballot the proposed Reliability Standard one additional time, with such adjustments in the schedule as are necessary to meet the deadline contained in paragraph 2.1 of this Rule.

   2.1 Such a re-ballot shall be completed within forty-five (45) days of the remand. The Standards Committee memorandum shall be included in the materials made available to the ballot pool in connection with the re-ballot.

   2.2 In any such re-ballot, negative votes without comments related to the proposal shall be counted for purposes of establishing a quorum, but only affirmative votes and negative votes with comments related to the proposal shall be counted for purposes of determining the number of votes cast and whether the proposed Reliability Standard has been approved.

3. If the re-balloted proposed Reliability Standard achieves at least an affirmative two-thirds majority vote of the weighted Segment votes cast, with a quorum established, then the proposed Reliability Standard shall be deemed approved by the ballot pool and shall be considered by the Board of Trustees for approval.

4. If the re-balloted proposed Reliability Standard fails to achieve at least an affirmative two-thirds majority vote of the weighted Segment votes cast, but does

achieve at least a sixty percent affirmative majority of the weighted Segment votes cast, with a quorum established, then the Board of Trustees has the authority to consider the proposed Reliability Standard for approval under the following procedures:

4.1 The Board of Trustees shall issue notice of its intent to consider the proposed Reliability Standard and shall solicit written public comment particularly focused on the technical aspects of the provisions of the proposed Reliability Standard that address the specific matter identified in the regulatory directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

4.2 The Board of Trustees may, in its discretion, convene a public technical conference to receive additional input on the matter.

4.3 After considering the developmental record, the comments received during balloting and the additional input received under paragraphs 4.1 and 4.2 of this Rule, the Board of Trustees has authority to act on the proposed Reliability Standard.

4.3.1 If the Board of Trustees finds that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to approve the proposed Reliability Standard and direct that it be filed with Applicable Governmental Authorities with a request that it be made effective.

4.3.2 If the Board of Trustees is unable to find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to treat the proposed Reliability Standard as a draft Reliability Standard and direct that the draft Reliability Standard and complete developmental record, including the additional input received under paragraphs 4.1 and 4.2 of this Rule, be filed with the Applicable Governmental Authorities as a compliance filing in response to the order giving rise to the regulatory directive, along with a recommendation that the Reliability Standard not be made effective and an explanation of the basis for the recommendation.

5. Upon a written finding by the Board of Trustees that standard drafting team has failed to develop, or a ballot pool has failed to approve, a proposed Reliability

Standard that contains a provision to address a specific matter identified in a directive issued by an Applicable Governmental Authority, the Board of Trustees has the authority to direct the Standards Committee (with the assistance of stakeholders and NERC staff) to prepare a draft Reliability Standard that addresses the regulatory directive, taking account of the entire developmental record pertaining to the matter. If the Standards Committee fails to prepare such draft Reliability Standard, the Board of Trustees may direct NERC management to prepare such draft Reliability Standard.

5.1 The Board of Trustees may, in its discretion, convene a public technical conference to receive input on the matter. The draft Reliability Standard shall be posted for a 45-day public comment period.

5.2 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees finds that the draft Reliability Standard, with such modifications as the Board of Trustees determines are appropriate in light of the comments received, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to approve the draft Reliability Standard and direct that the proposed Reliability Standard be filed with Applicable Governmental Authorities with a request that the proposed Reliability Standard be made effective.

5.3 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees is unable to find that the draft Reliability Standard, even with modifications, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to direct that the draft Reliability Standard and complete developmental record be filed as a compliance filing in response to the regulatory directive with the Applicable Governmental Authority issuing the regulatory directive, with a recommendation that the draft Reliability Standard not be made effective.

5.4 The filing of the Reliability Standard under either paragraph 5.2 or paragraph 5.3 of this Rule shall include an explanation of the basis for the decision by the Board of Trustees.

5.5 A Reliability Standard approved under paragraph 5 of this Rule shall not be eligible for submission as an American National Standard.

6. NERC shall on or before March 31st of each year file a report with Applicable Governmental Authorities on the status and timetable for addressing each outstanding directive to address a specific matter received from an Applicable Governmental Authority.

SECTION 400 — COMPLIANCE ENFORCEMENT

401. Scope of the NERC Compliance Monitoring and Enforcement Program

1. **Components of the NERC Compliance Monitoring and Enforcement Program** — NERC shall develop and implement a NERC Compliance Monitoring and Enforcement Program to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North American in which NERC and/or a Regional Entity (pursuant to a delegation agreement with NERC that has been approved by the Applicable Governmental Authority) has been given enforcement authority. There are four distinct parts of the NERC Compliance Monitoring and Enforcement Program: (1) NERC's oversight of the Regional Entity Compliance Monitoring and Enforcement Programs (Section 402), (2) the definition of the required Regional Entity Compliance Monitoring and Enforcement Program attributes (Section 403), (3) NERC's monitoring of Regional Entity compliance with Reliability Standards (Section 404), and (4) the monitoring of compliance with Reliability Standards that are applicable to NERC (Sections 405–406).

2. **Who Must Comply** — Where required by applicable legislation, regulation, rule or agreement, all Bulk Power System owners, operators, and users, Regional Entities, and NERC, are required to comply with all approved NERC Reliability Standards at all times. Regional Reliability Standards and Variances approved by NERC and the Applicable Governmental Authority shall be considered NERC Reliability Standards and shall apply to all Bulk Power System owners, operators, or users responsible for meeting those Reliability Standards within the Regional Entity boundaries, whether or not the Bulk Power System owner, operator, or user is a member of the Regional Entity.

3. **Data Access** — All Bulk Power System owners, operators, and users shall provide to NERC and the applicable Regional Entity such information as is necessary to monitor compliance with the Reliability Standards. NERC and the applicable Regional Entity will define the data retention and reporting requirements in the Reliability Standards and compliance reporting procedures.

4. **Role of Regional Entities in the Compliance Monitoring and Enforcement Program** — Each Regional Entity that has been delegated authority through a delegation agreement or other legal instrument approved by the Applicable Governmental Authority shall, in accordance with the terms of the approved delegation agreement, administer a Regional Entity Compliance Monitoring and Enforcement program to meet the NERC Compliance Monitoring and Enforcement Program goals and the requirements in this Section 400.

5. **Program Continuity** — NERC will ensure continuity of compliance monitoring and enforcement within the geographic boundaries of a Regional Entity in the event that NERC does not have a delegation agreement, or the Regional Entity withdraws from the agreement or does not operate its Compliance Monitoring and

Enforcement Program in accordance with the delegation agreement or other applicable requirements.

5.1 Should NERC not have a delegation agreement with a Regional Entity covering a geographic area, or a Regional Entity withdraws from an existing delegation agreement or the delegation agreement is otherwise terminated, NERC will directly administer the Compliance Monitoring and Enforcement Program applicable to owners, operators and users of the Bulk Power System within that geographic area.

1. This monitoring and enforcement will be accomplished by NERC and Compliance Staff from another approved Regional Entity.

2. If an existing delegation agreement with a Regional Entity is terminating, the Regional Entity shall promptly provide to NERC all relevant compliance information regarding Registered Entities, contacts, prior compliance information and actions, Mitigation Plans, and Remedial Action Directives for the period in which the Regional Entity was responsible for administering the Compliance Monitoring and Enforcement Program.

3. NERC will levy and collect all Penalties directly and will utilize any Penalty monies collected to offset the expenses of administering the Compliance Monitoring and Enforcement Program for the geographic area.

5.2 Should a Regional Entity seek to withdraw from its delegation agreement, NERC will seek agreement from another Regional Entity to amend its delegation agreement with NERC to extend that Regional Entity's boundaries for compliance monitoring and enforcement. In the event no Regional Entity is willing to accept this responsibility, NERC will administer the Compliance Monitoring and Enforcement Program within the geographical boundaries of the Regional Entity seeking to withdraw from the delegation agreement, in accordance with Section 401.5.1.

6. **Risk Elements** — NERC, with input from the Regional Entities, stakeholders, and regulators, shall at least annually identify risk elements to prioritize risks to the reliability of the Bulk Power System. These risk elements and related NERC Reliability Standards and Requirements are to be considered for compliance oversight in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan. NERC identifies the risk elements using data including, but not limited to: compliance findings; event analysis experience; data analysis; and the expert judgment of NERC and Regional Entity staff, committees, and subcommittees. NERC uses these risk elements to identify and prioritize interconnection and continent-wide risks to the reliability of the Bulk Power System. These identified risks, as well as risks to the reliability of the Bulk Power System identified by Regional Entities for their footprint, represent the

focus for monitoring activities in the upcoming year, and become inputs for developing oversight plans for individual Registered Entities. Compliance is required, and NERC and the Regional Entities have authority to monitor compliance, with all applicable NERC Reliability Standards whether or not they are identified as areas of focus to be considered for compliance oversight in the annual NERC Compliance Monitoring and Enforcement Program Implementation Plan or are included in a Regional Entity's oversight plan for the Registered Entity.

7. **Penalties, Sanctions, and Remedial Action Directives** — NERC and Regional Entities will apply Penalties, sanctions, and Remedial Action Directives that bear a reasonable relation to the seriousness of a violation and take into consideration timely remedial efforts as defined in the NERC *Sanction Guidelines*, which is incorporated into these rules as **Appendix 4B**.

8. **Multiple Enforcement Actions** – A Registered Entity shall not be subject to an enforcement action by NERC and a Regional Entity, or by more than one Regional Entity (unless the Registered Entity is registered in more than one Region in which the violation occurred), for the same violation.

9. **Records** — NERC shall maintain a record of each compliance submission, including Self-Reported, Possible, Alleged, and Confirmed Violations of approved Reliability Standards; associated Penalties, sanctions, Remedial Action Directives and settlements; and the status of mitigation actions.

10. **Confidential Information** — NERC will treat all Possible and Alleged Violations of Reliability Standards and matters related to a Compliance Monitoring and Enforcement Program process, including the status of any Compliance Investigation or other Compliance Monitoring and Enforcement Program process, as confidential in accordance with Section 1500.

    The types of information that will be considered confidential and will not (subject to statutory and regulatory requirements) be disclosed in any public information reported by NERC are identified in Section 1500. Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident, will be identified and protected from public disclosure as Critical Energy Infrastructure Information in accordance with Section 1500.

    The Regional Entity and NERC shall give Bulk Power System owners, operators, and users a reasonable opportunity to demonstrate that information concerning a violation is confidential before such report is disclosed to the public.

11. **Public Posting** — When the affected Bulk Power System owner, operator, or user either agrees with a Possible or Alleged Violation(s) of a Reliability Standard(s) or a report of a Compliance Audit or Compliance Investigation, or enters into a settlement agreement concerning a Possible or Alleged Violation(s), or the time for submitting an appeal is passed, or all appeals processes are complete, NERC

shall, subject to the confidentiality requirements of these Rules of Procedure, publicly post each Confirmed Violation, Penalty or sanction, settlement agreement, and final Compliance Audit or Compliance Investigation report, on its website. As required by an Applicable Governmental Authority, NERC will also post information concerning noncompliance disposed of as Compliance Exceptions, subject to Section 1500 of these Rules of Procedures.

11.1 Each Bulk Power System owner, operator, or user may provide NERC with a statement to accompany the Confirmed Violation or report to be posted publicly. The statement must be on company letterhead and include a signature, as well as the name and title of the person submitting the information.

11.2 In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information (*NERC Security Guidelines for the Electricity Sector — Protecting Potentially Sensitive Information* may be used as a guide) or other Confidential Information shall be redacted in accordance with Section 1500 and not be released publicly.

11.3 Subject to redaction of Critical Energy Infrastructure Information or other Confidential Information, for each Confirmed Violation or settlement relating to a Possible Violation or an Alleged Violation, the public posting shall include the name of any relevant entity, the nature, time period, and circumstances of such Possible, Alleged or Confirmed Violation, any Mitigation Plan or other Mitigating Activities to be implemented by the Registered Entity in connection with the Confirmed Violation or settlement, and sufficient facts to assist owners, operators and users of the Bulk Power System to evaluate whether they have engaged in or are engaging in similar activities.

12. **Violation Information Review** — NERC Compliance Staff shall periodically review and analyze all reports of Possible, Alleged and Confirmed Violations to identify trends and other pertinent reliability issues.

402. NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs

1. **NERC Monitoring Program** — NERC shall have a program to monitor the Compliance Monitoring and Enforcement Program of each Regional Entity that has been delegated authority. The objective of this monitoring program shall be to ensure that the Regional Entity carries out its Compliance Monitoring and Enforcement Program in accordance with these Rules of Procedure and the terms of the delegation agreement, and to ensure consistency and fairness of the Regional Entity's Compliance Monitoring and Enforcement Program. Oversight and monitoring by NERC shall be accomplished through an annual Compliance Monitoring and Enforcement Program review, program audits, and regular

evaluations of Regional Entity Compliance Monitoring and Enforcement Program performance as described below.

1.1 **NERC Review of Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans** — NERC shall require each Regional Entity to submit for review and approval an annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan. NERC shall review each annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan and shall accept the plan if it meets NERC requirements and the requirements of the delegation agreement.

1.2 **Regional Entity Compliance Monitoring and Enforcement Program Evaluation** — NERC shall annually evaluate the goals, tools, and procedures of each Regional Entity Compliance Monitoring and Enforcement Program to determine the effectiveness of each Regional Entity Compliance Monitoring and Enforcement Program, using criteria developed by the NERC Compliance and Certification Committee.

1.3 **Regional Entity Compliance Monitoring and Enforcement Program Audit** — At least once every five years, NERC shall conduct an audit to evaluate how each Regional Entity Compliance Monitoring and Enforcement Program implements the NERC Compliance Monitoring and Enforcement Program. The evaluation shall be based on these Rules of Procedure, including Appendix 4C, the delegation agreement, directives in effect pursuant to the delegation agreement, approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plans, required Compliance Monitoring and Enforcement Program attributes, and the NERC Compliance Monitoring and Enforcement Program procedures. These evaluations shall be provided to the Applicable Governmental Authorities to demonstrate the effectiveness of each Regional Entity. In addition, audits of Cross-Border Regional Entities shall cover applicable requirements imposed on the Regional Entity by statute, regulation, or order of, or agreement with, provincial governmental and/or regulatory authorities for which NERC has auditing responsibilities over the Regional Entity's compliance with such requirements within Canada or Mexico. Participation of a representative of an Applicable Governmental Authority shall be subject to the limitations of sections 3.1.6 and 8.0 of Appendix 4C of these Rules of Procedure regarding disclosures of non-public compliance information related to other jurisdictions. NERC shall maintain an audit procedure containing the requirements, steps, and timelines to conduct an audit of each Regional Entity Compliance Monitoring and Enforcement Program. The current procedure is contained in the NERC Audit of Regional Entity Compliance Programs, which is incorporated into these rules as **Appendix 4A**.

1.3.1. NERC shall establish a program to audit bulk power system owners, operators, and users operating within a regional entity to verify the findings of previous compliance audits conducted by the regional entity to evaluate how well the regional entity compliance enforcement program is meeting its delegated authority and responsibility.

1.4 Applicable Governmental Authorities will be allowed to participate as an observer in any audit conducted by NERC of a Regional Entity's Compliance Monitoring and Enforcement Program. A representative of the Regional Entity being audited will be allowed to participate in the audit as an observer.

2. **Consistency Among Regional Compliance Monitoring and Enforcement Programs** — To provide for a consistent Compliance Monitoring and Enforcement Program for all Bulk Power System owners, operators, and users required to comply with approved Reliability Standards, NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program, which is incorporated into these rules of procedure as **Appendix 4C**. Any differences in Regional Entity Compliance Monitoring and Enforcement Program methods, including determination of violations and Penalty assessment, shall be justified on a case-by-case basis and fully documented in each Regional Entity delegation agreement.

2.1 NERC shall ensure that each of the Regional Entity Compliance Monitoring and Enforcement Programs meets these Rules of Procedure, including **Appendix 4C**, and follows the terms of the delegation agreement and the approved annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan.

2.2 NERC shall maintain a single, uniform Compliance Monitoring and Enforcement Program in **Appendix 4C** containing the procedures to ensure the consistency and fairness of the processes used to determine Regional Entity Compliance Monitoring and Enforcement Program findings of compliance and noncompliance, and the application of Penalties and sanctions.

2.3 NERC shall periodically conduct Regional Entity compliance manager forums. These forums shall use the results of Regional Entity Compliance Monitoring and Enforcement Program audits and findings of NERC Compliance Staff to identify and refine Regional Entity Compliance Monitoring and Enforcement Program differences into a set of best practices over time.

3. **Information Collection and Reporting** — NERC and the Regional Entities shall implement data management procedures that address data reporting requirements, data integrity, data retention, data security, and data confidentiality.

4. **Violation Disclosure** — NERC shall disclose all Confirmed Violations and maintain as confidential Possible Violations and Alleged Violations, according to the reporting and disclosure process in **Appendix 4C**.

5. **Authority to Determine Noncompliance, Levy Penalties and Sanctions, and Issue Remedial Action Directives** — NERC and Regional Entity Compliance Staff shall have the authority and responsibility to make initial determinations of compliance or noncompliance, and where authorized by the Applicable Governmental Authorities or where otherwise authorized, to determine Penalties and sanctions for noncompliance with a Reliability Standard, and issue Remedial Action Directives. Regional Entity boards or a compliance panel reporting directly to the Regional Entity board will be vested with the authority for the overall Regional Entity Compliance Monitoring and Enforcement Program and have the authority to impose Penalties and sanctions on behalf of NERC, where authorized by applicable legislation or agreement. Remedial Action Directives may be issued by NERC or a Regional Entity that is aware of a Bulk Power System owner, operator, or user that is, or is about to engage in an act or practice that would result, in noncompliance with a Reliability Standard, where such Remedial Action Directive is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat. If, after receiving such a Remedial Action Directive, the Bulk Power System owner, operator, or user does not take appropriate action to avert a violation of a Reliability Standard, NERC may petition the Applicable Governmental Authority to issue a compliance order.

6. **Due Process** — NERC shall establish and maintain a fair, independent, and nondiscriminatory appeals process. The appeals process is set forth in Sections 408-410. The process shall allow Bulk Power System owners, operators, and users to appeal the Regional Entity's findings of noncompliance and to appeal Penalties, sanctions, and Remedial Action Directives that are levied by the Regional Entity. Appeals beyond the NERC process will be heard by the Applicable Governmental Authority.

   The appeals process will also allow for appeals to NERC of any findings of noncompliance issued by NERC to a Regional Entity for Reliability Standards and Requirements where the Regional Entity is monitored for compliance to a Reliability Standard. No monetary Penalties will be levied in these matters; however sanctions, remedial actions, and directives to comply may be applied by NERC.

7. **Conflict Disclosure** — NERC shall disclose to the appropriate governmental authorities any potential conflicts between a market rule and the enforcement of a Regional Reliability Standard.

8. **Confidentiality** — To maintain the integrity of the NERC Compliance Monitoring and Enforcement Program, NERC and Regional Entity staff, Compliance Audit team members, and committee members shall maintain the

confidentiality of information obtained and shared during compliance monitoring and enforcement processes including Compliance Investigations, Compliance Audits, Spot Checks, drafting of reports, appeals, and closed meetings.

8.1 NERC and the Regional Entity shall have in place appropriate codes of conduct and confidentiality agreements for staff and other Compliance Monitoring and Enforcement Program participants.

8.2 Individuals not bound by NERC or Regional Entity codes of conduct who serve on compliance-related committees or Compliance Audit teams shall sign a NERC confidentiality agreement prior to participating on the committee or Compliance Audit team.

8.3 Information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall not be distributed outside of a committee or team, nor released publicly. Other information subject to confidentiality is identified in Section 1500.

8.4 In the event that a staff, committee, or Compliance Audit team member violates any of the confidentiality rules set forth above, the staff, committee, or Compliance Audit team member and any member organization with which the individual is associated may be subject to appropriate action by the Regional Entity or NERC, including prohibiting participation in future Compliance Monitoring and Enforcement Program activities.

9. **Auditor Training** — NERC shall develop and provide training in auditing skills to all people who participate in NERC and Regional Entity Compliance Audits. Training for NERC and Regional Entity personnel and others who serve as Compliance Audit team leaders shall be more comprehensive than training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

403. Required Attributes of Regional Entity Compliance Monitoring and Enforcement Programs

Each Regional Entity Compliance Monitoring and Enforcement Program shall promote excellence in the enforcement of Reliability Standards. To accomplish this goal, each Regional Entity Compliance Monitoring and Enforcement Program shall (i) conform to and comply with the NERC uniform Compliance Monitoring and Enforcement Program, **Appendix 4C** to these Rules of Procedure, except to the extent of any deviations that are stated in the Regional Entity's delegation agreement, and (ii) meet all of the attributes set forth in this Section 403.

Program Structure

1. **Independence** — Each Regional Entity's governance of its Compliance Monitoring and Enforcement Program shall exhibit independence, meaning the Compliance Monitoring and Enforcement Program shall be organized so that its compliance monitoring and enforcement activities are carried out separately from other activities of the Regional Entity. The Compliance Monitoring and Enforcement Program shall not be unduly influenced by the Bulk Power System owners, operators, and users being monitored or other Regional Entity activities that are required to meet the Reliability Standards. Regional Entities must include rules providing that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

2. **Exercising Authority** — Each Regional Entity Compliance Monitoring and Enforcement Program shall exercise the responsibility and authority in carrying out the delegated functions of the NERC Compliance Monitoring and Enforcement Program in accordance with delegation agreements and **Appendix 4C**. These functions include but are not limited to: data gathering, data reporting, Compliance Investigations, Compliance Audit activities, evaluating compliance and noncompliance, imposing Penalties and sanctions, and approving and tracking mitigation actions.

3. **Delegation of Authority** — To maintain independence, fairness, and consistency in the NERC Compliance Monitoring and Enforcement Program, a Regional Entity shall not sub-delegate its Compliance Monitoring and Enforcement Program duties to entities or persons other than the Regional Entity Compliance Staff, unless (i) required by statute or regulation in the applicable jurisdiction, or (ii) by agreement with express approval of NERC and of FERC or other Applicable Governmental Authority, to another Regional Entity.

4. **Hearings of Contested Findings or Sanctions —** The Regional Entity board or compliance panel reporting directly to the Regional Entity board (with appropriate recusal procedures) will be vested with the authority for conducting compliance hearings in which any Bulk Power System owner, operator, or user provided a Notice of Alleged Violation may present facts and other information to contest a Notice of Alleged Violation or any proposed Penalty, sanction, any Remedial Action Directive, or any Mitigation Plan component. Compliance hearings shall be conducted in accordance with the Hearing Procedures set forth in Attachment 2 to **Appendix 4C**. If a stakeholder body serves as the Hearing Body, no two industry sectors may control any decision and no single segment may veto any matter related to compliance after recusals.

Program Resources

5. **Regional Entity Compliance Staff** — Each Regional Entity shall have sufficient resources to meet delegated compliance monitoring and enforcement responsibilities, including the necessary professional staff to manage and implement the Regional Entity Compliance Monitoring and Enforcement Program.

6. **Regional Entity Compliance Staff Independence** — The Regional Entity Compliance Staff shall be capable of and required to make all determinations of compliance and noncompliance and determine Penalties, sanctions, and Remedial Action Directives and to review and accept Mitigation Plans and other Mitigating Activities.

   6.1 Regional Entity Compliance Staff shall not have a conflict of interest, real or perceived, in the outcome of compliance monitoring and enforcement processes, reports, or sanctions. The Regional Entity shall have in effect a conflict of interest policy.

   6.2 Regional Entity Compliance Staff shall have the authority and responsibility to carry out compliance monitoring and enforcement processes (with the input of industry subject matter experts), make determinations of compliance or noncompliance, and levy Penalties and sanctions without interference or undue influence from Regional Entity members and their representative or other industry entities.

   6.3 Regional Entity Compliance Staff may call upon independent technical subject matter experts who have no conflict of interest in the outcome of the compliance monitoring and enforcement process to provide technical advice or recommendations in the determination of compliance or noncompliance.

   6.4 Regional Entity Compliance Staff shall abide by the confidentiality requirements contained in Section 1500 and **Appendix 4C** of these Rules of Procedure, the NERC delegation agreement and other confidentiality agreements required by the NERC Compliance Monitoring and Enforcement Program.

   6.5 Contracting with independent consultants or others working for the Regional Entity Compliance Monitoring and Enforcement Program shall be permitted provided the individual has not received compensation from a Bulk Power System owner, operator, or user being monitored for a period of at least the preceding six months and owns no financial interest in any Bulk Power System owner, operator, or user being monitored for compliance to the Reliability Standard, regardless of where the Bulk Power System owner, operator, or user operates. Any such individuals for the purpose of these Rules of Procedure shall be considered as augmenting Regional Entity Compliance Staff.

7. **Use of Industry Subject Matter Experts and Regional Entity Members** — Industry experts and Regional Entity members may be called upon to provide their technical expertise in Compliance Monitoring and Enforcement Program activities.

7.1 The Regional Entity shall have procedures defining the allowable involvement of industry subject matter experts and Regional Entity members. The procedures shall address applicable antitrust laws and conflicts of interest.

7.2 Industry subject matter experts and Regional Entity members shall have no conflict of interest or financial interests in the outcome of their activities.

7.3 Regional Entity members and industry subject matter experts, as part of teams or Regional Entity committees, may provide input to the Regional Entity Compliance Staff so long as the authority and responsibility for (i) evaluating and determining compliance or noncompliance and (ii) levying Penalties, sanctions, or Remedial Action Directives shall not be delegated to any person or entity other than the Compliance Staff of the Regional Entity. Industry subject matter experts, Regional Entity members, or Regional Entity committees shall not make determinations of noncompliance or levy Penalties, sanctions, or Remedial Action Directives. Any committee involved shall be organized so that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

7.4 Industry subject matter experts and Regional Entity members shall sign a confidentiality agreement appropriate for the activity being performed.

7.5 All industry subject matter experts and Regional Entity members participating in Compliance Audits and Compliance Investigations shall successfully complete auditor training provided by NERC or the Regional Entity prior to performing these activities

Program Design

8. **Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan Content** — All approved Reliability Standards shall be included in the Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan for all Bulk Power System owners, operators, and users within the defined boundaries of the Regional Entity. Compliance to approved Regional Reliability Standards is applicable only within the Region of the Regional Entity that submitted those particular Regional Reliability Standards for approval. NERC will identify the risk elements and related Reliability Standards and Requirements to be considered by the Regional Entity in a given year in developing oversight plans for individual Registered Entities.

9. **Antitrust Provisions** — Each Regional Entity's Compliance Monitoring and Enforcement Program shall be structured and administered to abide by U.S. antitrust law and Canadian competition law.

10. **Information Submittal** — All Bulk Power System owners, operators, and users within the Regional Entity responsible for complying with Reliability Standards shall submit timely and accurate information when requested by the Regional Entity or NERC. NERC and the Regional Entities shall preserve any mark of confidentiality on information submitted pursuant to Section 1502.1.

    10.1 Each Regional Entity has the authority to collect the necessary information to determine compliance and shall develop processes for gathering data from the Bulk Power System owners, operators, and users the Regional Entity monitors.

    10.2 The Regional Entity or NERC has the authority to request information from Bulk Power System owners, operators, and users pursuant to Section 401.3 or this Section 403.10 without invoking a specific compliance monitoring and enforcement process in **Appendix 4C**, for purposes of determining whether to pursue one such process in a particular case and/or validating in the enforcement phase of a matter the conclusions reached through the compliance monitoring and enforcement process(es).

    10.3 When required or requested, the Regional Entities shall report information to NERC promptly and in accordance with **Appendix 4C** and other NERC procedures.

    10.4 Regional Entities shall notify NERC of all Possible, Alleged and Confirmed Violations of NERC Reliability Standards by Registered Entities over which the Regional Entity has compliance monitoring and enforcement authority, in accordance with **Appendix 4C**.

    10.5 A Bulk Power System owner, operator, or user found in noncompliance with a Reliability Standard shall submit a Mitigation Plan with a timeline addressing how the noncompliance will be corrected, unless an enforcement process is used that does not require a Mitigation Plan. The Regional Entity Compliance Staff shall review and accept the Mitigation Plan in accordance with **Appendix 4C**.

    10.6 An officer of a Bulk Power System owner, operator, or user shall certify as accurate all compliance data Self-Reported to the Regional Entity Compliance Monitoring and Enforcement Program.

    10.7 Regional Entities shall develop and implement procedures to verify the compliance information submitted by Bulk Power System owners, operators, and users.

11. **Compliance Audits of Bulk Power System Owners, Operators, and Users** — Each Regional Entity will maintain and implement a program of proactive Compliance Audits of Bulk Power System owners, operators, and users responsible for complying with Reliability Standards, in accordance with **Appendix 4C**. A Compliance Audit is a process in which a detailed review of the

activities of a Bulk Power System owner, operator, or user is performed to determine if that Bulk Power System owner, operator, or user is complying with approved Reliability Standards.

11.1 For an entity registered as a Balancing Authority, Reliability Coordinator, or Transmission Operator, the Compliance Audit will be performed at least once every three years. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, Compliance Audits shall be performed on a schedule established by NERC.

11.2 Compliance Audits of Balancing Authorities, Reliability Coordinators, and Transmission Operators will include a component at the audited entity's site. For other Bulk Power System owners, operators, and users on the NERC Compliance Registry, the Compliance Audit may be either an on-site Compliance Audit or based on review of documents, as determined to be necessary and appropriate by NERC or Regional Entity Compliance Staff.

11.3 Compliance Audits must include a detailed review of the activities of the Bulk Power System owner, operator, or user to determine if the Bulk Power System owner, operator, or user is complying with all approved Reliability Standards identified for audit by NERC. The Compliance Audit shall include a review of supporting documentation and evidence used by the Bulk Power System owner, operator or user to demonstrate compliance for an appropriate period prior to the Compliance Audit.

12. **Confidentiality of Compliance Monitoring and Enforcement Processes** — All compliance monitoring and enforcement processes, and information obtained from such processes, are to be non-public and treated as confidential in accordance with Section 1500 and **Appendix 4C** of these Rules of Procedure, unless NERC, the Regional Entity or FERC or another Applicable Governmental Authority with jurisdiction determines a need to conduct a Compliance Monitoring and Enforcement Program process on a public basis, provided, that NERC and the Regional Entities shall publish (i) schedules of Compliance Audits scheduled in each year, (ii) a public report of each Compliance Audit, and (iii) Notices of Penalty and settlement agreements. Advance authorization from the Applicable Governmental Authority is required to make public any compliance monitoring and enforcement process or any information relating to a compliance monitoring and enforcement process, or to permit interventions when determining whether to impose a Penalty. This prohibition on making public any compliance monitoring and enforcement process does not prohibit NERC or a Regional Entity from publicly disclosing (i) the initiation of or results from an analysis of a significant system event under Section 807 or of off-normal events or system performance under Section 808, or (ii) information of general applicability and usefulness to owners, operators, and users of the Bulk Power System concerning reliability and compliance matters, so long as specific allegations or conclusions

regarding Possible or Alleged Violations of Reliability Standards are not included in such disclosures.

13. **Critical Energy Infrastructure Information** — Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident will be identified and protected from public disclosure as Critical Energy Infrastructure Information. In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information shall be redacted according to NERC procedures and shall not be released publicly.

14. **Penalties, Sanctions, and Remedial Action Directives** — Each Regional Entity will apply all Penalties, sanctions, and Remedial Action Directives in accordance with the approved *Sanction Guidelines*, **Appendix 4B** to these Rules of Procedure. Any changes to the *Sanction Guidelines* to be used by any Regional Entity must be approved by NERC and submitted to the Applicable Governmental Authority for approval. All Confirmed Violations, Penalties, and sanctions, including Confirmed Violations, Penalties and sanctions specified in a Regional Entity Hearing Body decision, will be provided to NERC for review and filing with Applicable Governmental Authorities as a Notice of Penalty, in accordance with **Appendix 4C**.

15. **Regional Entity Hearing Process** — Each Regional Entity Compliance Monitoring and Enforcement Program shall establish and maintain a fair, independent, and nondiscriminatory process for hearing contested violations and any Penalties or sanctions levied, in conformance with Attachment 2 to **Appendix 4C** to these Rules of Procedure and any deviations therefrom that are set forth in the Regional Entity's delegation agreement. The hearing process shall allow Bulk Power System owners, operators, and users to contest findings of compliance violations, any Penalties and sanctions that are proposed to be levied, proposed Remedial Action Directives, and components of proposed Mitigation Plans. The Regional Entity hearing process shall be conducted before the Regional Entity board or a balanced committee established by and reporting to the Regional Entity board as the final adjudicator at the Regional Entity level, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions. The Regional Entity hearing process shall (i) include provisions for recusal of any members of the Hearing Body with a potential conflict of interest, real or perceived, from all compliance matters considered by the Hearing Body for which the potential conflict of interest exists and (ii) provide that no two industry sectors may control any decision and no single segment may veto any matter brought before the Hearing Body after recusals.

    Each Regional Entity will notify NERC of all hearings and NERC may observe any of the proceedings. Each Regional Entity will notify NERC of the outcome of all hearings.

    If a Bulk Power System owner, operator, or user or a Regional Entity has

completed the Regional Entity hearing process and desires to appeal the outcome of the hearing, the Bulk Power System owner, operator, or user or the Regional Entity shall appeal to NERC in accordance with Section 409 of these Rules of Procedure, except that a determination of violation or Penalty that has been directly adjudicated by an Applicable Governmental Authority shall be appealed with that Applicable Governmental Authority.

16. **Annual Regional Entity Compliance Monitoring and Enforcement Program Implementation Plan** — Each Regional Entity shall annually develop and submit to NERC for approval a Regional Entity Compliance Monitoring and Enforcement Implementation Plan in accordance with **Appendix 4C** that, includes details on regional risk assessment processes and results, Reliability Standards and Requirements associated with regional risk assessment results, the methods to be used by the Regional Entity for reporting, monitoring, evaluating, and assessing performance criteria and the Regional Entity's Annual Audit Plan. These Regional Implementation Plans will be submitted to NERC on the schedule established by NERC, generally on or about October 1 of the preceding year. In conjunction with the annual Regional Implementation Plan, each Regional Entity must report to NERC regarding how it carried out its delegated compliance monitoring and enforcement authority in the previous year, the effectiveness of the Compliance Monitoring and Enforcement Program, and changes expected to correct any deficiencies identified. Each Regional Entity will provide its annual report on the schedule established by NERC, generally on or about February 15 of the following year.

404. NERC Monitoring of Compliance for Regional Entities or Bulk Power Owners, Operator, or Users

NERC shall monitor Regional Entity compliance with NERC Reliability Standards and, if no there is no delegation agreement in effect with a Regional Entity for the geographic area, shall monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards. Industry subject matter experts may be used as appropriate in Compliance Investigations, Compliance Audits, and other Compliance Monitoring and Enforcement Program activities, subject to confidentiality, antitrust, and conflict of interest provisions.

1. **NERC Obligations** — NERC Compliance Staff shall monitor the compliance of the Regional Entity with the Reliability Standards for which the Regional Entities are responsible, in accordance with **Appendix 4C**. NERC shall actively monitor in its annual Compliance Enforcement and Monitoring Program selected Reliability Standards that apply to the Regional Entities. NERC shall evaluate compliance and noncompliance with all of the Reliability Standards that apply to the Regional Entities and shall impose sanctions, Penalties, or Remedial Action Directives when there is a finding of noncompliance. NERC shall post all violations of Reliability Standards that apply to the Regional Entities as described in the reporting and disclosure process in **Appendix 4C**.

In addition, NERC will directly monitor Bulk Power System owners, operators, and users for compliance with NERC Reliability Standards in any geographic area for which there is not a delegation agreement in effect with a Regional Entity, in accordance with **Appendix 4C**. In such cases, NERC will serve as the Compliance Enforcement Authority described in **Appendix 4C**. Compliance matters contested by Bulk Power System owners, operators, and users in such an event will be heard by the NERC Compliance and Certification Committee.

2. **Compliance Audit of the Regional Entity** — NERC shall perform a Compliance Audit of each Regional Entity responsible for complying with Reliability Standards at least once every three years. NERC shall make an evaluation of compliance based on the information obtained through the Compliance Audit. After due process is complete, the final Compliance Audit report shall be made public in accordance with the reporting and disclosure process in **Appendix 4C**.

3. **Appeals Process** — Any Regional Entity or Bulk Power System owner, operator or user found by NERC, as opposed to a Regional Entity, to be in noncompliance with a Reliability Standard may appeal the findings of noncompliance with Reliability Standards and any sanctions or Remedial Action Directives that are issued by, or Mitigation Plan components imposed by, NERC, pursuant to the processes described in Sections 408 through 410.

405. Monitoring of Reliability Standards and Other Requirements Applicable to NERC

The NERC Compliance and Certification Committee shall establish and implement a process to monitor NERC's compliance with the Reliability Standards that apply to NERC. The process shall use independent monitors with no conflict of interest, real or perceived, in the outcomes of the process. All violations shall be made public according to the reporting and disclosure process in **Appendix 4C**. The Compliance and Certification Committee will also establish a procedure for monitoring NERC's compliance with its Rules of Procedure for the Standards Development, Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs. Such procedures shall not be used to circumvent the appeals processes established for those programs.

406. Independent Audits of the NERC Compliance Monitoring and Enforcement Program

NERC shall provide for an independent audit of its Compliance Monitoring and Enforcement Program at least once every three years, or more frequently as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board. The independent audit shall meet the following minimum requirements and any other requirements established by the NERC Board.

1. **Effectiveness** — The audit shall evaluate the success and effectiveness of the NERC Compliance Monitoring and Enforcement Program in achieving its mission.

2. **Relationship** — The audit shall evaluate the relationship between NERC and the Regional Entity Compliance Monitoring and Enforcement Programs and the effectiveness of the programs in ensuring reliability.

3. **Final Report Posting** — The final report shall be posted by NERC for public viewing in accordance with **Appendix 4C**.

4. **Response to Recommendations** — If the audit report includes recommendations to improve the NERC Compliance Monitoring and Enforcement Program, the administrators of the NERC Compliance Monitoring and Enforcement Program shall provide a written response and plan to the Board within 30 days of the release of the final audit report.

407. Penalties, Sanctions, and Remedial Action Directives

1. **NERC Review of Regional Entity Penalties and Sanctions —** NERC shall review all Penalties, sanctions, and Remedial Action Directives imposed by each Regional Entity for violations of Reliability Standards, including Penalties, sanctions and Remedial Action Directives that are specified by a Regional Entity Hearing Body final decision issued pursuant to Attachment 2 to **Appendix 4C**, to determine if the Regional Entity's determination is supported by a sufficient record compiled by the Regional Entity, is consistent with the *Sanction Guidelines* incorporated into these Rules of Procedure as **Appendix 4B** and with other directives, guidance and directions issued by NERC pursuant to the delegation agreement, and is consistent with Penalties, sanctions and Remedial Action Directives imposed by the Regional Entity and by other Regional Entities for violations involving the same or similar facts and circumstances.

2. **Developing Penalties and Sanctions** — The Regional Entity Compliance Staff shall use the *Sanction Guidelines*, which are incorporated into these Rules of Procedure as **Appendix 4B**, to develop an appropriate Penalty, sanction, or Remedial Action Directive for a violation, and shall notify NERC of the Penalty, sanction or Remedial Action Directive.

3. **Effective Date of Penalty** — Where authorized by applicable legislation or agreement, no Penalty imposed for a violation of a Reliability Standard shall take effect until the thirty-first day after NERC files, with the Applicable Governmental Authority, a "Notice of Penalty" and the record of the proceedings in which the violation and Penalty were determined, or such other date as ordered by the Applicable Governmental Authority.

408. Review of NERC Decisions

1. **Scope of Review** — A Registered Entity or a Regional Entity wishing to challenge a finding of noncompliance and the imposition of a Penalty for a compliance measure directly administered by NERC, or a Regional Entity wishing to challenge a Regional Entity Compliance Monitoring and Enforcement Program audit finding, may do so by filing a notice of the challenge with NERC's

director of enforcement no later than 21 days after issuance of the notice of finding of violation or audit finding. Appeals by Registered Entities or Regional Entities of decisions of Regional Entity Hearing Bodies shall be pursuant to Section 409.

2. **Contents of Notice** — The notice of challenge shall include the full text of the decision that is being challenged, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief.

3. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of challenge, the NERC director of enforcement may file with the Hearing Panel a response to the issues raised in the notice, with a copy to the Regional Entity.

4. **Hearing by Compliance and Certification Committee** — The NERC Compliance and Certification Committee shall provide representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program an opportunity to be heard and shall decide the matter based upon the filings and presentations made, with a written explanation of its decision.

5. **Appeal** — The Regional Entity or Registered Entity may appeal the decision of the Compliance and Certification Committee by filing a notice of appeal with NERC's director of enforcement no later than 21 days after issuance of the written decision by the Compliance and Certification Committee. The notice of appeal shall include the full text of the written decision of the Compliance and Certification Committee that is being appealed, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not presented to the Compliance and Certification Committee.

6. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of appeal, the NERC Compliance Monitoring and Enforcement Program staff may file its response to the issues raised in the notice of appeal, with a copy to the entity filing the notice.

7. **Reply** — The entity filing the appeal may file a reply within 7 days.

8. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record, the response, and any reply. At its discretion, the Compliance Committee may invite representatives of the Regional Entity or Registered Entity, and the NERC Compliance Monitoring and Enforcement Program to appear before the Compliance Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

9. **Impartiality** — No member of the Compliance and Certification Committee or the Board of Trustees Compliance Committee having an actual or perceived conflict of interest in the matter may participate in any aspect of the challenge or appeal except as a party or witness.

10. **Expenses** — Each party in the challenge and appeals processes shall pay its own expenses for each step in the process.

11. **Non-Public Proceedings —** All challenges and appeals shall be closed to the public to protect Confidential Information.

409. Appeals from Final Decisions of Regional Entity Hearing Bodies

1. **Time for Appeal** — A Regional Entity acting as the Compliance Enforcement Authority, or an owner, operator or user of the Bulk Power System, shall be entitled to appeal from a final decision of a Regional Entity Hearing Body concerning an Alleged Violation of a Reliability Standard, a proposed Penalty or sanction for violation of a Reliability Standard, a proposed Mitigation Plan, or a proposed Remedial Action Directive, by filing a notice of appeal with NERC's director of enforcement, with copies to the Regional Entity and any other Participants in the Regional Entity Hearing Body proceeding, no later than 21 days after issuance of the final decision of the Regional Entity Hearing Body.

2. **Contents** — The notice of appeal shall include the full text of the final decision of the Regional Entity Hearing Body that is being appealed, a concise statement of the error or errors contained in the final decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not first presented during the proceeding before the Regional Entity Hearing Body.

3. **Response to Notice of Appeal** — Within 21 days after the date the notice of appeal is filed, the Regional Entity shall file the entire record of the Regional Entity Hearing Body proceeding with NERC's director of enforcement, with a copy to the Participant filing the notice. Within 35 days after the date of the notice of appeal, all Participants in the proceeding before the Regional Entity Hearing Body, other than the Participant filing the notice of appeal, shall file their responses to the issues raised in the notice of appeal.

4. **Reply** — The Registered Entity filing the appeal may file a reply to the responses within 7 days.

5. **Decision** — The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record of the proceeding before the Regional Entity Hearing Body, the responses, and any reply filed with NERC. At its discretion, the Compliance Committee may invite representatives of the entity making the appeal and the other Participants in the proceeding before the Regional Entity Hearing Body to appear before the

Committee. Decisions of the Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

6. **Expenses** — Each party in the appeals process shall pay its own expenses for each step in the process.

7. **Non-Public Proceedings** — All appeals shall be closed to the public to protect Confidential Information.

8. **Appeal of Hearing Body Decisions Granting or Denying Motions to Intervene** — This section is not applicable to an appeal of a decision of a Regional Entity Hearing Body granting or denying a motion to intervene in the Regional Entity Hearing Body proceeding. Appeals of decisions of Regional Entity Hearing Bodies granting or denying motions to intervene in Regional Entity Hearing Body proceedings shall be processed and decided pursuant to Section 414.

410. Hold Harmless

A condition of invoking the challenge or appeals processes under Section 408 or 409 is that the entity requesting the challenge or appeal agrees that neither NERC (defined to include its Members, Board of Trustees, committees, subcommittees, staff and industry subject matter experts), any person assisting in the challenge or appeals processes, nor any company employing a person assisting in the challenge or appeals processes, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the challenge or appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards

A Registered Entity that is subject to an Applicable Requirement of a NERC Critical Infrastructure Protection Standard for which Technical Feasibility Exceptions are permitted, may request a Technical Feasibility Exception to the Requirement, and the request will be reviewed, approved or disapproved, and if approved, implemented, in accordance with the NERC *Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standard*, Appendix 4D to these Rules of Procedure.

412. Certification of Questions from Regional Entity Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee

1. A Regional Entity Hearing Body that is conducting a hearing concerning a disputed compliance matter pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, may certify to the Board of Trustees, for decision, a significant question of law, policy or procedure the resolution of which may be determinative of the issues in the hearing in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by

the Compliance Committee appropriate, in accordance with Section 1.5.12 of the Hearing Procedures. All questions certified by a Regional Entity Hearing Body to the Board of Trustees shall be considered and disposed of by the Compliance Committee.

2. The Compliance Committee may accept or reject a certification of a question for decision. If the Compliance Committee rejects the certified question, it shall issue a written statement that the certification is rejected.

3. If the Compliance Committee accepts the certification of a question for decision, it shall establish a schedule by which the Participants in the hearing before the Regional Entity Hearing Body may file memoranda and reply memoranda stating their positions as to how the question certified for decision should be decided by the Compliance Committee. The Compliance Committee may also request, or provide an opportunity for, the NERC compliance operations department, the NERC compliance enforcement department, and/or the NERC general counsel to file memoranda stating their positions as to how the question certified for decision should be decided. After receiving such memoranda and reply memoranda as are filed in accordance with the schedule, the Compliance Committee shall issue a written decision on the certified question.

4. Upon receiving the Compliance Committee's written decision on the certified question, the Regional Entity Hearing Body shall proceed to complete the hearing in accordance with the Compliance Committee's decision.

5. The Compliance Committee's decision, if any, on the certified question shall only be applicable to the hearing from which the question was certified and to the Participants in that hearing.

413. Review and Processing of Regional Entity Hearing Body Final Decisions that Are Not Appealed

NERC shall review and process all final decisions of Regional Entity Hearing Bodies issued pursuant to Attachment 2 to Appendix 4C concerning an Alleged Violation, proposed Penalty or sanction, or proposed Mitigation Plan that are not appealed pursuant to Section 409, as though the determination had been made by the Regional Entity Compliance Monitoring and Enforcement Program. NERC shall review and process such final decisions, and may require that they be modified by the Regional Entity, in accordance with, as applicable to the particular decision, Sections 5.8, 5.9 and 6.5 of Appendix 4C.

414. Appeals of Decisions of Regional Entity Hearing Bodies Granting or Denying Motions to Intervene in Regional Entity Hearing Body Proceedings

1. **Time to Appeal** — An entity may appeal a decision of a Regional Entity Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** denying the entity's motion to intervene in a Regional Entity Hearing Body proceeding, and the Regional Entity Compliance Staff or any other Participant in the Regional Entity

Hearing Body proceeding may appeal a decision of the Regional Entity Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** granting or denying a motion to intervene in the Regional Entity Hearing Body proceeding, in either case by filing a notice of appeal with the NERC director of enforcement, with copies to the Regional Entity Clerk, the Regional Entity Hearing body, the Hearing Officer, the Regional Entity Compliance Staff, and all other Participants in the Regional Entity Hearing Body proceeding, no later than seven (7) days following the date of the Regional Entity Hearing Body decision granting or denying the motion to intervene.

2. **Contents of Notice of Appeal** — The notice of appeal shall set forth information and argument to demonstrate that the decision of the Regional Entity Hearing Body granting or denying the motion to intervene was erroneous under the grounds for intervention specified in Section 1.4.4 of Attachment 2 of **Appendix 4C** and that the entity requesting intervention should be granted or denied intervention, as applicable. Facts alleged in, and any offers of proof made in, the notice of appeal shall be supported by affidavit or verification. The notice of appeal shall include a copy of the original motion to intervene and a copy of the decision of the Regional Entity Hearing Body granting or denying the motion to intervene.

3. **Responses to Notice of Appeal** — Within ten (10) days following the date the notice of appeal is filed, the Regional Entity Clerk shall transmit to the NERC director of enforcement copies of all pleadings filed in the Regional Entity Hearing Body proceeding on the motion to intervene. Within fourteen (14) days following the date the notice of appeal is filed, the Regional Entity Hearing Body, the Regional Entity Compliance Staff, and any other Participants in the Regional Entity Hearing Body proceeding, may each file a response to the notice of appeal with the NERC director of enforcement. Within seven (7) days following the last day for filing responses, the entity filing the notice of appeal, and any Participant in the Regional Entity Hearing Body proceeding that supports the appeal, may file replies to the responses with the NERC director of enforcement.

4. **Disposition of Appeal** — The appeal shall be considered and decided by the Compliance Committee. The NERC director of enforcement shall provide copies of the notice of appeal and any responses and replies to the Compliance Committee. The Compliance Committee shall issue a written decision on the appeal; provided, that if the Compliance Committee does not issue a written decision on the appeal within forty-five (45) days following the date of filing the notice of appeal, the appeal shall be deemed denied and the decision of the Regional Entity Hearing Body granting or denying the motion to intervene shall stand. The NERC director of enforcement shall transmit copies of the Compliance Committee's decision, or shall provide notice that the forty-five (45) day period has expired with no decision by the Compliance Committee, to the Regional Entity Clerk, the Regional Entity Hearing Body, the entity filing the notice of appeal, the Regional Entity Compliance Staff, and any other Participants

in the Regional Entity Hearing Body proceeding that filed responses to the notice of appeal or replies to responses.

5. **Appeal of Compliance Committee Decision to FERC or Other Applicable Governmental Authority** — Any entity aggrieved by the decision of the Compliance Committee on an appeal of a Regional Entity Hearing Body decision granting or denying a motion to intervene in a Regional Entity Hearing Body proceeding (including a denial of such appeal by the expiration of the forty-five (45) day period as provided in Section 414.4) may appeal or petition for review of the decision of the Compliance Committee to FERC or to another Applicable Governmental Authority having jurisdiction over the matter, in accordance with the authorities, rules and procedures of FERC or such other Applicable Governmental Authority. Any such appeal or petition for review shall be filed within the time period, if any, and in the form and manner, specified by the applicable statutes, rules or regulations governing proceedings before FERC or the other Applicable Governmental Authority.

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION

501. Scope of the Organization Registration and Organization Certification Programs

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards. Registered Entities are not and do not become Members of NERC or a Regional Entity, by virtue of being listed on the NCR. Membership in NERC is governed by Article II of NERC's Bylaws; membership in a Regional Entity or regional reliability organization is governed by that entity's bylaws or rules.

The purpose of the Organization Certification Program is to ensure that the new entity (i.e., applicant to be an RC, BA, or TOP that is not already performing the function for which it is applying to be certified as) has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational.

Organization Registration and Organization Certification may be delegated to Regional Entities in accordance with the procedures in this Section 500; the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into these Rules of Procedure as **Appendix 5A**; and, approved Regional Entity delegation agreements or other applicable agreements.

1. **NERC Compliance Registry** — NERC shall establish and maintain the NCR of the Bulk Power System owners, operators, and users that are subject to approved Reliability Standards.

   1.1 (a) The NCR shall set forth the identity and functions performed for each organization responsible for meeting Requirements/sub-Requirements of the Reliability Standards. Bulk Power System owners, operators, and users (i) shall provide to NERC and the applicable Regional Entity information necessary to complete the Registration, and (ii) shall provide NERC and the applicable Regional Entity with timely updates to information concerning the Registered Entity's ownership, operations, contact information, and other information that may affect the Registered Entity's Registration status or other information recorded in the Compliance Registry.

   (b) A generation or transmission cooperative, a joint-action agency or another organization may register as a Joint Registration Organization (JRO), in lieu of each of the JRO's members or related entities being registered individually for one or more functions. Refer to Section 507.

(c) Multiple entities may each register using a Coordinated Functional Registration (CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility. Refer to Section 508.

1.2 In the development of the NCR, NERC and the Regional Entities shall determine which organizations should be placed on the NCR based on the criteria provided in the NERC *Statement of Compliance Registry Criteria* which is incorporated into these Rules of Procedure as **Appendix 5B**.

1.3 NERC and the Regional Entities shall use the following rules for establishing and maintaining the NCR based on the Registration criteria as set forth in **Appendix 5B** *Statement of Compliance Registry Criteria*:

1.3.1 NERC shall notify each organization that it is on the NCR. The Registered Entity is responsible for compliance with all the Reliability Standards applicable to the functions for which it is registered from the time it receives the Registration notification from NERC.

1.3.2 Any organization receiving such a notice may challenge its placement on the NCR according to the process in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section V.

1.3.3 The Compliance Committee of the Board of Trustees shall promptly issue a written decision on the challenge, including the reasons for the decision.

1.3.4 The decision of the Compliance Committee of the Board of Trustees shall be final unless, within 21 days of the date of the Compliance Committee of the Board of Trustees decision, the organization appeals the decision to the Applicable Governmental Authority.

1.3.5 Each Registered Entity identified on the NCR shall notify its corresponding Regional Entity(s) of any corrections, revisions, deletions, changes in ownership, corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards. Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards applicable to its associated Registration.

1.4 For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall:

1.4.1 Ensure that all areas are under the oversight of one and only one Reliability Coordinator.

1.4.2 Ensure that all Balancing Authorities and Transmission Operator entities[2] are under the responsibility of one and only one Reliability Coordinator.

1.4.3 Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator.

1.4.4 Ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority.

1.5 NERC shall maintain the NCR of organizations responsible for meeting the Requirements/sub-Requirements of the Reliability Standards currently in effect on its website and shall update the NCR monthly.

1.6 With respect to: (i) entities to be registered for the first time; (ii) currently-registered entities or (iii) previously-registered entities, for which registration status changes are sought, including availability and composition of a sub-set list of applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements), the registration process steps in Section III of **Appendix 5A** apply.

1.7 NERC shall establish a NERC-led, centralized review panel, comprised of a NERC lead with Regional Entity participants, in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III.D and **Appendix 5B**, *Statement of Compliance Registry Criteria*.

2. **Entity Certification** — NERC shall provide for Certification of all entities with primary reliability responsibilities requiring Certification. This includes those

[2] Some organizations perform the listed functions (e.g., Balancing Authority, Transmission Operator) over areas that transcend the Footprints of more than one Reliability Coordinator. Such organizations will have multiple Registrations, with each such Registration corresponding to that portion of the organization's overall area that is within the Footprint of a particular Reliability Coordinator.

entities that satisfy the criteria established in the NERC provisional Certification process. The NERC programs shall:

2.1 Evaluate and certify the competency of entities performing reliability functions. The entities presently expected to be certified include Reliability Coordinators, Transmission Operators, and Balancing Authorities.

2.2 Evaluate and certify each applicant's ability to meet the requirements for Certification.

2.3 Maintain process documentation.

2.4 Maintain records of currently certified entities.

2.5 Issue a Certification document to the applicant that successfully demonstrates its competency to perform the evaluated functions.

3. **Delegation and Oversight**

3.1 NERC may delegate responsibilities for Organization Registration and Organization Certification to Regional Entities in accordance with requirements established by NERC. Delegation will be via the delegation agreement between NERC and the Regional Entity or other applicable agreement. The Regional Entity shall administer Organization Registration and Organization Certification Programs in accordance with such delegations to meet NERC's programs goals and requirements subject to NERC oversight.

3.2 NERC shall develop and maintain a plan to ensure the continuity of Organization Registration and Organization Certification within the geographic or electrical boundaries of a Regional Entity in the event that no entity is functioning as a Regional Entity for that Region, or the Regional Entity withdraws as a Regional Entity, or does not operate its Organization Registration and Organization Certification Programs in accordance with delegation agreements.

3.3 NERC shall develop and maintain a program to monitor and oversee the NERC Organization Registration and Organization Certification Programs activities that are delegated to each Regional Entity through a delegation agreement or other applicable agreement.

3.3.1 This program shall monitor whether the Regional Entity carries out those delegated activities in accordance with NERC requirements, and whether there is consistency, fairness of administration, and comparability.

3.3.2 Monitoring and oversight shall be accomplished through direct participation in the Organization Registration and Organization Certification Programs with periodic reviews of documents and records of both programs.

502. Organization Registration and Organization Certification Program Requirements

1. NERC shall maintain the Organization Registration and Organization Certification Programs.

   1.1 The roles and authority of Regional Entities in the programs are delegated from NERC pursuant to the Rules of Procedure through regional delegation agreements or other applicable agreements.

   1.2 Processes for the programs shall be administered by NERC and the Regional Entities. Materials that each Regional Entity uses are subject to review and approval by NERC.

   1.3 The appeals process for the Organization Registration and Organization Certification Programs are identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Sections V and VI, respectively.

   1.4 The Certification Team membership is identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section IV.8.d.

2. To ensure consistency and fairness of the Organization Registration and Organization Certification Programs, NERC shall develop procedures to be used by all Regional Entities and NERC in accordance with the following criteria:

   2.1 NERC and the Regional Entities shall have data management processes and procedures that provide for confidentiality, integrity, and retention of data and information collected.

   2.2 Documentation used to substantiate the conclusions of the Regional Entity/ NERC related to Registration and/or Certification must be retained by the Regional Entity for (6) six years, unless a different retention period is otherwise identified, for the purposes of future audits of these programs.

   2.3 To maintain the integrity of the NERC Organization Registration and Organization Certification Programs, NERC, Regional Entities, Certification Team members, program audit team members (Section 506), and committee members shall maintain the confidentiality of information provided by an applicant or entities.

      2.2.1 NERC and the Regional Entities shall have appropriate codes of conduct and confidentiality agreements for staff, Certification

Team, Certification related committees, and Certification program audit team members.

2.2.2 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall maintain the confidentiality of any Registration or Certification-related discussions or documents designated as confidential (see Section 1500 for types of Confidential Information).

2.2.3 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall treat as confidential the individual comments expressed during evaluations, program audits and report-drafting sessions.

2.2.4 Copies of notes, draft reports, and other interim documents developed or used during an entity Certification evaluation or program audit shall be destroyed after the public posting of a final, uncontested report.

2.2.5 Information deemed by an applicant, entity, a Regional Entity, or NERC as confidential, including Critical Energy Infrastructure Information, shall not be released publicly or distributed outside of a committee or team.

2.2.6 In the event that an individual violates any of the confidentiality rules set forth above, that individual and any member organization with which the individual is associated will be subject to immediate dismissal from the audit team and may be prohibited from future participation in Compliance Monitoring and Enforcement Program activities by the Regional Entity or NERC.

2.2.7 NERC shall develop and provide training in auditing skills to all individuals prior to their participation in Certification evaluations. Training for Certification Team leaders shall be more comprehensive than the training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

2.4 An applicant that is determined to be competent to perform a function after completing all Certification requirements shall be deemed certified by NERC to perform that function for which it has demonstrated full competency.

2.4.1 All NERC certified entities shall be included on the NCR.

503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements

1. **Delegation** — Recognizing the Regional Entity's knowledge of and experience with their members, NERC may delegate responsibility for Organization Registration and Organization Certification to the Regional Entity through a delegation agreement.

2. **Registration** — The following Organization Registration activities shall be managed by the Regional Entity per the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into the Rules of Procedure as Appendix 5A *Organization Registration and Organization Certification Manual*:

   2.1 Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4).

3. **Certification —** The following Organization Certification activities shall be managed by the Regional Entity in accordance with an approved delegation agreement or another applicable agreement:

   3.1 An entity seeking Certification to perform one of the functions requiring Certification shall contact the Regional Entity for the Region(s) in which it plans to operate to apply for Certification.

   3.2 An entity seeking Certification and other affected entities shall provide all information and data requested by NERC or the Regional Entity to conduct the Certification process.

   3.3 Regional Entities shall notify NERC of all Certification applicants.

   3.4 NERC and/or the Regional Entity shall evaluate the competency of entities requiring Certification to meet the NERC Certification requirements.

   3.5 NERC or the Regional Entity shall establish Certification procedures to include evaluation processes, schedules and deadlines, expectations of the applicants and all entities participating in the evaluation and Certification processes, and requirements for Certification Team members.

      3.5.1 The NERC / Regional Entity Certification procedures will include provisions for on-site visits to the applicant's facilities to review the data collected through questionnaires, interviewing the operations and management personnel, inspecting the facilities and equipment (including requesting a demonstration of all tools identified in the Certification process), reviewing all necessary documents and data (including all agreements, processes, and procedures identified in the Certification process), reviewing

Certification documents and projected system operator work schedules, and reviewing any additional documentation needed to support the completed questionnaire or inquiries arising during the site visit.

3.5.2 The NERC/ Regional Entity Certification procedures will provide for preparation of a written report by the Certification Team, detailing any deficiencies that must be resolved prior to granting Certification, along with any other recommendations for consideration by the applicant, the Regional Entity, or NERC.

504. Appeals

1. NERC shall maintain an appeals process to resolve any disputes related to Registration or Certification activities per the *Organization Registration and Organization Certification Manual*, which is incorporated in these Rules of Procedure as Appendix 5A.

2. The Regional Entity Certification appeals process shall culminate with the Regional Entity board or a committee established by and reporting to the Regional Entity board as the final adjudicator, provided that where applicable, Canadian provincial governmental authorities may act as the final adjudicator in their jurisdictions. NERC shall be notified of all appeals and may observe any proceedings **(Appendix 5A** *Organization Registration and Organization Certification Manual*).

505. Program Maintenance

NERC shall maintain its program materials, including such manuals or other documents as it deems necessary, of the governing policies and procedures of the Organization Registration and Organization Certification Programs.

506. Independent Audit of NERC Organization Registration and Organization Certification Program

1. NERC, through the Compliance and Certification Committee, shall provide for an independent audit of its Organization Registration and Organization Certification Programs at least once every three years, or more frequently, as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board.

2. The audit shall evaluate the success, effectiveness and consistency of the NERC Organization Registration and Organization Certification Programs.

3. The final report shall be posted by NERC for public viewing.

4. If the audit report includes recommendations to improve the program, the administrators of the program shall provide a written response to the Board within 30 days of the final report, detailing the disposition of each and every

recommendation, including an explanation of the reasons for rejecting a recommendation and an implementation plan for the recommendations accepted.

507. Provisions Relating to Joint Registration Organizations (JRO)

1. In addition to registering as the entity responsible for all functions that it performs itself, an entity may register as a JRO on behalf of one or more of its members or related entities for one or more functions for which such members or related entities would otherwise be required to register and, thereby, accept on behalf of such members or related entities all compliance responsibility for that function or those functions including all reporting requirements. Any entity seeking to register as a JRO must submit a written agreement with its members or related entities for all Requirements/sub-Requirements for the function(s) for which the entity is registering for and takes responsibility for, which would otherwise be the responsibility of one or more of its members or related entities. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the JRO Registration.

2. The JRO Registration data must include the same Registration information as a normal compliance Registration entry. The JRO is responsible for providing all of the information and data, including submitting reports, as needed by the Regional Entity for performing assessments of compliance.

3. The Regional Entity shall notify NERC of each JRO that the Regional Entity accepts. The notification will identify the point of contact and the functions(s) being registered for on behalf of its members or related entities.

4. For purposes of Compliance Audits, the Regional Entity shall keep a list of all JROs. This document shall contain a list of each JRO's members or related entities and the function(s) for which the JRO is registered for that member(s) or related entity(s). It is the responsibility of the JRO to provide the Regional Entity with this information as well as the applicable JRO agreement(s).

5. The Regional Entity may request clarification of any list submitted to it that identifies the members of the JRO and may request such additional information as the Regional Entity deems appropriate.

6. The Regional Entity's acceptance of a JRO shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the JRO will meet the Registration requirements of Section 501(1.4).

7. NERC shall maintain, and post on its website, a JRO registry listing all JRO Registrations that have been reviewed and accepted by the Regional Entity. The posting shall identify the JRO entity taking compliance responsibilities for itself and its members.

8. The JRO shall inform the Regional Entity of any changes to an existing JRO. The Regional Entity shall promptly notify NERC of each such revision.

9. Nothing in Section 507 shall preclude a member of a JRO, a related entity, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the member or other entity is registering. A JRO member or related entity that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the JRO of its Registration.

508. Provisions Relating to Coordinated Functional Registration (CFR) Entities

1. In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.

2. Each CFR or each individual entity within a CFR must identify a point of contact that is responsible for providing information and data, including submitting reports as needed by the Regional Entity related to the CFR Registration.

3. The Regional Entity shall notify NERC of each CFR that the Regional Entity accepts.

4. NERC or the Regional Entity may request clarification of any list submitted to it that identifies the compliance responsibilities of the CFR and may request such additional information as NERC or the Regional Entity deems appropriate.

5. The Regional Entity's acceptance of that CFR shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded the CFR will meet the Registration requirements of Section 501(1.4).

6. NERC shall maintain, and post on its website, a CFR registry listing all CFR Registrations that have been accepted by NERC or by a Regional Entity. The posting shall clearly list all the Reliability Standards or Requirements/sub-Requirements thereof for which each entity of the CFR is responsible for under the CFR.

7. The point of contact shall inform the Regional Entity of any changes to an existing CFR. The Regional Entity shall promptly notify NERC of each such revision.

8. In the event of a violation of a Reliability Standard or of a Requirement/sub-Requirement of a Reliability Standard for which an entity of a CFR is registered, that entity shall be identified in the Notice of Alleged Violation and shall be assessed the sanction or Penalty in accordance with the NERC Sanctions Guidelines. In the event a Regional Entity is not able to determine which entity(ies) is responsible for a particular Reliability Standard, or Requirements/sub-Requirements thereof that has been violated, the Regional Entity shall investigate the noncompliance in accordance with the NERC Rules of Procedure Section 400, *Compliance Enforcement*, to determine the entity(ies) to which the Regional Entity shall to issue the sanction or Penalty for the violation.

9. Nothing in Section 508 shall preclude an entity registered in a CFR, or any other entity from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards applicable to the function(s) for which the entity is registering. An entity registered in a CFR that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the point of contact of its Registration.

509. Exceptions to the Definition of the Bulk Electric System

An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered part of the Bulk Electric System.

SECTION 600 — PERSONNEL CERTIFICATION

601. Scope of Personnel Certification Program

Maintaining the reliability of the Bulk ~~Electric~~ Power System through implementation of the Reliability Standards requires skilled ~~, trained~~ and qualified personnel, including system operators. NERC shall develop a ~~The~~ Personnel Certification Program ~~provides~~ to:

1. Provide the mechanism to determine system operators' ~~ensure system operators are provided the education and training necessary to obtain the essential knowledge and skills and are therefore qualified to operate the Bulk Electric System. The Personnel Certification awards system operator Certification Credentials to individuals who demonstrate that they have attained~~ essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations~~;~~.

2. administer a system operator Certification exam; and

3. award the system operator Certification Credential to individuals who pass the exam.

The NERC Personnel Certification Program shall be international in scope consistent with the ERO's international regulatory responsibility for ~~NERC, as~~ the reliability of the Bulk Power System in North America.

NERC Reliability Standards define which ~~ERO, will ensure skilled, trained, and qualified~~ system operators require certification pursuant to the NERC ~~through the~~ Personnel Certification Program.

The ~~Except as necessary to obtain approval of the Rules of Procedure, the~~ NERC Personnel Certification Governance Committee (PCGC) is the governing body that establishes the policies, sets fees, and monitors the performance of the Personnel Certification Program for system operators.

602. Structure of ERO Personnel Certification Program

~~1. The NERC Personnel Certification Program shall be international in scope.~~

~~2. The PCGC shall (1) be able to independently exercise decision-making for all matters pertaining to Certification, (2) include individuals from the discipline being certified and whose composition addresses the needs of the users of the program (e.g., employers, regulators, etc.), and (3) have representation for each specialty or level within a discipline.~~

~~3. NERC shall maintain a nominating process for membership in the governing body. Nominations shall be open to all interested parties and self-nominations shall be accepted. The NERC Board of Trustees shall appoint members to the~~

~~governing body from among those nominated. The members of the governing body shall serve at the pleasure of the Board.~~

~~4. The PCGC shall have control over the matters related to the Personnel Certification and re-Certification Programs listed below, without being subject to approval by any other body.~~

~~Policies and procedures, including eligibility~~ The PCGC shall develop and update, as necessary, a manual which describes the following:

1. requirements ~~and application processing.~~for administering the system operator examinations;

2. requirements for exam eligibility;

3. requirements for awarding the Certification Credential;

4. requirements for Certification Credential maintenance;

5. dispute resolution procedures; and

~~4.1~~6. displicinary action guidelines.

~~4.2 Requirements for personnel Certification, maintaining Certification, and re-Certification.~~

~~4.3 Examination content, development, and administration.~~

~~4.4 Examination cut score.~~

~~4.5 Grievance and disciplinary processes.~~

~~4.6 Governing body and subgroup(s)' meeting rules including agenda, frequency, and related procedures.~~

~~4.7 Subgroup(s) appointments and work assignments.~~

~~4.8 Publications about personnel Certification and re-Certification.~~

~~4.9 Setting fees for application, and all other services provided as a part of the personnel Certification and re-Certification activities.~~

~~4.10 Program funding, spending, and budget authority. Financial matters related to the operation of the program shall be segregated from other NERC activities.~~

~~5. The Personnel Certification Program shall utilize written procedures for the selection of members of the governing body that prohibit the governing body from selecting a majority of its successors.~~

6. The Personnel Certification Program shall be separate from the accreditation and education functions of NERC in related disciplines.

7. No member of the PCGC or staff member working with the Personnel Certification Program governing body shall have or exercise any authority or responsibility for compliance matters related to Reliability Standards concerning personnel Certification.

603. Examination and Maintenance of NERC System Operator Certification Credentials[Placeholder]

1. System operators seeking to obtain a Credential must pass an examination to earn the Credential.

2. A certificate will be issued to successful candidates which is valid for three years.

3. A system operator must earn Continuing Education Hours (CE Hours) in NERC-Approved Learning Activities within the three-year period preceding the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual. A system operator must request a renewal and submit the appropriate fee for Certification renewal evaluation.

4. The Credential of a certified system operator who does not accumulate the required number and balance of CE Hours within the three-year period will be Suspended. A system operator with a Suspended certificate cannot perform any task that requires an operator to be NERC-certified. The system operator with a Suspended Credential will have up to twelve months to acquire the necessary CE Hours.

   4.1 During the time of suspension, the original anniversary date will be maintained. Therefore, should the system operator accumulate the required number of CE Hours within the twelve month suspension period, he/she will be issued a certificate that will be valid for three years from the previous expiration date.

   4.2 At the end of the twelve-month suspension period, if the system operator has not accumulated the required number of CE Hours, the Credential will be Revoked and all CE Hours earned will be forfeited. After a Credential is Revoked, the system operator will be required to pass an examination to become certified.

5. Hardship: Due to unforeseen events and extenuating circumstances, a certified system operator may be unable to accumulate the necessary CE Hours in the time frame required by the Personnel Certification Program to maintain the Credential. In such an event, the individual must submit a written request containing a thorough explanation of the circumstances and supporting information to the NERC Personnel Certification Manager. The PCGC retains the right to invoke

~~this hardship clause as it deems appropriate to address such events or circumstances.~~

604. Dispute Resolution Process

~~1.~~ Any dispute arising under ~~the NERC agreement establishing the *NERC Personnel Certification Program*~~this Section or ~~from the establishment of~~ any NERC rules, policies, or procedures dealing with any segment of the Certification process shall be subject to the NERC System Operator Certification Dispute Resolution Process in the manual. ~~The Dispute Resolution Process is for the use of persons who hold an operator Certification or persons wishing to be certified to dispute the validity of the examination, the content of the test, the content outlines, or the Registration process.~~

~~2. Dispute Resolution Process consists of three steps.~~

~~2.1. Notify NERC Personnel Certification Program Staff: This first step can usually resolve the issues without further actions. It is expected that most disputes will be resolved at this step. If the issue(s) is not resolved to the satisfaction of the parties involved in the first step, the issue can be brought to the PCGC Dispute Resolution Task Force.~~

~~2.2. PCGC Dispute Resolution Task Force: If the NERC staff did not resolve the issue(s) to the satisfaction of the parties involved, a written request must be submitted to the chairman of the PCGC through NERC staff explaining the issue(s) and requesting further action. Upon receipt of the letter, the PCGC chairman will present the request to the PCGC Dispute Resolution Task Force for action. This task force consists of three current members of the PCGC. The PCGC Dispute Resolution Task Force will investigate and consider the issue(s) presented and make a decision. This decision will then be communicated to the submitting party, the PCGC chairman, and the NERC staff within 45 calendar days of receipt of the request.~~

~~3. Personnel Certification Governance Committee: If the PCGC Dispute Resolution Task Force's decision did not resolve the issue(s) to the satisfaction of the parties involved, the final step in the process is for the issue(s) to be brought before the PCGC. Within 45 days of the date of the Task Force's decision, the disputing party shall submit a written request to the PCGC chairman through NERC staff requesting that the issue(s) be brought before the PCGC for resolution. The chairman shall see that the necessary documents and related data are provided to the PCGC members as soon as practicable. The PCGC will then meet or conference to discuss the issue(s) and make their decision within 60 calendar days of the chairman's receipt of the request. The decision will be provided to the person bringing the issue(s) and the NERC staff. The PCGC is the governing body of the Certification program and its decision is final.~~

4. Dispute Resolution Process Expenses: All individual expenses associated with the Dispute Resolution Process, including salaries, meetings, or consultant fees, shall be the responsibility of the individual parties incurring the expense.

5. Decision Process: Robert's Rules of Order shall be used as a standard of conduct for the Dispute Resolution Process. A majority vote of the members present will decide all issues. The vote will be taken in a closed session. No member of the PCGC may participate in the Dispute Resolution Process, other than as a party or witness, if he or she has an interest in the particular matter.

5.1 A stipulation of invoking the Dispute Resolution Process is that the entity invoking the Dispute Resolution Process agrees that neither NERC (its members, Board of Trustees, committees, subcommittees, and staff), any person assisting in the Dispute Resolution Process, nor any company employing a person assisting in the Dispute Resolution Process, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the Dispute Resolution Process. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

605. Disciplinary Action

1. Disciplinary action may be necessary to protect the integrity of the system operator Credential. The PCGC may initiate disciplinary action should an individual act in a manner that is inconsistent with expectations, including but not limited to:

1.1. Willful, gross, and/or repeated violation of the NERC Reliability Standards as determined by a NERC investigation.

1.2. Willful, gross, and/or repeated negligence in performing the duties of a certified system operator as determined by a NERC investigation.

1.3. Intentional misrepresentation of information provided on a NERC application for a system operator Certification exam or to maintain a system operator Credential using CE Hours.

1.4. Intentional misrepresentation of identification in the exam process, including a person identifying himself or herself as another person to obtain Certification for the other person.

1.5. Any form of cheating during a Certification exam, including, but not limited to, bringing unauthorized reference material in the form of notes, crib sheets, or other methods of cheating into the testing center.

1.6. A certified system operator's admission to or conviction of any felony or misdemeanor directly related to his/her duties as a system operator.

2. Hearing Process: Upon report to NERC of a candidate's or certified system operator's alleged misconduct, the NERC PCGC Credential Review Task Force will convene for the determination of facts. An individual, government agency, or other investigating authority can file a report. Unless the Task Force initially determines that the report of alleged misconduct is without merit, the candidate or certified system operator will be given the right to notice of the allegation. A hearing will be held and the charged candidate or certified system operator will be given an opportunity to be heard and present further relevant information. The Task Force may seek out information from other involved parties. The hearing will not be open to the public, but it will be open to the charged candidate or certified system operator and his or her representative. The Task Force will deliberate in a closed session, but the Task Force cannot receive any evidence during the closed session that was not developed during the course of the hearing.

3. Task Force's decision: The Task Force's decision will be unanimous and will be in writing with inclusion of the facts and reasons for the decision. The Task Force's written decision will be delivered to the PCGC and by certified post to the charged candidate or certified system operator. In the event that the Task Force is unable to reach a unanimous decision, the matter shall be brought to the full committee for a decision.

3.1. No Action: Allegation of misconduct was determined to be unsubstantiated or inconsequential to the Credential.

3.2. Probation: A letter will be sent from NERC to the offender specifying:

3.2.1. The length of time of the probationary period (to be determined by the PCGC).

3.2.2. Credential will remain valid during the probationary period.

3.2.3. The probationary period does not affect the expiration date of the current certificate.

3.2.4. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

3.3. Revoke for Cause: A letter will be sent from NERC to the offender specifying:

3.3.1. The length of time of the probationary period (to be determined by the PCGC).

3.3.2. Credential is no longer valid.

~~3.3.3. Successfully passing an exam will be required to become recertified.~~

~~3.3.4. An exam will not be authorized until the revocation period expires~~

~~3.4. Termination of Credential: A letter will be sent from NERC to the offender specifying permanent removal of Credential.~~

~~4. Credential Review Task Force: The Credential Review Task Force shall be comprised of three active members of the PCGC assigned by the Chairman of the PCGC on an ad hoc basis. No one on the Credential Review Task Force may have an interest in the particular matter. The Task Force will meet in a venue determined by the Task Force chairman.~~

~~5.~~ NERC rules, policies, or procedures dealing with any segment of the Certification process shall be subject to ~~Appeal Process: The decision of the Task Force may be appealed using~~ the NERC System Operator Certification Disciplinary Action ~~Dispute Resolution~~ Process in the manual.

606. Candidate Testing ~~Mechanisms~~

1. The ~~Personnel Certification Program~~PCGC shall ~~utilize reliable testing mechanisms~~develop exams to evaluate individual competence in a manner that is objective, and fair to all candidates, ~~job-related,~~ and to determine essential ~~based on the~~ knowledge ~~and skill needed to function in the discipline~~relating to NERC Reliability Standards as well as principles of the Bulk Power System operations.

2. The ~~Personnel Certification Program~~PCGC shall oversee exam administration as follows:

   2.1 A~~a~~dopt and implement a formal policy of periodic review of ~~the testing mechanisms~~exams ~~-~~to ~~ensure~~ access ongoing relevance ~~of the mechanisms~~ to knowledge and skill needed in the discipline; and

   ~~2.~~2.2 C~~c~~onduct ongoing studies to ~~substatntiate~~substantiate the reliability and validity of exams.~~.~~

3. The ~~Personnel Certification Program~~PCGC shall develop and utilize policies and procedures to ensure the integrity and security of exams and the transparency of ~~that all~~ test administration~~-~~ consistent with the~~w~~ following:~~and development materials are secure and demonstrate that these policies and procedures are consistently implemented.~~

   ~~4.~~3.1 The ~~Personnel Certification Program~~PCGC shall establish pass/fail levels that protect the public with a method that is based on competence and generally accepted standards in the psychometric community as being fair and reasonable;~~.~~

~~5.~~3.2 The ~~Personnel Certification Program~~PCGC shall conduct ongoing studies to substantiate the reliability and validity of the ~~testing mechanisms.~~exams;

~~6.~~3.3 The ~~Personnel Certification Program~~PCGC shall ~~utilize policies and procedures that govern~~dictate how long examination records are kept in their original format; and~~.~~

~~7.~~3.4 The ~~Personnel Certification Program~~PCGC shall demonstrate that different ~~forms~~ revisions of the ~~testing mechanisms~~exams assess equivalent content ~~and that candidates are not penalized for taking forms of varying difficulty~~.

607. Public Information About the Personnel Certification Program

~~1. The Personnel Certification Program shall maintain and publish publicly a System Operator Certification Program Manual describing the procedures used in examination construction and validation; all eligibility requirements and determination; fees; and examination administration documents, including: reporting of results, re-Certification requirements, and disciplinary and dispute resolution.~~

The ~~Personnel Certification Program~~PCGC shall maintain and publish the following:

~~2.~~1. a ~~publicly a comprehensive~~ summary ~~or outline~~ of the information, knowledge, or functions covered by each examination administered pursuant to the Personnel Certification Program; and.

~~3.~~2. ~~The Personnel Certification Program shall publish publicly and make available at least annually a~~an annual summary of Certification activities for the Personnel Certification Program~~program~~, including, ~~at least~~ the ~~following information:~~ number of examinations delivered, the number of applicants who passed, the number of applicants who failed, and the number ~~certified~~of applicants certified.

608. Responsibilities to Applicants for Certification or Re-Certification

The ~~Personnel Certification Program:~~PCGC

~~1.~~ s~~S~~hall ~~not discriminate among~~adhere to the following with respect to personnel ~~certifications~~ applicants: ~~as to age, gender, race, religion, national origin, disability, or marital status and shall include a statement of non-discrimination in announcements of the program.~~

~~2.~~1. ~~Shall~~ comply with all requirements of applicable federal and state/provincial laws with respect to all Certification and re-Certification activities, and shall require compliance of all contractors and/or providers of services;~~.~~

~~3.~~2. ~~Shall~~ make available to all applicants copies of formalized procedures for application for, and attainment of, personnel Certification and re-Certification and shall uniformly follow and enforce such procedures for all applicants;~~.~~

~~4.~~3. ~~Shall~~ implement a formal policy for the periodic review of eligibility criteria and application procedures for fairness; ~~to ensure that they are fair and equitable.~~

~~5.~~4. ~~Shall~~ provide competently proctored examination sites; and~~.~~

~~6. Shall~~ uniformly ~~report~~ provide applicants with examination results ~~to applicants in a timely manner.~~and

~~7.~~5. ~~Shall~~ give ~~applicants failing the examination information on general~~ content ~~areas of deficiency~~summary after the examination.

609. Responsibilities ~~to the Public and to~~ Employers of Certified ~~Practitioners~~Personnel

The ~~Personnel Certification Program~~PCGC shall adhere to the following with respect to certified personnel:

1. ~~Shall~~ demonstrate that the ~~testing mechanisms~~exams adequately measure ~~the~~ essential knowledge ~~and skill required for entry, maintenance, and/or advancement in the profession for each position~~relating to ~~be certified~~NERC Reliability Standards as well as principles of Bulk Power System operations;~~.~~

2. ~~Shall~~ award Certification and re-Certification only after the skill and knowledge of the individual have been evaluated and determined to be acceptable;~~.~~

3. ~~Shall~~ maintain, in an electronic format, a current list of those ~~persons~~ personnel certified in the programs and have policies and procedures that delineate what information about a Certification Credential holder may be made public and under what circumstances; and~~.~~

4. ~~Shall have~~develop ~~-~~formal policies and procedures for discipline of a Certification Credential holder, including the revocation of the certificate, for conduct deemed harmful to the public or inappropriate to the discipline (e.g., incompetence, unethical behavior, physical or mental impairment affecting performance). These procedures shall incorporate due process.

~~5. Shall demonstrate that any title or Credential awarded accurately reflects or applies to the practitioner's daily occupational or professional duties and is not confusing to employers, consumers, regulators, related professions, and/or other interested parties.~~

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members

1. All information made available or created during the course of any reliability readiness evaluation including, but not limited to, data, Documents, observations and notes, shall be maintained as confidential by all evaluation team members, in accordance with the requirements of Section 1500.

2. Evaluation team members are obligated to destroy all confidential evaluation notes following the posting of the final report of the reliability readiness evaluation.

3. NERC will retain reliability readiness evaluation-related documentation, notes, and materials for a period of time as defined by NERC.

4. These confidentiality requirements shall survive the termination of the NERC Reliability Readiness Evaluation and Improvement Program.

702. Formation of Sector Forum

1. NERC will form a sector forum at the request of any five members of NERC that share a common interest in the safety and reliability of the Bulk Power System. The members of sector forum may invite such others of the members of NERC to join the sector forum as the sector forum deems appropriate.

2. The request to form a sector forum must include a proposed charter for the sector forum. The Board must approve the charter.

3. NERC will provide notification of the formation of a sector forum to its membership roster. Notices and agendas of meetings shall be posted on NERC's website.

4. A sector forum may make recommendations to any of the NERC committees and may submit a Standards Authorization Request to the NERC *Reliability Standards Development Procedure*.

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS

801. Objectives of the Reliability Assessment and Performance Analysis Program

The objectives of the NERC Reliability Assessment and Performance Analysis Program are to: (1) conduct, and report the results of, an independent assessment of the overall reliability and adequacy of the interconnected North American Bulk Power Systems, both as existing and as planned; (2) analyze off-normal events on the Bulk Power System; (3) identify the root causes of events that may be precursors of potentially more serious events; (4) assess past reliability performance for lessons learned; (5) disseminate findings and lessons learned to the electric industry to improve reliability performance; and (6) develop reliability performance benchmarks. The final reliability assessment reports shall be approved by the Board for publication to the electric industry and the general public.

802. Scope of the Reliability Assessment Program

1. The scope of the Reliability Assessment Program shall include:

    1.1 Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.

    1.2 Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.

    1.3 Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.

    1.4 Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.

    1.5 Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.

2. The Reliability Assessment Program shall be performed in a manner consistent with the Reliability Standards of NERC including but not limited to those that specify reliability assessment Requirements.

803. Reliability Assessment Reports

The number and type of periodic assessments that are to be conducted shall be at the discretion of NERC. The results of the reliability assessments shall be documented in three reports: the long-term and the annual seasonal (summer) and the annual seasonal (winter) assessment reports. NERC shall also conduct special reliability assessments from time to time as circumstances warrant. The reliability assessment reports shall be reviewed and approved for publication by the Board. The three regular reports are described below.

1. **Long-Term Reliability Assessment Report** — The annual long-term report shall cover a ten-year planning horizon. The planning horizon of the long-term reliability assessment report shall be subject to change at the discretion of NERC. Detailed generation and transmission adequacy assessments shall be conducted for the first five years of the review period. For the second five years of the review period, the assessment shall focus on the identification, analysis, and projection of trends in peak demand, electric supply, and transmission adequacy, as well as other industry trends and developments that may impact future electric system reliability. Reliability issues of concern and their potential impacts shall be presented along with any mitigation plans or alternatives. The long-term reliability assessment reports will generally be published in the fall (September) of each year. NERC will also publish electricity supply and demand data associated with the long-term reliability assessment report.

2. **Summer Assessment Report** — The annual summer seasonal assessment report typically shall cover the four-month (June–September) summer period. It shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected summer peak demands. It shall also identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may include possible mitigation alternatives. The report will generally be published in mid-May for the upcoming summer period.

3. **Winter Assessment Report** — The annual winter seasonal assessment report shall cover the three-month (December–February) winter period. The report shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected winter peak demands. Similar to the summer assessment, the winter assessment shall identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may also include possible mitigation alternatives. The winter assessment report will generally be published in mid-November for the upcoming winter period.

4. **Special Reliability Assessment Reports** — In addition to the long-term and seasonal reliability assessment reports, NERC shall also conduct special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the Board or governmental authorities. The teams of reliability and technical experts also may initiate special assessments of key

reliability issues and their impacts on the reliability of a regions, subregions, or Interconnection (or a portion thereof). Such special reliability assessments may include, among other things, operational reliability assessments, evaluations of emergency response preparedness, adequacy of fuel supply, hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects or has the potential to affect the reliability of the interconnected Bulk Power Systems in North America.

804. Reliability Assessment Data and Information Requirements

To carry out the reviews and assessments of the overall reliability of the interconnected Bulk Power Systems, the Regional Entities and other entities shall provide sufficient data and other information requested by NERC in support of the annual long-term and seasonal assessments and any special reliability assessments.

Some of the data provided for these reviews and assessment may be considered confidential from a competitive marketing perspective, a Critical Energy Infrastructure Information perspective, or for other purposes. Such data shall be treated in accordance with the provisions of Section 1500 – Confidential Information.

While the major sources of data and information for this program are the Regional Entities, a team of reliability and technical experts is responsible for developing and formulating its own independent conclusions about the near-term and long-term reliability of the Bulk Power Systems.

In connection with the reliability assessment reports, requests shall be submitted to each of the Regional Entities for required reliability assessment data and other information, and for each Regional Entity's self-assessment report. The timing of the requests will be governed by the schedule for the preparation of the assessment reports.

The Regional Entity self-assessments are to be conducted in compliance with NERC Reliability Standards and the respective regional planning criteria. The team(s) of reliability and technical experts shall also conduct interviews with the Regional Entities as needed. The summary of the Regional Entity self-assessments that are to be included in the assessment reports shall follow the general outline identified in NERC's request. This outline may change from time to time as key reliability issues change.

In general, the Regional Entity reliability self-assessments shall address, among other areas, the following topics: demand and Net Energy for Load; assessment of projected resource adequacy; any transmission constraints that may impact bulk transmission adequacy and plans to alleviate those constraints; any unusual operating conditions that could impact reliability for the assessment period; fuel supply adequacy; the deliverability of generation (both internal and external) to Load; and any other reliability issues in the Region and their potential impacts on the reliability of the Bulk Power Systems.

805. Reliability Assessment Process

Based on their expertise, the review of the collected data, the review of the Regional Entity self-assessment reports, and interviews with the Regional Entities, as appropriate, the teams of reliability and technical experts shall perform an independent review and assessment of the generation and transmission adequacy of each Region's existing and planned Bulk Power System. The results of the review teams shall form the basis of NERC's long-term and seasonal reliability assessment reports. The review and assessment process is briefly summarized below.

1. **Resource Adequacy Assessment** — The teams shall evaluate the regional demand and resource capacity data for completeness in the context of the overall resource capacity needs of the Region. The team shall independently evaluate the ability of the Regional Entity members to serve their obligations given the demand growth projections, the amount of existing and planned capacity, including committed and uncommitted capacity, contracted capacity, or capacity outside of the Region. If the Region relies on capacity from outside of the Region to meet its resource objectives, the ability to deliver that capacity shall be factored into the assessment. The demand and resource capacity information shall be compared to the resource adequacy requirements of the Regional Entity for the year(s) or season(s) being assessed. The assessment shall determine if the resource information submitted represents a reasonable and attainable plan for the Regional Entity and its members. For cases of inadequate capacity or reserve margin, the Regional Entity will be requested to analyze and explain any resource capacity inadequacies and its plans to mitigate the reliability impact of the potential inadequacies. The analysis may be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable Regions. The results of these analyses shall be described in the assessment report.

2. **Transmission Adequacy and Operating Reliability Assessment** — The teams shall evaluate transmission system information that relates to the adequacy and operating reliability of the regional transmission system. That information shall include: regional planning study reports, interregional planning study reports, and/or regional operational study reports. If additional information is required, another data request shall be sent to the Regional Entity. The assessment shall provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the assessment period as required by NERC Reliability Standards. If sub-areas of the regional system are especially critical to the Reliable Operation of the regional bulk transmission system, these Facilities or sub-areas shall be reviewed and addressed in the assessment. Any areas of concern related to the adequacy or operating reliability of the system shall be identified and reported in the assessment.

3. **Seasonal Operating Reliability Assessment** — The team(s) shall evaluate the overall operating reliability of the regional bulk transmission systems. In areas with potential resource adequacy or system operating reliability problems,

operational readiness of the affected Regional Entities for the upcoming season shall be reviewed and analyzed. The assessment may consider unusual but possible operating scenarios and how the system is expected to perform. Operating reliability shall take into account a wide range of activities, all of which should reinforce the Regional Entity's ability to deal with the situations that might occur during the upcoming season. Typical activities in the assessment may include: facility modifications and additions, new or modified operating procedures, emergency procedures enhancement, and planning and operating studies. The teams shall report the overall seasonal operating reliability of the regional transmission systems in the annual summer and winter assessment reports.

4. **Reporting of Reliability Assessment Results** — The teams of reliability and technical experts shall provide an independent assessment of the reliability of the Regional Entities and the North American interconnected Bulk Power System for the period of the assessment. While the Regional Entities are relied upon to provide the information to perform such assessments, the review team is not required to accept the conclusions provided by the Regional Entities. Instead, the review team is expected, based on their expertise, to reach their own independent conclusions about the status of the adequacy of the generation and bulk power transmission systems of North America.

   The review team also shall strive to achieve consensus in their assessments. The assessments that are made are based on the best information available at the time. However, since judgment is applied to this information, legitimate differences of opinion can develop. Despite these differences, the review team shall work to achieve consensus on their findings.

   In addition to providing long-term and seasonal assessments in connection with the Reliability Assessment Program, the review team of experts shall also be responsible for recommending new and revised Reliability Standards related to the reliability assessments and the reliability of the Bulk Power Systems. These proposals for new or revised Reliability Standards shall be entered into NERC's Reliability Standards development process.

   Upon completion of the assessment, the team shall share the results with the Regional Entities. The Regional Entities shall be given the opportunity to review and comment on the conclusions in the assessment and to provide additional information as appropriate. The reliability assessments and their conclusions are the responsibility of NERC's technical review team and NERC.

   The preparation and approval of NERC's reliability assessment reports shall follow a prescribed schedule including review, comment, and possible approval by appropriate NERC committees. The long-term and seasonal (summer and winter) reliability assessment reports shall be further reviewed for approval by the Board for publication to the electric industry.

806. Scope of the Reliability Performance and Analysis Program

The components of the program will include analysis of large-scale outages, disturbances, and near misses to determine root causes and lessons learned; identification and continuous monitoring of performance indices to detect emerging trends and signs of a decline in reliability performance; and communications of performance results, trends, recommendations, and initiatives to those responsible to take actions; followed with confirmation of actions to correct any deficiencies identified. Within NERC, the reliability performance program will provide performance results to the Reliability Standards Development and Compliance Monitoring and Enforcement Programs to make the necessary adjustments to preserve reliability based on a risk-based approach.

807. Analysis of Major Events

Responding to major events affecting the Bulk Power System such as significant losses of Load or generation, significant Bulk Power System disturbances, or other emergencies on the Bulk Power System, can be divided into four phases: situational assessment and communications; situation tracking and communications; data collection, investigation, analysis, and reporting; and follow-up on recommendations.

1. NERC's role following a major event is to provide leadership, coordination, technical expertise, and assistance to the industry in responding to the major event. Working closely with the Regional Entities and Reliability Coordinators, and other appropriate Registered Entities, NERC will coordinate and facilitate efforts among industry participants, and with state, federal, and provincial governments in the United States and Canada to support the industry's response.

2. When responding to any major event where physical or cyber security is suspected as a cause or contributing factor to the major event, NERC will immediately notify appropriate government agencies and coordinate its activities with them.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator of the Bulk Power System shall also provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entity as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

4. During the conduct of NERC analyses, assistance may be needed from government agencies. This assistance could include: authority to require data reporting from affected or involved parties; communications with other agencies of government; investigations related to possible criminal or terrorist involvement in the major event; resources for initial data gathering immediately after the major

event; authority to call meetings of affected or involved parties; and technical and analytical resources for studies.

5. NERC shall work with all other participants to establish a clear delineation of roles, responsibilities, and coordination requirements among industry and government for the investigation and reporting of findings, conclusions, and recommendations related to major events with the objective of avoiding, to the extent possible, multiple investigations of the same major event. If the major event is confined to a single Regional Entity, NERC representatives will participate as members of the Regional Entity analysis team. NERC will establish, maintain, and revise from time to time as appropriate based on experience, a manual setting forth procedures and protocols for communications and sharing and exchange of information between and among NERC, the affected Regional Entity or Entities, and relevant governmental authorities, industry organizations and Bulk Power System user, owners, and operators concerning the investigation and analysis of major events.

6. NERC and applicable entity(s) will apply, as appropriate to the circumstances of the major event, the NERC *Blackout and Disturbance Response Procedures*, which are incorporated into these Rules of Procedure as **Appendix 8**. These procedures provide a framework to guide NERC's response to major events that may have multiregional, national, or international implications. Experienced industry leadership shall be applied to tailor the response to the specific circumstances of the major event. In accordance with those procedures, the NERC president will determine whether the major event warrants analysis at the NERC level. A Regional Entity may request that NERC elevate any analysis of a major event to the NERC level.

7. NERC will screen and analyze the findings and recommendations from the analysis, and those with generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities

1. NERC and Regional Entities will analyze Bulk Power System and equipment performance occurrences that do not rise to the level of a major event, as described in Section 807. NERC and Regional Entities will also analyze potential vulnerabilities in the Bulk Power System that they discover or that are brought to their attention by other sources including government agencies. The purpose of these analyses is to identify the root causes of occurrences or conditions that may be precursors of major events or other potentially more serious occurrences, or that have the potential to cause major events or other more serious occurrences, to assess past reliability performance for lessons learned, and to develop reliability performance benchmarks and trends.

2. NERC and Regional Entities will screen and analyze off-normal occurrences, Bulk Power System performance, and potential Bulk Power System vulnerabilities for significance, and information from those indicated as having generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator, of the Bulk Power System shall provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entities as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

809. Reliability Benchmarking

NERC shall identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include assessing available metrics, developing guidelines for acceptable metrics, maintaining a performance metrics "dashboard" on the NERC website, and developing appropriate reliability performance benchmarks.

810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions

1. Members of NERC and Bulk Power System owners, operators, and users shall provide NERC with detailed and timely operating experience information and data.

2. In the normal course of operations, NERC disseminates the results of its events analysis findings, lessons learned and other analysis and information gathering to the industry. These findings, lessons learned and other information will be used to guide the Reliability Assessment Program.

3. When NERC determines it is necessary to place the industry or segments of the industry on formal notice of its findings, analyses, and recommendations, NERC will provide such notification in the form of specific operations or equipment Advisories, Recommendations or Essential Actions:

   3.1 Level 1 (Advisories) – purely informational, intended to advise certain segments of the owners, operators and users of the Bulk Power System of findings and lessons learned;

   3.2 Level 2 (Recommendations) – specific actions that NERC is recommending be considered on a particular topic by certain segments of

owners, operators, and users of the Bulk Power System according to each entity's facts and circumstances;

3.3 Level 3 (Essential Actions) – specific actions that NERC has determined are essential for certain segments of owners, operators, or users of the Bulk Power System to take to ensure the reliability of the Bulk Power System. Such Essential Actions require NERC Board approval before issuance.

4. The Bulk Power System owners, operators, and users to which Level 2 (Recommendations) and Level 3 (Essential Actions) notifications apply are to evaluate and take appropriate action on such issuances by NERC. Such Bulk Power System owners, operators, and users shall also provide reports of actions taken and timely updates on progress towards resolving the issues raised in the Recommendations and Essential Actions in accordance with the reporting date(s) specified by NERC.

5. NERC will advise the Commission and other Applicable Governmental Authorities of its intent to issue all Level 1 (Advisories), Level 2 (Recommendations), and Level 3 (Essential Actions) at least five (5) business days prior to issuance, unless extraordinary circumstances exist that warrant issuance less than five (5) business days after such advice. NERC will file a report with the Commission and other Applicable Governmental Authorities no later than thirty (30) days following the date by which NERC has requested the Bulk Power System owners, operators, and users to which a Level 2 (Recommendation) or Level 3 (Essential Action) issuance applies to provide reports of actions taken in response to the notification. NERC's report to the Commission and other Applicable Governmental Authorities will describe the actions taken by the relevant owners, operators, and users of the Bulk Power System and the success of such actions taken in correcting any vulnerability or deficiency that was the subject of the notification, with appropriate protection for Confidential Information or Critical Energy Infrastructure Information.

811. Equipment Performance Data

Through its Generating Availability Data System (GADS), NERC shall collect operating information about the performance of electric generating equipment; provide assistance to those researching information on power plant outages stored in its database; and support equipment reliability as well as availability analyses and other decision-making processes developed by GADS subscribers. GADS data is also used in conducting assessments of generation resource adequacy.

SECTION 900 — TRAINING AND EDUCATION

901. Scope of the Training and Education Program

~~Maintaining~~ Assuring the ~~reliability~~ Reliable Operation of the North American Bulk ~~Electric~~ Power System requires informed knowledgeable and skilled personnel. NERC shall develop a program to oversee the coordination and delivery of learning materials, resources, and activities to allow for training and education of:

1. ERO Enterprise staff supporting statutory and delegation-related activities; and

2. Bulk Power System industry participants consistent with ERO functional program requirements.~~through implementation of the Reliability Standards requires informed and trained personnel. The training and education program will provide the education and training necessary for Bulk Power System personnel and regulators to obtain the essential knowledge necessary to understand and operate the Bulk Electric System.~~

~~NERC shall develop and maintain training and education programs for the purpose of establishing training requirements, developing materials, and developing training activities. The target audience of the training and education programs shall be Bulk Power System operating personnel including system operations personnel, operations support personnel (engineering and information technology), supervisors and managers, training personnel, and other personnel directly responsible for complying with NERC Reliability Standards who, through their actions or inactions, may impact the real-time, or day-ahead reliability of the Bulk Power System.~~

~~2. NERC shall also develop and provide appropriate training and education for industry participants and regulators affected by new or changed Reliability Standards or compliance Requirements.~~

~~To accomplish those objectives:~~

~~1. NERC shall periodically conduct job task analyses for targeted Bulk Power System personnel to ensure that the training program content is properly aligned to the job tasks performed by those personnel.~~

~~2. NERC shall develop and maintain personnel training program curriculum requirements based on valid job-task analysis.~~

~~3. NERC shall periodically conduct performance surveys to determine the effectiveness of the training program and identify areas for further training development and improvement.~~

~~4. NERC shall develop training and education materials and activities to assist Bulk Power System entities implementing new or revised Reliability Standard Requirements or other NERC-related changes.~~

~~5. NERC shall develop and provide training to people who participate in NERC and Regional Entity evaluations, audits, and investigations for the Compliance Monitoring and Enforcement Program, Organization Certification Program, and the continuing education program.~~

902. Continuing Education Program

1. NERC shall develop and maintain a continuing education program to ~~foster the improvement of training and to promote quality in the training programs used by and implemented by Bulk Power System entities. The program shall~~ approve ~~or accredit~~ those activities and entities meeting NERC continuing education requirements.

~~1. NERC shall develop and implement continuing education program requirements that promote excellence in training programs and advance improved performance for Bulk Power System personnel identified in Section 901.~~

2. The Personnel Subcommittee (PS), which reports to the NERC Operating Committee, is the governing body of the NERC Continuing Education Program that oversees development and implementation of the Continuing Education Program requirements.~~NERC shall develop and maintain a process to approve or accredit continuing education Providers and activities seeking approval or accreditation and meeting NERC-approved continuing education requirements.~~

3. ~~NERC shall perform periodic audits on continuing education Providers and training activities to ensure that the approved or accredited Providers and training activities satisfy NERC continuing education requirements~~The PS shall develop and update, as necessary, ~~annually review and publish a Continuing Education Administrative~~ m~~M~~anual, approved by the Operating Committee, which describes the following:~~.~~

   3.1 Requirements for approving contining education Providers and activities;

   3.2 Requirements for auditing continuing education Providers and activities;

   3.3 Multi-layer review process for disputed application reviews, interpretations of guideline and standards, probation or suspension of NERC-approved Provider status, and Continuing Education Hour disputes; and

   3.4 Requirements on fees for continuing education Providers and activities.

~~4. NERC shall develop and maintain an appeals process for disputed application reviews, interpretations of guidelines and standards, probation or suspension of NERC-approved Provider status, or Continuing Education Hour disputes.~~

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY

1001. Situation Awareness

NERC shall through the use of Reliability Coordinators and available tools, monitor present conditions on the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary. To accomplish these goals, NERC will:

1. Maintain real-time situation awareness of conditions on the Bulk Power System;

2. Notify the industry of significant Bulk Power System events that have occurred in one area, and which have the potential to impact reliability in other areas;

3. Maintain and strengthen high-level communication, coordination, and cooperation with governments and government agencies regarding real-time conditions; and

4. Enable the Reliable Operation of interconnected Bulk Power Systems by facilitating information exchange and coordination among reliability service organizations.

1002. Reliability Support Services

NERC may assist in the development of tools and other support services for the benefit of Reliability Coordinators and other system operators to enhance reliability, operations and planning. NERC will work with the industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period, transition the tool or service to another group or owner for long term operation of the tool or provision of the service. To accomplish this goal, NERC will:

1. Collaborate with industry to determine the necessity of new tools or services to enhance reliability;

2. For those tools that the collaborative process determines should proceed to a development phase, provide a start-up mechanism and development system;

3. Implement the tool either on its own or through an appropriate group or organization; and

4. Where NERC conducts the implementation phase of a new tool or service, develop a transition plan to turn maintenance and provision of the tool or service over to an organization identified in the development stage.

In addition to tools developed as a result of a collaborative process with industry, NERC may develop reliability tools on its own, but will consult with industry concerning the need for the tool prior to proceeding to development.

Tools and services being maintained by NERC as of January 1, 2012, will be reviewed and, as warranted, transitioned to an appropriate industry group or organization. NERC will develop and maintain a strategic reliability tools plan that will list the tools and services being maintained by NERC, and, where applicable, the plans for transition to an appropriate industry group or organization.

1003. Infrastructure Security Program

NERC shall coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America by taking a leadership role in Critical Infrastructure protection of the electricity sector so as to reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure. To accomplish these goals, NERC shall perform the following functions.

1. Electric Sector Information Sharing and Analysis Center (ESISAC)

    1.1 NERC shall serve as the electricity sector's sector coordinator and operate its Information Sharing and Analysis Center to gather information and communicate security-related threats and incidents within the sector, with United States and Canadian government agencies, and with other Critical Infrastructure sectors.

    1.2 NERC shall improve the capability of the ESISAC to analyze security threats and incident information and provide situational assessments for the electricity sector and governments.

    1.3 NERC shall work closely with the United States Department of Homeland Security, Department of Energy, Natural Resources Canada, and Public Safety and Emergency Preparedness Canada.

    1.4 NERC shall strengthen and expand these functions and working relationships with the electricity sector, other Critical Infrastructure industries, governments, and government agencies throughout North America to ensure the protection of the infrastructure of the Bulk Power System.

    1.5 NERC shall fill the role of the Electricity Sector Coordinating Council and coordinate with the Government Coordinating Council.

    1.6 NERC shall coordinate with other Critical Infrastructure sectors through active participation with the other Sector Coordinating Councils, the other ISACs, and the National Infrastructure Advisory Committee.

    1.7 NERC shall encourage and participate in coordinated Critical Infrastructure protection exercises, including interdependencies with other Critical Infrastructure sectors.

2. Security Planning

2.1 NERC shall take a risk management approach to Critical Infrastructure protection, considering probability and severity, and recognizing that mitigation and recovery can be practical alternatives to prevention.

2.2 NERC shall keep abreast of the changing threat environment through collaboration with government agencies.

2.3 NERC shall develop criteria to identify critical physical and cyber assets, assess security threats, identify risk assessment methodologies, and assess effectiveness of physical and cyber protection measures.

2.4 NERC shall enhance and maintain the Bulk Power System critical spare transformer program, encourage increased participation by asset owners, and continue to assess the need to expand this program to include other critical Bulk Power System equipment.

2.5 NERC shall support implementation of the Critical Infrastructure Protection Standards through education and outreach.

2.6 NERC shall review and improve existing security guidelines, develop new security guidelines to meet the needs of the electricity sector, and consider whether any guidelines should be developed into Reliability Standards.

2.7 NERC shall conduct education and outreach initiatives to increase awareness and respond to the needs of the electricity sector.

2.8 NERC shall strengthen relationships with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.9 NERC shall maintain and improve mechanisms for the sharing of sensitive or classified information with federal, state, and provincial government agencies on Critical Infrastructure protection matters; work with DOE and DHS to implement the National Infrastructure Protection Plan, as applicable to the electricity sector; and coordinate this work with PSEPC.

2.10 NERC shall improve methods to better assess the impact of a possible physical attack on the Bulk Power System and means to deter, mitigate, and respond following an attack.

2.11 NERC shall assess the results of vulnerability assessments and enhance the security of system control and data acquisition (SCADA) and process control systems by developing methods to detect an emerging cyber attack and the means to mitigate impacts on the Bulk Power Systems.

2.12 NERC shall work with the National SCADA Test Bed and the Process Control Systems Forum to accelerate the development of technology that will enhance the security, safety, and reliability of process control and SCADA systems.

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS

1101. Scope of Business Plans and Budgets

The Board shall determine the content of the budgets to be submitted to the Applicable Governmental Authorities with consultation from the members of the Member Representatives Committee, Regional Entities, and others in accordance with the Bylaws. The Board shall identify any activities outside the scope of NERC's statutory reliability functions, if any, and the appropriate funding mechanisms for those activities.

1102. NERC Funding and Cost Allocation

1. In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on Net Energy for Load (NEL).

2. NERC's costs shall be allocated so that all Load (or, in the case of costs for an Interconnection or Regional Entity, all Load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.

3. Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.

4. Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on Net Energy for Load.

1103. NERC Budget Development

~~1.~~3. The NERC annual budget process shall be scheduled and conducted for each calendar year so as to allow a sufficient amount of time for NERC to receive Member inputs, develop the budget, and receive Board and, where authorized by applicable legislation or agreement, Applicable Governmental Authority approval of the NERC budget for the following fiscal year, including timely submission of the proposed budget to FERC for approval in accordance with FERC regulations.

~~2.~~4. The NERC budget submittal to Applicable Governmental Authorities shall include provisions for all ERO functions, all Regional Entity delegated functions as specified in delegation agreements and reasonable reserves and contingencies.

~~3.~~5. The NERC annual budget submittal to Applicable Governmental Authorities shall include description and explanation of NERC's proposed ERO program activities for the year; budget component justification based on statutory or other authorities; explanation of how each budgeted activity lends itself to the accomplishment of the statutory or other authorities; sufficiency of resources provided for in the budget to carry out the ERO program responsibilities;

explanation of the calculations and budget estimates; identification and explanation of changes in budget components from the previous year's budget; information on staffing and organization charts; and such other information as is required by FERC and other Applicable Governmental Authorities having authority to approve the proposed budget.

~~4.~~6. NERC shall develop, in consultation with the Regional Entities, a reasonable and consistent system of accounts, to allow a meaningful comparison of actual results at the NERC and Regional Entity level by the Applicable Governmental Authorities.

1104. Submittal of Regional Entity Budgets to NERC

1. Each Regional Entity shall submit its proposed annual budget for carrying out its delegated authority functions as well as all other activities and funding to NERC in accordance with a schedule developed by NERC and the Regional Entities, which shall provide for the Regional Entity to submit its final budget that has been approved by its board of directors or other governing body no later than July 1 of the prior year, in order to provide sufficient time for NERC's review and comment on the proposed budget and approval of the Regional Entity budget by the NERC Board of Trustees in time for the NERC and Regional Entity budgets to be submitted to FERC and other Applicable Governmental Authorities for approval in accordance with their regulations. The Regional Entity's budget shall include supporting materials in accordance with the budget and reporting format developed by NERC and the Regional Entities, including the Regional Entity's complete business plan and organization chart, explaining the proposed collection of all dues, fees, and charges and the proposed expenditure of funds collected in sufficient detail to justify the requested funding collection and budget expenditures.

2. NERC shall review and approve each Regional Entity's budget for meeting the requirements of its delegated authority. Concurrent with approving the NERC budget, NERC shall review and approve, or reject, each Regional Entity budget for filing.

3. NERC shall also have the right to review from time to time, in reasonable intervals but no less frequently than every three years, the financial books and records of each Regional Entity having delegated authority in order to ensure that the documentation fairly represents in all material aspects appropriate funding of delegated functions.

1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval

1. NERC shall file for approval by the Applicable Governmental Authorities at least 130 days in advance of the start of each fiscal year. The filing shall include: (1) the complete NERC and Regional Entity budgets including the business plans and organizational charts approved by the Board, (2) NERC's annual funding

requirement (including Regional Entity costs for delegated functions), and (3) the mechanism for assessing charges to recover that annual funding requirement, together with supporting materials in sufficient detail to support the requested funding requirement.

2. NERC shall seek approval from each Applicable Governmental Authority requiring such approval for the funding requirements necessary to perform ERO activities within their jurisdictions.

1106. NERC and Regional Entity Billing and Collections

1. NERC shall request the Regional Entities to identify all Load-Serving Entities[3] within each Regional Entity and the NEL assigned to each Load-Serving Entity, and the Regional Entities shall supply the requested information. The assignment of a funding requirement to an entity shall not be the basis for determining that the entity must be registered in the Compliance Registry.

2. NERC shall accumulate the NEL by Load-Serving Entities for each Applicable Governmental Authority and submit the proportional share of NERC funding requirements to each Applicable Governmental Authority for approval together with supporting materials in sufficient detail to support the requested funding requirement.

3. NEL reported by Balancing Authorities within a Region shall be used to rationalize and validate amounts allocated for collection through Regional Entity processes.

4. The billing and collection processes shall provide:

   4.1 A clear validation of billing and application of payments.

   4.2 A minimum of data requests to those being billed.

   4.3 Adequate controls to ensure integrity in the billing determinants including identification of entities responsible for funding NERC's activities.

   4.4 Consistent billing and collection terms.

5. NERC will bill and collect all budget requirements approved by Applicable Governmental Authorities (including the funds required to support those functions assigned to the Regional Entities through the delegation agreements) directly from the Load-Serving Entities or their designees or as directed by particular Applicable Governmental Authorities, except where the Regional Entity is required to collect the budget requirements for NERC, in which case the Regional

[3] A Regional Entity may allocate funding obligations using an alternative method approved by NERC and by FERC and other Applicable Governmental Authorities, as provided for in the regional delegation agreement.

Entity will collect directly from the Load-Serving Entities or as otherwise provided by agreement and submit funds to NERC. Alternatively, a load-serving entity may pay its allocated ERO costs through a Regional Entity managed collection mechanism.

6. NERC shall set a minimum threshold limit on the billing of small LSEs to minimize the administrative burden of collection.

7. NERC shall pursue any non-payments and shall request assistance from Applicable Governmental Authorities as necessary to secure collection.

8. In the case where a Regional Entity performs the collection for ERO, the Regional Entity will not be responsible for non-payment in the event that a user, owner or operator of the Bulk Power System does not pay its share of dues, fees and charges in a timely manner, provided that such a Regional Entity shall use reasonably diligent efforts to collect dues, fees, and other charges from all entities obligated to pay them. However, any revenues not paid shall be recovered from others within the same Region to avoid cross-subsidization between Regions.

9. Both NERC and the Regional Entities also may bill members or others for functions and services not within statutory requirements or otherwise authorized by the Applicable Governmental Authorities. Costs and revenues associated with these functions and services shall be separately identified and not commingled with billings associated with the funding of NERC or of the Regional Entities for delegated activities.

1107. Penalty Applications

1. Where NERC or a Regional Entity initiates a compliance monitoring and enforcement process that leads to imposition of a Penalty, the entity that initiated the process shall receive any Penalty monies imposed and collected as a result of that process, unless a different disposition of the Penalty monies is provided for in the delegation agreement, or in a contract or a disposition of the violation that is approved by NERC and FERC.

2. 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 requirements 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. Funds from financial Penalties assessed against a Canadian entity shall be applied as specified by legislation or agreement.

3. In the event that a compliance monitoring and enforcement process is conducted jointly by NERC and a Regional Entity, the Regional Entity shall receive the Penalty monies and offset the Regional Entity's budget requirements for the subsequent fiscal year.

4. Exceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by FERC or any other Applicable Governmental Authority.

1108. Special Assessments

On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next funding cycle, NERC shall file with the Applicable Governmental Authorities, where authorized by applicable legislation or agreement, for authorization for an amended or supplemental budget for NERC or a Regional Entity and, if necessary under the amended or supplemental budget, to collect a special or additional assessment for statutory functions of NERC or the Regional Entity. Such filing shall include supporting materials to justify the requested funding, including any departure from the approved funding formula or method.

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS

1201. Pro Forma Regional Delegation Agreement

NERC shall develop and maintain a pro forma Regional Entity delegation agreement, which shall serve as the basis for negotiation of consistent agreements for the delegation of ERO functions to Regional Entities.

1202. Regional Entity Essential Requirements

NERC shall establish the essential requirements for an entity to become qualified and maintain good standing as a Regional Entity.

1203. Negotiation of Regional Delegation Agreements

NERC shall, for all areas of North America that have provided NERC with the appropriate authority, negotiate regional delegation agreements for the purpose of ensuring all areas of the North American Bulk Power Systems are within a Regional Entity Region. In the event NERC is unable to reach agreement with Regional Entities for all areas, NERC shall provide alternative means and resources for implementing NERC functions within those areas. No delegation agreement shall take effect until it has been approved by the Applicable Governmental Authority.

1204. Conformance to Rules and Terms of Regional Delegation Agreements

NERC and each Regional Entity shall comply with all applicable ERO Rules of Procedure and the obligations stated in the regional delegation agreement.

1205. Sub-delegation

The Regional Entity shall not sub-delegate any responsibilities and authorities delegated to it by its regional delegation agreement with NERC except with the approval of NERC and FERC and other Applicable Governmental Authorities. Responsibilities and authorities may only be sub-delegated to another Regional Entity. Regional Entities may share resources with one another so long as such arrangements do not result in cross-subsidization or in any sub-delegation of authorities.

1206. Nonconformance to Rules or Terms of Regional Delegation Agreement

If a Regional Entity is unable to comply or is not in compliance with an ERO Rule of Procedure or the terms of the regional delegation agreement, the Regional Entity shall immediately notify NERC in writing, describing the area of nonconformance and the reason for not being able to conform to the Rule of Procedure. NERC shall evaluate each case and inform the affected Regional Entity of the results of the evaluation. If NERC determines that a Rule of Procedure or term of the regional delegation agreement has been violated by a Regional Entity or cannot practically be implemented by a Regional Entity, NERC shall notify the Applicable Governmental Authorities and take any actions necessary to address the situation.

1207. Regional Entity Audits

Approximately every five years and more frequently if necessary for cause, NERC shall audit each Regional Entity to verify that the Regional Entity continues to comply with NERC Rules of Procedure and the obligations of NERC delegation agreement. Audits of Regional Entities shall be conducted, to the extent practical, based on professional auditing standards recognized in the U.S., including Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors, and if applicable to the coverage of the audit, may be based on Canadian or other international standards. The audits required by this Section 1207 shall not duplicate the audits of Regional Entity Compliance Monitoring and Enforcement Programs provided for in **Appendix 4A**, Audit of Regional Compliance Programs, to these Rules of Procedure.

1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity

1. A Registered Entity that is registered in the Region of one Regional Entity and believes its registration should be transferred to a different Regional Entity may submit a written request to both Regional Entities requesting that they process the proposed transfer in accordance with this section. The Registered Entity's written request shall set forth the reasons the Registered Entity believes justify the proposed transfer and shall describe any impacts of the proposed transfer on other Bulk Power System owners, operators, and users.

2. After receiving the Registered Entity's written request, the two Regional Entities shall consult with each other as to whether they agree or disagree that the requested transfer is appropriate. The Regional Entities may also consult with affected Reliability Coordinators, Balancing Authorities and Transmission Operators as appropriate. Each Regional Entity shall post the request on its website for public comment period of 21 days. In evaluating the proposed transfer, the Regional Entities shall consider the location of the Registered Entity's Bulk Power System facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators; and users, the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load-Serving Entities of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity would be transitioned from the current Regional Entity to the transferee Regional Entity; along with any other reasons for the proposed transfer stated by the Registered Entity and any other reasons either Regional Entity considers relevant. The Regional Entities may request that the Registered Entity provide additional data and information concerning the proposed transfer for the Regional Entities' use in their evaluation. The Registered Entity's current Regional Entity shall notify the Registered Entity

in writing as to whether (i) the two Regional Entities agree that the requested transfer is appropriate, (ii) the two Regional Entities agree that the requested transfer is not appropriate and should not be processed further, or (iii) the two Regional Entities disagree as to whether the proposed transfer is appropriate.

3. If the two Regional Entities agree that the requested transfer is appropriate, they shall submit a joint written request to NERC requesting that the proposed transfer be approved and that the delegation agreement between NERC and each of the Regional Entities be amended accordingly. The Regional Entities' joint written submission to NERC shall describe the reasons for the proposed transfer; the location of the Registered Entity's Bulk Power System Facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators, and users; the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity will be transitioned from the current Regional Entity to the transferee Regional Entity. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

4. If the two Regional Entities do not agree with each other that the proposed transfer is appropriate, the Regional Entity supporting the proposed transfer shall, if requested by the Registered Entity, submit a written request to NERC to approve the transfer and the related delegation agreement amendments. The Regional Entity's written request shall include the information specified in Section 1208.3. The Regional Entity that does not believe the proposed transfer is appropriate will be allowed to submit a written statement to NERC explaining why the Regional Entity believes the transfer is not appropriate and should not be approved. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

5. Prior to action by the NERC Board of Trustees on a proposed transfer of registration under Section 1208.3 or 1208.4, NERC shall post information concerning the proposed transfer, including the submissions from the Regional Entities, on its website for at least twenty-one (21) days for the purpose of receiving public comment.

6. If the NERC Board of Trustees disapproves a proposed transfer presented to it pursuant to either Section 1208.3 or 1208.4, the Regional Entity or Regional Entities that believe the transfer is appropriate may, if requested to do so by the Registered Entity, file a petition with FERC pursuant to 18 C.F.R. section 39.8(f) and (g) requesting that FERC order amendments to the delegation agreements of the two Regional Entities to effectuate the proposed transfer.

7. No transfer of a Registered Entity from one Regional Entity to another Regional Entity shall be effective (i) unless approved by FERC, and (ii) any earlier than the first day of January of the second calendar year following approval by FERC, unless an earlier effective date is agreed to by both Regional Entities and NERC and approved by FERC.

SECTION 1300 — COMMITTEES

1301. Establishing Standing Committees

The Board may from time to time create standing committees. In doing so, the Board shall approve the charter of each committee and assign specific authority to each committee necessary to conduct business within that charter. Each standing committee shall work within its Board-approved charter and shall be accountable to the Board for performance of its Board-assigned responsibilities. A NERC standing committee may not delegate its assigned work to a member forum, but, in its deliberations, may request the opinions of and consider the recommendations of a member forum.

1302. Committee Membership

Each committee shall have a defined membership composition that is explained in its charter. Committee membership may be unique to each committee, and can provide for balanced decision-making by providing for representatives from each Sector or, where Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area, by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in a particular subject area. Committee membership shall also provide the opportunity for an equitable number of members from the United States and Canada, based approximately on proportionate Net Energy for Load. All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter. With regard to committees and subgroups pertaining to development of, interpretation of, or compliance with Reliability Standards, NERC shall provide a reasonable opportunity for membership from Sectors desiring to participate. Committees and subgroups organized on other than a Sector basis shall be reported to the NERC Board and the Member Representatives Committee, along with the reasons for constituting the committee or subgroup in the manner chosen. In such cases and subject to reasonable restrictions necessary to accomplish the mission of such committee or subgroup, NERC shall provide a reasonable opportunity for additional participation, as members or official observers, for Sectors not represented on the committee or subgroup.

1303. Procedures for Appointing Committee Members

Committee members shall be nominated and selected in a manner that is open, inclusive, and fair. Unless otherwise stated in these Rules of Procedure or approved by the Board, all committee member appointments shall be approved by the board, and committee officers shall be appointed by the Chairman of the Board.

1304. Procedures for Conduct of Committee Business

1. Notice to the public of the dates, places, and times of meetings of all committees, and all nonconfidential material provided to committee members, shall be posted on NERC's website at approximately the same time that notice is given to

committee members. Meetings of all standing 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 enforcement matters, litigation, or commercially sensitive or Critical Energy Infrastructure Information of any entity.

2. NERC shall maintain a set of procedures, approved by the Board, to guide the conduct of business by standing committees.

1305. Committee Subgroups

Standing committees may appoint subgroups using the same principles as in Section 1302.

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE

1401. Proposals for Amendment or Repeal of Rules of Procedure

In accordance with the Bylaws of NERC, requests to amend or repeal the Rules of Procedure may be submitted by (1) any fifty Members of NERC, which number shall include Members from at least three membership Sectors, (2) the Member Representatives Committee, (3) a committee of NERC to whose function and purpose the Rule of Procedure pertains, or (4) an officer of NERC.

1402. Approval of Amendment or Repeal of Rules of Procedure

Amendment to or repeal of Rules of Procedure shall be approved by the Board after public notice and opportunity for comment in accordance with the Bylaws of NERC. In approving changes to the Rules of Procedure, the Board shall consider the inputs of the Member Representatives Committee, other ERO committees affected by the particular changes to the Rules of Procedure, and other stakeholders as appropriate. After Board approval, the amendment or repeal shall be submitted to the Applicable Governmental Authorities for approval, where authorized by legislation or agreement. No amendment to or repeal of the Rules of Procedure shall be effective until it has been approved by the Applicable Governmental Authorities.

SECTION 1500 — CONFIDENTIAL INFORMATION

1501. Definitions

1. **Confidential Information** means (i) Confidential Business and Market Information; (ii) Critical Energy Infrastructure Information; (iii) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (iv) work papers, including any records produced for or created in the course of an evaluation or audit; (v) investigative files, including any records produced for or created in the course of an investigation; or (vi) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition.

2. **Confidential Business and Market Information** means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

3. **Critical Energy Infrastructure Information** means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.

4. **Critical Infrastructure** means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

5. **Cyber Security Incident Information** means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

1502. Protection of Confidential Information

1. **Identification of Confidential Information** — An owner, operator, or user of the Bulk Power System and any other party (the "Submitting Entity") shall mark as confidential any information that it submits to NERC or a Regional Entity (the "Receiving Entity") that it reasonably believes contains Confidential Information as defined by these Rules of Procedure, indicating the category or categories defined in Section 1501 in which the information falls. If the information is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the Submitting Entity shall so indicate and provide supporting references and details.

2. **Confidentiality** — Except as provided herein, a Receiving Entity shall keep in confidence and not copy, disclose, or distribute any Confidential Information or

any part thereof without the permission of the Submitting Entity, except as otherwise legally required.

3. **Information no longer Confidential –** If a Submitting Entity concludes that information for which it had sought confidential treatment no longer qualifies for that treatment, the Submitting Entity shall promptly so notify NERC or the relevant Regional Entity.

1503. Requests for Information

1. **Limitation** — A Receiving Entity shall make information available only to one with a demonstrated need for access to the information from the Receiving Entity.

2. **Form of Request** — A person with such a need may request access to information by using the following procedure:

   2.1 The request must be in writing and clearly marked "Request for Information."

   2.2 The request must identify the individual or entity that will use the information, explain the requester's need for access to the information, explain how the requester will use the information in furtherance of that need, and state whether the information is publicly available or available from another source or through another means. If the requester seeks access to information that is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the requester shall describe how it qualifies to receive such information.

   2.3 The request must stipulate that, if the requester does not seek public disclosure, the requester will maintain as confidential any information received for which a Submitting Party has made a claim of confidentiality in accordance with NERC's rules. As a condition to gaining access to such information, a requester shall execute a non-disclosure agreement in a form approved by NERC's Board of Trustees.

3. **Notice and Opportunity for Comment** — Prior to any decision to disclose information marked as confidential, the Receiving Entity shall provide written notice to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed. Failure to provide such comments or otherwise respond is not deemed waiver of the claim of confidentiality.

4. **Determination by ERO or Regional Entity** — Based on the information provided by the requester under Rule 1503.2, any comments provided by the Submitting Entity, and any other relevant available information, the chief

executive officer or his or her designee of the Receiving Entity shall determine whether to disclose such information.

5. **Appeal** — A person whose request for information is denied in whole or part may appeal that determination to the President of NERC (or the President's designee) within 30 days of the determination. Appeals filed pursuant to this Section must be in writing, addressed to the President of NERC (or the President's designee), and clearly marked "Appeal of Information Request Denial."

   NERC will provide written notice of such appeal to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed; provided that any such comments must be received within 30 days of the notice and any failure to provide such comments or otherwise respond is not deemed a waiver of the claim of confidentiality.

   The President of NERC (or the President's designee) will make a determination with respect to any appeal within 30 days. In unusual circumstances, this time limit may be extended by the President of NERC (or the President's designee), who will send written notice to the requester setting forth the reasons for the extension and the date on which a determination on the appeal is expected.

6. **Disclosure of Information** — In the event the Receiving Entity, after following the procedures herein, determines to disclose information designated as Confidential Information, it shall provide the Submitting Entity no fewer than 21 days' written notice prior to releasing the Confidential Information in order to enable such Submitting Entity to (a) seek an appropriate protective order or other remedy, (b) consult with the Receiving Entity with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. Should a Receiving Entity be required to disclose Confidential Information, or should the Submitting Entity waive objection to disclosure, the Receiving Entity shall furnish only that portion of the Confidential Information which the Receiving Entity's counsel advises is legally required.

7. **Posting of Determinations on Requests for Disclosure of Confidential Information** — Upon making its determination on a request for disclosure of Confidential Information, NERC or the Regional Entity, as applicable, shall (i) notify the requester that the request for disclosure is granted or denied, (ii) publicly post any determination to deny the request to disclose Confidential Information, including in such posting an explanation of the reasons for the denial (but without in such explanation disclosing the Confidential Information), and (iii) publicly post any determination that information claimed by the Submitting Entity to be Confidential Information is not Confidential Information (but without in such posting disclosing any information that has been determined to be Confidential Information).

1504. Employees, Contractors and Agents

A Receiving Entity shall ensure that its officers, trustees, directors, employees, subcontractors and subcontractors' employees, and agents to whom Confidential Information is exposed are under obligations of confidentiality that are at least as restrictive as those contained herein.

1505. Provision of Information to FERC and Other Governmental Authorities

1. **Request** — A request from FERC for reliability information with respect to owners, operators, and users of the Bulk Power System within the United States is authorized by Section 215 of the Federal Power Act. Other Applicable Governmental Authorities may have similar authorizing legislation that grants a right of access to such information. Unless otherwise directed by FERC or its staff or the other Applicable Governmental Authority requesting the information, upon receiving such a request, a Receiving Entity shall provide contemporaneous notice to the applicable Submitting Entity. In its response to such a request, a Receiving Entity shall preserve any mark of confidentiality and shall notify FERC or other Applicable Governmental Authorities that the Submitting Entity has marked the information as confidential.

2. **Continued Confidentiality** — Each Receiving Entity shall continue to treat as confidential all Confidential Information that it has submitted to NERC or to FERC or another Applicable Governmental Authority, until such time as FERC or the other Applicable Governmental Authority authorizes disclosure of such information.

1506. Permitted Disclosures

1. **Confirmed Violations** — Nothing in this Section 1500 shall prohibit the disclosure of a violation at the point when the matter is filed with an Applicable Governmental Authority as a Notice of Penalty, the "violator" admits to the violation, or the alleged violator and NERC or the Regional Entity reach a settlement regarding the violation.

2. **Compliance Information** — NERC and the Regional Entities are authorized to exchange Confidential Information related to evaluations, Compliance Audits, and Compliance Investigations in furtherance of the Compliance Monitoring and Enforcement Program, on condition they continue to maintain the confidentiality of such information.

1507. Remedies for Improper Disclosure

Any person engaged in NERC or Regional Entity activity under Section 215 of the Federal Power Act or the equivalent laws of other Applicable Governmental Authorities who improperly discloses information determined to be confidential may lose access to Confidential Information on a temporary or permanent basis and may be subject to adverse personnel action, including suspension or termination. Nothing in Section 1500

precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION

1601. Scope of a NERC or Regional Entity Request for Data or Information

Within the United States, NERC and Regional Entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d). In other jurisdictions NERC and Regional Entities may request comparable data or information, using such authority as may exist pursuant to these Rules of Procedure and as may be granted by Applicable Governmental Authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information; the Requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.

1602. Procedure for Authorizing a NERC Request for Data or Information

1. NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified in Section 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with Section 1602.2 or issuing the request or modification to Reporting Entities following approval by the Board of Trustees.

2. NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.

    2.1. A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information ("Reporting Entities"); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., "Confidential Information," "Critical Energy Infrastructure Information," "aggregating"

or "identity masking"); and (vi) an estimate of the relative burden imposed on the Reporting Entities to accommodate the data or information request.

2.2. A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the Reporting Entities to accommodate the modified data or information request, and (iii) any other items from Section 1602.2.1 that require updating as a result of the modifications.

3. After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC's evaluation of the comments and recommendations, to the Board of Trustees.

4. In acting on the proposed request for data or information, the Board of Trustees may authorize NERC to issue it, modify it, or remand it for further consideration.

5. NERC may make minor changes to an authorized request for data or information without Board approval. However, if a Reporting Entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require Board approval before they are implemented.

6. Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board of Trustees, an affected party appeals the authorization under this Section 1600 to the Applicable Governmental Authority.

1603. Owners, Operators, and Users to Comply

Owners, operators, and users of the Bulk Power System registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a Reporting Entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the Reporting Entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.

1604. Requests by Regional Entity for Data or Information

1. A Regional Entity may request that NERC seek authorization for a request for data or information to be applicable within the Region of the Regional Entity, either as a freestanding request or as part of a proposed NERC request for data or information. Any such request must be consistent with this Section 1600.

2. A Regional Entity may also develop its own procedures for requesting data or information, but any such procedures must include at least the same procedural

elements as are included in this Section 1600. Any such Regional Entity procedures or changes to such procedures shall be submitted to NERC for approval. Upon approving such procedures or changes thereto, NERC shall file the proposed procedures or proposed changes for approval by the Commission and any other Applicable Governmental Authorities applicable to the Regional Entity. The Regional Entity procedures or changes to such procedures shall not be effective in a jurisdiction until approved by, and in accordance with any revisions directed by, the Commission or other Applicable Governmental Authority.

1605. Confidentiality

If the approved data or information request includes a statement under Section 1602.1.1(v) that the requested data or information will be held confidential or treated as Critical Energy Infrastructure Information, then the applicable provisions of Section 1500 will apply without further action by a Submitting Entity. A Submitting Entity may designate any other data or information as Confidential Information pursuant to the provisions of Section 1500, and NERC or the Regional Entity shall treat that data or information in accordance with Section 1500. NERC or a Regional Entity may utilize additional protective procedures for handling particular requests for data or information as may be necessary under the circumstances.

1606. Expedited Procedures for Requesting Time-Sensitive Data or Information

1. In the event NERC or a Regional Entity must obtain data or information by a date or within a time period that does not permit adherence to the time periods specified in Section 1602, the procedures specified in Section 1606 may be used to obtain the data or information. Without limiting the circumstances in which the procedures in Section 1606 may be used, such circumstances include situations in which it is necessary to obtain the data or information (in order to evaluate a threat to the reliability or security of the Bulk Power System, or to comply with a directive in an order issued by the Commission or by another Applicable Governmental Authority) within a shorter time period than possible under Section 1602. The procedures specified in Section 1606 may only be used if authorized by the NERC Board of Trustees prior to activation of such procedures.

2. Prior to posting a proposed request for data or information, or a modification to a previously-authorized request, for public comment under Section 1606, NERC shall provide the proposed request or modification, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability. The submission to the Commission's Office of Electric Reliability shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information. The submission shall be made to the Commission's Office of Electric Reliability as far in advance, up to twenty-one (21) days, of the posting of the proposed request or modification for public comments as is reasonably possible under the circumstances, but in no event less than two (2) days in advance of the public posting of the proposed request or modification.

3. NERC shall post the proposed request for data or information or proposed modification to a previously-authorized request for data or information for a public comment period that is reasonable in duration given the circumstances, but in no event shorter than five (5) days. The proposed request for data or information or proposed modification to a previously-authorized request for data or information shall include the information specified in Section 1602.2.1 or 1602.2.2, as applicable, and shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information.

4. The provisions of Sections 1602.3, 1602.4, 1602.5 and 1602.6 shall be applicable to a request for data or information or modification to a previously-authorized request for data or information developed and issued pursuant to Section 1606, except that (a) if NERC makes minor changes to an authorized request for data or information without Board approval, such changes shall require Board approval if a Reporting Entity objects to NERC in writing to such changes within five (5) days of issuance of the modified request; and (b) authorization of the request for data or information shall be final unless an affected party appeals the authorization of the request by the Board of Trustees to the Applicable Governmental Authority within five (5) days following the decision of the Board of Trustees authorizing the request, which decision shall be promptly posted on NERC's website.

SECTION 1700 — CHALLENGES TO DETERMINATIONS

1701. Scope of Authority

Section 1702 sets forth the procedures to be followed for Registered Entities to challenge determinations made by Planning Coordinators under Reliability Standard PRC-023. Section 1703 sets forth the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023

1. This Section 1702 establishes the procedures to be followed when a Registered Entity wishes to challenge a determination by a Planning Coordinator of the sub-200 kV circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers (defined as "Registered Entities" for purposes of this Section 1702) must comply with the requirements of Reliability Standard PRC-023.

2. Planning Coordinator Procedures

   2.1 Each Planning Coordinator shall establish a procedure for a Registered Entity to submit a written request for an explanation of a determination made by the Planning Coordinator under PRC-023.

   2.2 A Registered Entity shall follow the procedure established by the Planning Coordinator for submitting the request for explanation and must submit any such request within 60 days of receiving the determination under PRC-023 from the Planning Coordinator.

   2.3 Within 30 days of receiving a written request from a Registered Entity, the Planning Coordinator shall provide the Registered Entity with a written explanation of the basis for its determination under PRC-023, unless the Planning Coordinator provided a written explanation of the basis for its determination when it initially informed the Registered Entity of its determination.

3. A Registered Entity may challenge the determination of the Planning Coordinator by filing with the appropriate Regional Entity, with a copy to the Planning Coordinator, within 60 days of receiving the written explanation from the Planning Coordinator. The challenge shall include the following: (a) an explanation of the technical reasons for its disagreement with the Planning Coordinator's determination, along with any supporting documentation, and (b) a copy of the Planning Coordinator's written explanation. Within 30 days of receipt of a challenge, the Planning Coordinator may file a response to the Regional Entity, with a copy to the Registered Entity.

4. The filing of a challenge in good faith shall toll the time period for compliance with PRC-023 with respect to the subject facility until such time as the challenge is withdrawn, settled or resolved.

5. The Regional Entity shall issue its written decision setting forth the basis of its determination within 90 days after it receives the challenge and send copies of the decision to the Registered Entity and the Planning Coordinator. The Regional Entity may convene a meeting of the involved entities and may request additional information. The Regional Entity shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

6. A Planning Coordinator or Registered Entity affected by the decision of the Regional Entity may, within 30 days of the decision, file an appeal with NERC, with copies to the Regional Entity and the Planning Coordinator or Registered Entity. The appeal shall state the basis of the objection to the decision of the Regional Entity and shall include the Regional Entity decision, the written explanation of the Planning Coordinator's determination under PRC-023, and the documents and reasoning filed by the Registered Entity with the Regional Entity in support of its objection. The Regional Entity, Planning Coordinator or Registered Entity may file a response to the appeal within 30 days of the appeal.

7. The Board of Trustees shall appoint a panel to decide appeals from Regional Entity decisions under Section 1702.5. The panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about PRC-023 and transmission planning and do not have a direct financial or business interest in the outcome of the appeal. The panel shall decide the appeal within 90 days of receiving the appeal from the decision of the Regional Entity and shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

8. The Planning Coordinator or Registered Entity affected by the decision of the panel may request that the Board of Trustees review the decision by filing its request for review and a statement of reasons with NERC's Chief Reliability Officer within 30 days of the panel decision. The Board of Trustees may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. Within 90 days of the request for review under this Section 1702.8, the Board of Trustees may either (a) issue a decision on the merits, which shall be the final NERC decision, or (b) issue a notice declining to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. If no written decision or notice declining review is issued within 90 calendar days, the appeal shall be deemed to have been denied by the Board of Trustees and this will have the same effect as a notice declining review.

9. The Registered Entity or Planning Coordinator may appeal the final NERC decision to the Applicable Governmental Authority within 30 days of receipt of

the Board of Trustees' final decision or notice declining review, or expiration of the 90-day review period without any action by NERC.

10. The Planning Coordinator and Registered Entity are encouraged, but not required, to meet to resolve any dispute, including use of mutually agreed to alternative dispute resolution procedures, at any time during the course of the matter. In the event resolution occurs after the filing of a challenge, the Registered Entity and Planning Coordinator shall jointly provide to the applicable Regional Entity a written acknowledgement of withdrawal of the challenge or appeal, including a statement that all outstanding issues have been resolved.

1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509

1. This Section 1703 establishes the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

2. A Submitting Entity (or Owner if different) aggrieved by the decision of NERC to approve or disapprove an Exception Request or to terminate an Exception with respect to any Element may, within 30 days following the date of the decision, file a written challenge to the decision with the NERC director of compliance operations, with copies to the Regional Entity and the Submitting Entity or Owner if different. The challenge shall state the basis of the objection to the decision of NERC. The Regional Entity, and the Submitting Entity or Owner if different, may file a response to the challenge within 30 days following the date the challenge is filed with NERC.

3. The challenge shall be decided by the Board of Trustees Compliance Committee. Within 90 days of the date of submission of the challenge, the Board of Trustees Compliance Committee shall issue its decision on the challenge. The decision of the Board of Trustees Compliance Committee shall be the final NERC decision; provided, that the Board of Trustees Compliance Committee may extend the deadline date for its decision to a date more than 90 days following submission of the challenge, by issuing a notice to the Submitting Entity, the Owner (if different) and the Regional Entity stating the revised deadline date and the reason for the extension.

4. The Submitting Entity, or Owner if different, may appeal the final NERC decision to, or seek review of the final NERC decision by, the Applicable Governmental Authority(ies), in accordance with the legal authority and rules and procedures of the Applicable Governmental Authority(ies). Any such appeal shall be filed within thirty (30) days following the date of the decision of the Board of Trustees Compliance Committee, or within such other time period as is provided for in the legal authority, rules or procedures of the Applicable Governmental Authority.

Exhibit B

Comments on Proposed Revisions

From:	Colleen Campbell
To:	ROPComments
Cc:	Brian Van Gheem; Ben Engelby; Trey Cross; Jason Marshall
Subject:	Comments - Proposed Revisions to Sections 600 and 900 Personnel Certification, Training & Education
Date:	Thursday, December 22, 2016 3:35:29 PM
Attachments:	ACES Comments - NERC ROP Sec600 and 900 Training & Education.pdf

Good afternoon,

On behalf of Brian Van Gheem, please see the attached comments on the proposed changes to ROP Sections 600 and 900 Personnel Certification, Training and Education.

Thank you for the opportunity to comment.

Best Regards,

Colleen Campbell | Senior Reliability Compliance Specialist

ACES® | 4140 W 99th Street | Carmel, IN 46032

o: (317) 344-7113 | colleen.campbell@acespower.com

Think before you print

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From:	Thomas E Foltz
To:	ROPComments
Subject:	AEP Comments re: Proposed Revisions to the NERC Rules of Procedure, Sections 600 (Personnel Certification) and 900 (Training and Education)
Date:	Thursday, December 15, 2016 8:00:28 AM

American Electric Power appreciates the opportunity to provide input on the proposed revisions to the NERC Rules of Procedure, Sections 600 (Personnel Certification) and 900 (Training and Education), and offers the following comments for consideration.

AEP fully supports the proposed revisions to the NERC ROP Sections 600 & 900. These proposed changes appear to be driven by a desire to move language out of Sections 600 and 900 that are more appropriately housed and maintained in the actual Program Manual itself, allowing the PCGC to better manage the Operator Certification Program & Process.

Respectfully,

Thomas Foltz, PE (State of Ohio)
AEP Reliability Standards Compliance
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From:	Pusztai, Andrew
To:	ROPComments
Cc:	Johnson, Douglas F.; Price, Lauren
Subject:	ATC Comments regarding Proposed Revisions to the NERC Rules of Procedure (Sections 600 and 900) (Due 12/24/16)
Date:	Tuesday, December 20, 2016 10:19:16 AM
Attachments:	Summary_ROP_Revisions_Sections 600 and 900_11092016.pdf Proposed Comments ROP Section 600 and 900 Training & Education.docx
Importance:	High

ATC thanks NERC for the opportunity to submit comments on the subject NERC proposed revisions to the NERC Rules of Procedure (ROPs), Sections 600 and 900. ATC supports the comments from the MRO NERC Standards Review Forum (NSRF) attached and adding a couple comments of our own below. The NSRF comments questions whether the proposed changes are appropriate, while other comments are made to help clarify the ROP proposed changes.

ATC would like clarification on the following, as proposed in the redline of the ROP proposed revisions:

- NERC proposes to consolidate Section 602 and 603 requiring the PCGC to develop a certification program manual. I caution NERC to not eliminate(or revise)the ROP Sections until the certification program manual is developed and approved. This could potentially be identified as a gap to the certification program as defined in the current ROPs.
- Section 901 Redline introduces Item #2 the "ERO functional program requirements". I could not find what or where these exist? NERC should clarify this.

ATC recommends that NERC Legal consider the NSRF comments and clarify areas of concern, including the two comments above.

If any questions, please contact me.

Sincerely,

Andy Pusztai
American Transmission Company
Reliability Policy and Standards Consultant
Work: (262) 506-6913
Cell: (262) 424-4332

Notice of Proposed Revisions to the NERC Rules of Procedure and Request for Comments

NERC Rules of Procedure, Sections 600 (Personnel Certification) and 900 (Training and Education)

Click here for: NERC Rules of Procedure site
Click here for: Summary of Proposed Revisions
Click here for proposed changes: Redlined Text of Proposed Revisions to Rules of Procedure Sections 600 and 900

Proposed Revisions to Rules of Procedure – The North American Electric Reliability Corporation ("NERC") is proposing revisions to currently effective Sections 600 ("Personnel Certification") and 900 ("Training and Education") of its Rules of Procedure ("ROP"). The purpose of these revisions is twofold. First, NERC proposes to clarify the scope of the Personnel Certification Program, the Training and Education Program and the Continuing Education Program. Second, NERC proposes to modernize and align the language of the ROP with current practices of those programs.

NERC requests comments on the proposed revisions to the NERC Rules of Procedure. The 45-day comment period begins November 9, 2016 and ends December 24, 2016.

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

Comments are due December 24, 2016, and must be submitted electronically to ROPcomments@nerc.net. NERC intends to submit these changes to the NERC Board of Trustees for consideration at its February 2017 meeting. For more information or assistance, please contact Nina Johnston

Section 601 Item 1 - …provide the mechanism to determine system operators' essential knowledge relating to NERC Reliability Standards…

Section 606 Item 1 – The PCGC shall develop exams to

(1) evaluate individual competence in a manner that is objective~~,~~ and fair to all candidates, and

(2) ~~to attain~~ determine essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations.

Section 902 Item 2 – NERC shall perform periodic audits of NERC-approved continuing education Providers and activities to monitor that the approved Providers and activities satisfy NERC continuing education requirements.

Section 902 Item 3 - NERC shall develop and maintain a~~n~~ multi-layer review process for disputed application reviews, interpretations of guidelines and standards, probation or suspension of NERC-approved Provider status, ~~or~~ and Continuing Education Hour disputes

From:	Terry Bilke
To:	ROPComments
Subject:	Comments on NERC Rules of Procedure sections 600 and 900
Date:	Wednesday, December 21, 2016 10:49:20 AM

MISO agrees with the comments drafted by the MRO NSRF.

We believe the Rules of Procedure regarding System Operator Certification and Continuing Education remain as is, in particular those items dealing with appeals, hearings, and due process. The NERC Rules of Procedure are the proper place for outlining due process on ERO governance issues.

Additionally, as the PCGC's program documents can impact operator employment as well as Registered Entity compliance, they should be subject to notice and public comment.

Finally, we believe there is need for dialog with the industry on improvements to the current CEH and Operator Certification programs. With the advent of the PER standards, the credential should be good for at least 5 years. We also have concerns with recent revocations of long-standing learning activities.

Terry Bilke
MISO
P.O. Box 4202
Carmel, Indiana 46032-4202
317-249-5463

FROM: Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF)

TO: ROPcomments@nerc.net

Comments:

NERC Rules of Procedure, Sections 600 (Personnel Certification) and 900 (Training and Education)

The Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) has concerns with the proposed changes to the Rules of Procedure regarding Operator Certification. There are several deletions of policy and due process items related to Operator Certification and it appears the intent is to move them to the "System Operator Certification Program manual".

The Rules of Procedure are the appropriate place for due process. There are well over 300 references to appeals in the Rules. The background information for the proposed changes gives no clear reasoning why the proposed changes are necessary and what issues need to be fixed.

While the draft Rules say the NERC Board approves changes to the program manual, there is no mention about how changes to the manual are handled.

Just as the Rules of Procedure and nearly every official NERC process go through public comment, it seems that changes to the program manual should go through a public comment before going to the NERC Board.

In short, we offer the following recommendations:

1. The current wording related to appeals dealing with Operator Certification should be maintained in the Rules of Procedure.
2. There should be a statement at the end of section 602 that all proposed changes to the System Operator Certification Program manual be publicly noticed, with opportunity for comment.

From:	Watkins, Jeffrey
To:	ROPComments
Subject:	Comments on NERC Rules of Procedure sections 600 and 900
Date:	Wednesday, December 21, 2016 6:46:14 PM
Attachments:	image001.png NERC CE Program Reevaluation DEC clean.pdf

NV Energy proposes the following comments:

There are several deletions of policy and due process items related to Operator Certification and it appears the intent is to move them to the "System Operator Certification Program manual". While the draft Rules say the NERC Board approves changes to the program manual, there is no mention about how changes to the manual are handled. Just as the Rules of Procedure and nearly every official NERC process go through public comment, it seems that changes to the program manual should go through a public comment before going to the NERC Board.

In short, we offer the following recommendations:

1. The current wording related to appeals dealing with Operator Certification should be maintained in the Rules of Procedure.
2. There should be a statement at the end of section 602 that all proposed changes to the System Operator Certification Program manual be publicly noticed, with opportunity for comment.

In addition,
We would also like to support comment made by PJM (attached) regarding a re-evaluation of the NERC CE Program.

Thanks

Jeff Watkins, P.E.
Sr. NERC Compliance Engineer
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****
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****

From:	DiCaprio, A.M.
To:	ROPComments
Cc:	"*SRC"; Boyle, Glen; Sitarchyk, Mike
Subject:	Comments on NERC Rules of Procedure sections 600 and 900
Date:	Friday, December 23, 2016 1:22:46 PM
Attachments:	NERC CE Program Reevaluation DEC clean.pdf

The RTO/ISO Standards Review Committee Group of IESO, ISONE, PJM, MISO, SPP, ERCOT and CAISO submit the following comments:

The SRC agrees that changes are needed to the NERC Rules of Procedure (ROP) related to Sections 600 (Personnel Certification) and 900 (Training and Education). However it cannot support the changes as written or reasons given for making them. We will outline these concerns here as well as provide potential solutions in the attached whitepaper.

The NERC Personnel Certification Program began in 1998 and the NERC Continuing Education (CE) Program in 2004. Both programs predate the implementation of mandatory standards in 2007. Entities have been subject to standards that cover both certification (PER 003) and training (PER 005) for some time now. While we agree changes are needed "to clarify the scope of" these programs, the proposed changes do nothing to address the existence of these standards but seem to simply perpetuate the programs much as they have been implemented from their inception.

Further, we do not think it is appropriate to remove "requirements in the NERC ROP" that could have any impact on an entity's compliance with mandatory standards to committee charters and manuals. Even though these documents are "reviewed annually for updates and revisions are approved by the Board of Trustees", this does not provide the industry with the same transparency and opportunity to comment on new or changed requirements that could impact compliance with PER 003 and PER 005.

We feel any additional requirements related to certification or training and education should be developed the same way the requirements for PER 003 and PER 005 were; through the existing standard development process outlined in Section 300 of the NERC ROP. This ensures the "essential principles" of Section 304 of the ROP are adhered to (Openness, Transparency, Consensus-building, Fair Balance of Interest, Due Process, and Timeliness).

To continue to develop requirements outside this process may violate the principle or spirit of Section 401.8 of the ROP where entities are not to be subject to multiple enforcement actions. This especially should be considered with the NERC Continuing Education Program. Under PER 005, training providers already have requirements to implement a systematic approach to training (SAT) and have their programs regularly audited. Separate but parallel, the NERC Continuing Education program has its own requirements and audits. As outlined in the whitepaper, these requirements and audits are inferior and may actually work against the implementation of an entity's PER 005 SAT training program.

We recommend removal of Section 902. While there certainly could be a role for an industry committee to share best practices related to training, this could likely be incorporated into Section

901. It would also be inappropriate to move the existing language of Section 902 to committee charters or NERC manuals. Such language includes; “approving activities and entities”, “develop and implement … program requirements”, “perform periodic audits”, “oversee … Providers and activities”, “develop and maintain a process for ... interpretations of guidelines and standards, probation or suspension of NERC-approved Provider status”. With the existence of PER 005, such activities are already covered under Sections 300 and 400 of the NERC ROP.

For the NERC Certification Program, we agree with the continuing role of the Personnel Certification and Governance Committee (PCGC) to create and administer the certification exams that entities use to be compliant with PER 003. Therefore, we agree with most of the changes made to Section 600. However, we do not feel the ROP, committee charter, or certification program manual should contain references to the NERC CE program, CEHs, and re-certification. We feel it is time to re-evaluate how credential maintenance or re-certification is handled. The current tie of the Certification Program to the CE Program did not always exist, but was put in place in 2004 to encourage operator training at a time when there was no mandatory training standard. We feel there are other options; our recommended approach is detailed in the attached whitepaper.

NERC Rules of Procedure

December 8, 2016 Posting

SPP Standards Review Group Comments

Section 600

In Section 601, Part 1, we suggest including the term "guidelines" in the proposed language as follows: 1. provide the mechanism to determine system operators essential knowledge relating to NERC Reliability Standards, and guidelines as well as principles of Bulk Power System operations;

Additionally, we suggest that the term "Bulk Electric System" in the first sentence of Section 601 be replace with the term "Bulk Power System" for consistency.

Section 606

The summary proposes that section 606 is to clarify the PCGC's role and responsibilities pertaining to the integrity of the certification exam. However, it's unclear how the PCGC intends to provide more structure to this process. Can we assume that the program manual will provide more detail on how the policies and procedures developed will ensure success for this program? We would ask NERC to provide more detail on how the PCGC plans to accomplish their goals.

Section 900

We suggest capitalizing the term "Reliable Operation" in section 901 since the proposed language is referring to the Bulk Power System. Reliable Operation is a defined term in the NERC Glossary of Terms.

From:	Crews, Curtis
To:	ROPComments
Cc:	Coyne, Rachel; Andrea Koch; Landin, Yvette; Frosch, Colleen; Trion King
Subject:	Comments on NERC Rules of Procedure sections 600 and 900
Date:	Wednesday, December 21, 2016 4:08:31 PM

Hello,

Most of this does not pertain to Texas RE directly but we recently had some questions from Registered Entities regarding this ROP proposal.

There is nothing in the ROP regarding changes to the Manual mentioned. It would be good to place some expectations about periodicity of reviews and process for comments. This may be managed by the PCGC but the Manual is not mentioned in the PCGC Charter (nor is there a mention of a review process specifically).

System Operator is a defined term. It would be better to maintain consistency between the ROP and Glossary when using terms.

Please maintain consistency in references to the Program (e.g. “NERC Personnel Certification Program”, “Personnel Certification Program”, “activities for the program”, “pursuant to the program”, “System Operator Certification Program”, “certified in the programs”). Note that the current PCGC Charter calls this the “System Operator Certification Program”. Will the Charter be updated to reflect the ROP changes?

Please maintain consistency in references to the Program Manual (e.g., “System Operator Certification Program manual”, “certification program manual”)

Not sure if there is consistency in the terms “Certification Credential” in Section 601 versus “Credential” in Section 602.

In section 607 Does “passed” not equal “certified”? In Section 601 it states “award the system operator Certification Credential to individuals who pass the exam”. Are there examples of multiple test types that an individual may get a single Certification Credential?

Section 609 discusses what the PCGC shall adhere to, so, how would they know about conduct deemed harmful or inappropriate? What mechanisms are in place to provide feedback to the PCGC on System Operators?

Thanks

Curtis Crews, PE
Director, Compliance Assessments
Texas Reliability Entity, Inc.

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O: (512) 583-4989 | C: (512) 913-9964
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www.texasre.org

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Proposed Comments

NERC Rules of Procedure, Sections 600 (Personnel Certification) and 900 (Training and Education)

WAPA Operations Training Departments in Rocky Mountain Region (RMR), Sierra Nevada Region (SNR), and Upper Great Plains Region (UGP) have a consensus opinion regarding NERC Rules of Procedure, Sections 600 (Personnel Certification) and 900 (Training and Education).

The comments are consistent with those provided MRO (Proposed Comments ROP Section 600 and 900 Training Education), specifically with regard to the failure to address a process wherein changes to the "System Operator Certification Program manual" are handled. The recommendation presented by MRO to address this concern is; *"There should be a statement at the end of section 602 that all proposed changes to the System Operator Certification Program manual be publicly noticed, with opportunity for comment."*

Although we do agree that a documented process that includes proposed changes to the System Operator Certification Program manual be publicly noticed with adequate opportunity for comment, we are less concerned with where the process resides.

Therefore, the proposed comment is to:

Include a statement at the end of section 602 (as MRO recommends) ***or*** *include a documented process within the NERC Board approved System Operator Certification Program manual to ensure changes to this document will require public notice and an adequate period to allow for comment on said changes.*

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Federal Energy Regulatory Commission

NEWS RELEASE

August 10, 2017

News Media Contact
Mary O'Driscoll | 202-502-8680

FERC Set to Resume Open Meeting Schedule

The Federal Energy Regulatory Commission (FERC) announced today it will resume its monthly open meeting schedule in September, with a meeting set for 10 a.m. Wednesday, September 20, 2017, in the Commission Meeting Room at FERC's Washington, D.C., headquarters.

FERC Chairman Neil Chatterjee said that with the swearing-in today of Commissioner Robert Powelson, FERC has restored the quorum it lost in February, and the Commission will soon begin voting notationally on the orders that have been held up since then.

The Commission has a continuing responsibility to carry out its regulatory obligations under the Federal Power Act, Natural Gas Act, and Interstate Commerce Act, among other statutes, so without a quorum, FERC staff has been acting under limited delegated authority. That delegation period, which began February 4, ends 14 days following the date the quorum is re-established.

R-17-27

(30)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Generator Trip While Performing Frequency Response

Primary Interest Groups
Generator Operators (GOPs)
Generator Owners (GOs)
Balancing Authorities (BAs)
Reliability Coordinators (RCs)

Problem Statement
Two generating units were responding to a large frequency excursion when they tripped off-line on low boiler furnace pressure.

Details
Two units (units 1 and 3) of a three-unit coal plant were operating at about half load when 1500 MW of generation tripped off elsewhere. The interconnection frequency dropped to 59.79 Hz (see Figure 1 below).

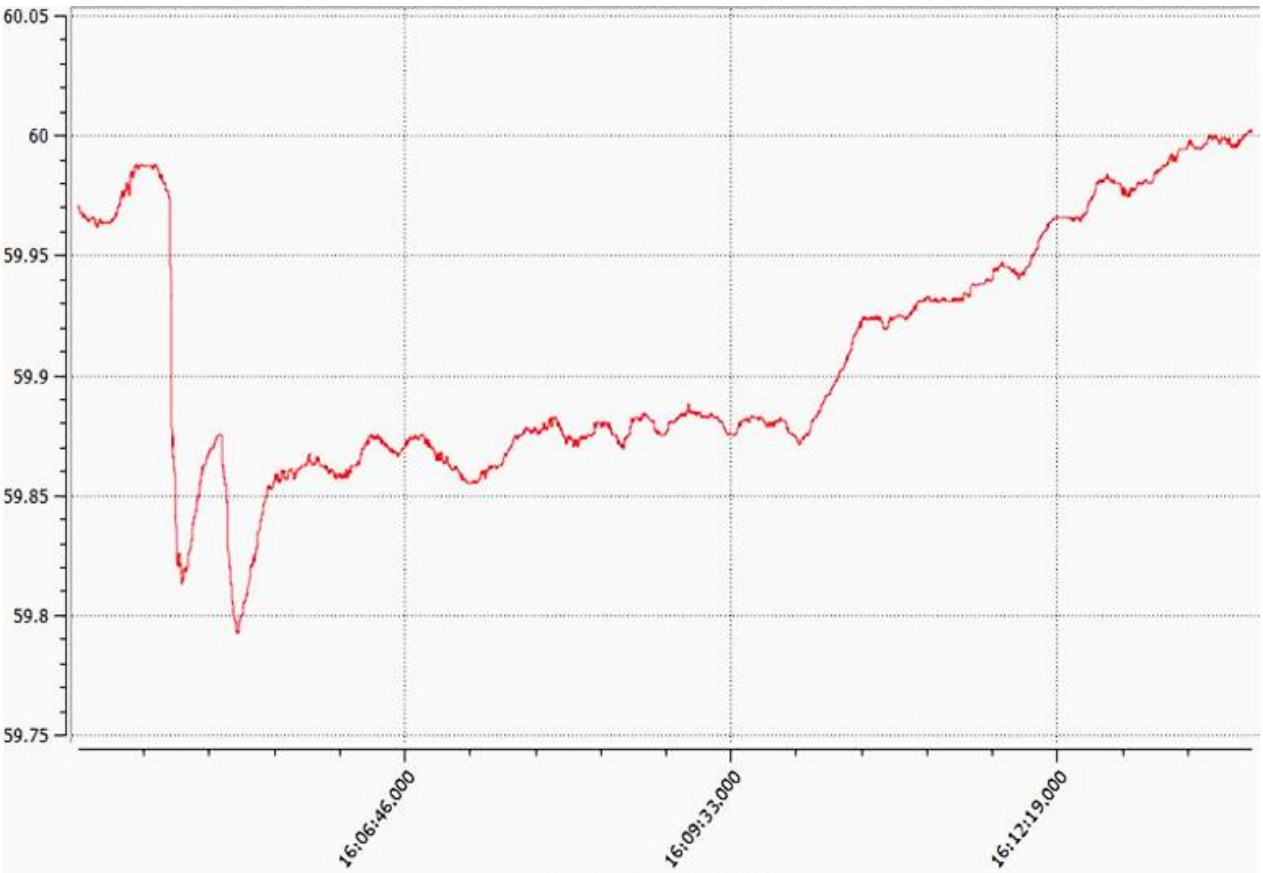

Figure 1: Interconnection Frequency

In response to the dip in frequency, both operating coal units rapidly increased their output. Unit 1 responded with a 205 MW/minute ramp rate while unit 3 responded with a 169 MW/minute ramp rate. The induced draft (ID) and forced draft (FD) fans did not respond in an appropriately coordinated manner with the increased load demand, resulting in low furnace pressure. In less than 15 seconds after the frequency dip, both of these units tripped offline due to low boiler furnace pressure (see Figure 2 below).

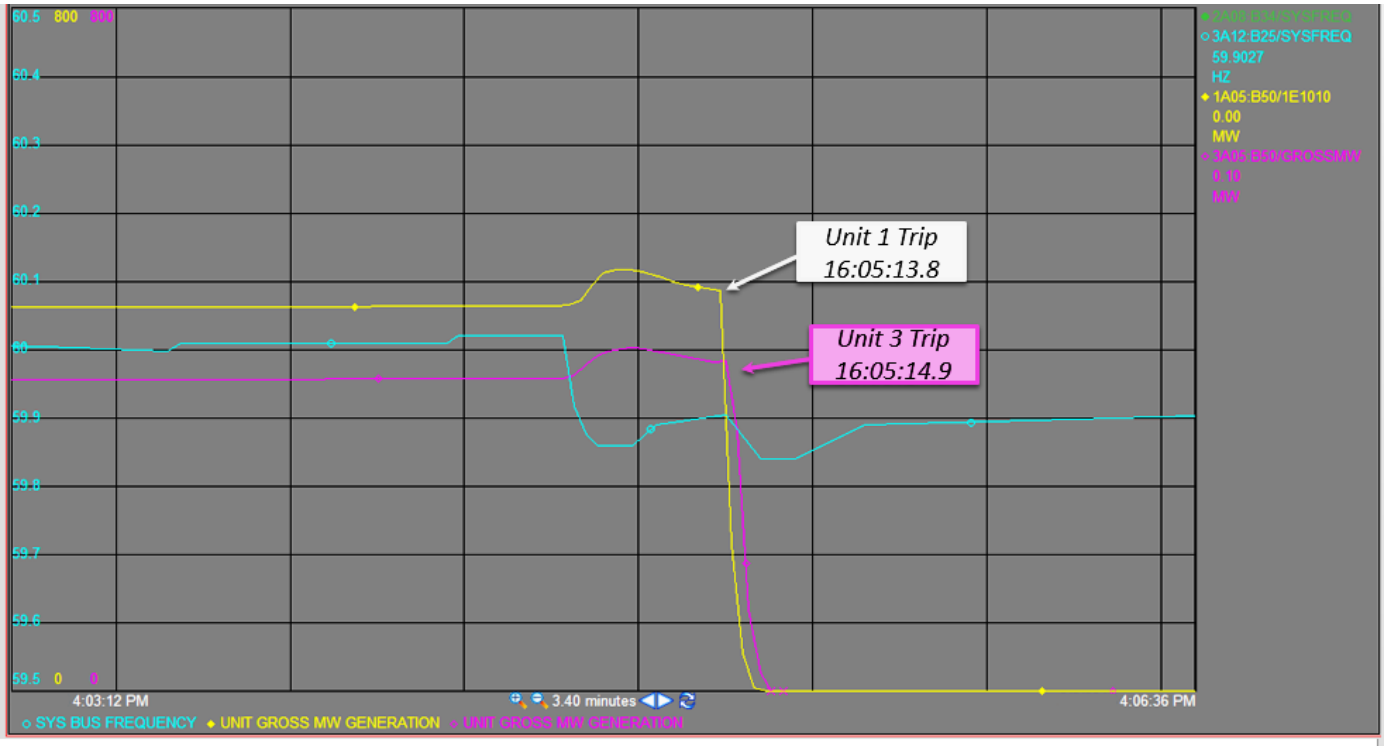

Figure 2: Low Boiler Furnace Pressure Trips

The Generator Operator thought the units should have been able to ride through this frequency event without tripping and instead assist the system in recovering frequency as they have done in the past. In investigating the unit trips with the original design engineer and distributed control system (DCS) vendor, it was determined that the accumulation of plant modifications and incremental tuning (addressing many isolated issues over time) changes during the past fifteen years had altered plant response. The DCS was no longer "in tune" with the physical plant.

This was a configuration management issue. Configuration management involves keeping the physical system (what is *really* there), the documented system (what is *said* to be there), and the requirements of the system (what is *supposed* to be there) in sync at all times (see Figure 3).

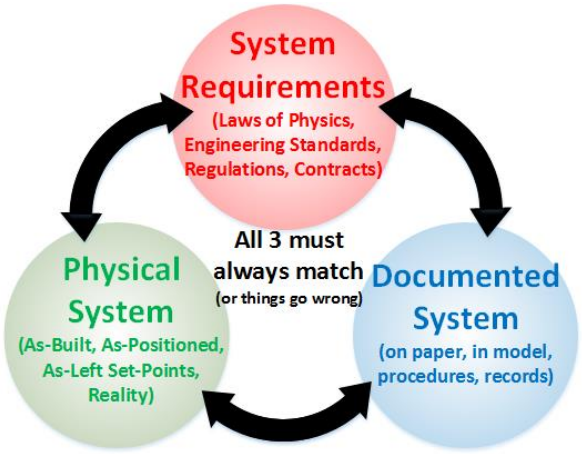

Figure 3: Configuration Management

"Physical" refers to the actual equipment, the actual settings, positions, and conditions. "Documentation" refers to the design drawings, operation and maintenance procedures, and records. "Requirements" may be engineering standards, the laws of nature, contracts, or regulatory requirements. When a change is made to the requirements, the documentation and the physical aspects must be adjusted to match. If the physical does not match the requirements, equipment failures, performance issues, or legal issues are likely to emerge. If the documentation does not match the physical, operators may run into problems with procedures and drawings, maintenance may go awry, and engineers may make wrong assumptions when attempting to design a new modification.

Corrective Actions

The Generator Owner consulted with the vendor and original design engineer to establish whether or not the unit trips were appropriate.

The stroke times on FD and ID fans were captured. It was found that their control curves needed to be modified to align with the physical system changes that had occurred over time to improve stability.

The GO worked with the DCS vendor to schedule load ramps and testing to further tune control curves for the fans and other equipment. This was similar to performing an initial control system commissioning. The DCS tuning cost was less than the startup fuel costs that would have been realized as a result of each of the unnecessary unit trips. This provides a reasonable cost/benefit case for the tuning.

Lesson Learned

Accumulated effects of plant modifications and incremental tuning changes may significantly alter plant response over time. Eventually, the digital model in a DCS may no longer correspond to physical reality or system requirements.

It is cost effective to obtain unit load data and perform baseline "re-tuning" every 5-10 years (depending on frequency of modifications) or as part of any major modification project.

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 #:	20170601
Date Published:	June 20, 2017
Category:	Generation 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

Loss of Wind Turbines due to Transient Voltage Disturbances on the Bulk Transmission System

Primary Interest Groups
Balancing Authorities (BAs)
Transmission Operators (TOPs)
Generator Operators (GOPs)
Generator Owners (GOs)
Reliability Coordinators (RCs)

Problem Statement
Voltage disturbance events on the transmission system in Australia and Texas have highlighted concerns with voltage ride through and in some wind turbine control system parameters.

Details

South Australia Blackout Event[1]

On September 28, 2016, five transmission system faults occurred within a period of 87 seconds, leading to six voltage disturbances on the South Australian (SA) grid. The SA grid has one synchronous connection to the rest of the Australian National Electricity Market grid through a 275 kV double-circuit, single-tower ac transmission line (the "tie line"). At the time of the event, total load in SA was 1826 MW with 330 MW being provided by a few synchronous generators, 883 MW coming from wind, 114 MW being imported on a DC interconnector, and 499 MW being imported on the tie line. Investigations showed that there was a total sustained reduction of 456 MW of wind generation across nine wind plants, plus further transient reductions of 42 MW during each of the voltage disturbances. The sudden loss of 456 MW of generation increased import flows on the tie line, and the increased flow caused the protection system to disconnect the tie line to avoid damage, resulting in system separation from the rest of the Australian grid. The combined loss of the tie line and wind generation created a sudden supply deficit on the order of 50 percent of the pre-disturbance load. This large supply deficit resulted in very rapid system frequency decrease to below 47 Hz (Australia operates at nominal 50 Hz), causing the remaining generation and the DC interconnector to trip as expected. This resulted in the blackout of the South Australian grid.

ERCOT Events

Although outcomes have not been as severe as was observed in the Australian event, ERCOT has observed several situations where line faults or bus faults resulted in temporary loss of wind generation. These events provide additional understanding of the causes and recommended actions.

- Event 1: A 138 kV multiphase bus fault resulted in seven voltage disturbances within a ten-minute period. Investigations showed a total reduction of 475 MW of wind generation across nine wind plants during the event (approximately 56 percent of their pre-event output). The loss of generation,

[1] AEMO Report "Black System South Australia September 28, 2016" published March 2017

in addition to the loss of a static var compensator in the area, caused a low-voltage condition on the local transmission system. This resulted in the operation of under voltage load shed (UVLS) relays that disconnected 92 MW of firm load.

- Event 2: A 138 kV line fault caused a low-voltage excursion, resulting in the loss of 342 MW of wind generation across seven wind plants (a loss of approximately 36 percent of pre-event output). Five of these wind plants were connected to the 345 kV transmission grid. System frequency dipped to 59.905 Hz as a result of the loss of generation and recovered to 60 Hz in less than three minutes.
- Event 3: A 345 kV line fault caused a single-phase low voltage excursion (see Figure 1), resulting in the loss of 343 MW of wind generation across seven wind plants (a loss of approximately 48 percent of the pre-event output). Phasor measurement unit (PMU) data in the vicinity of the disturbance showed a voltage oscillation between 0.78 and 1.07 per-unit for less than 0.5 seconds. System frequency dipped to 59.864 Hz as a result of the loss of generation and recovered to 60 Hz in less than four minutes.

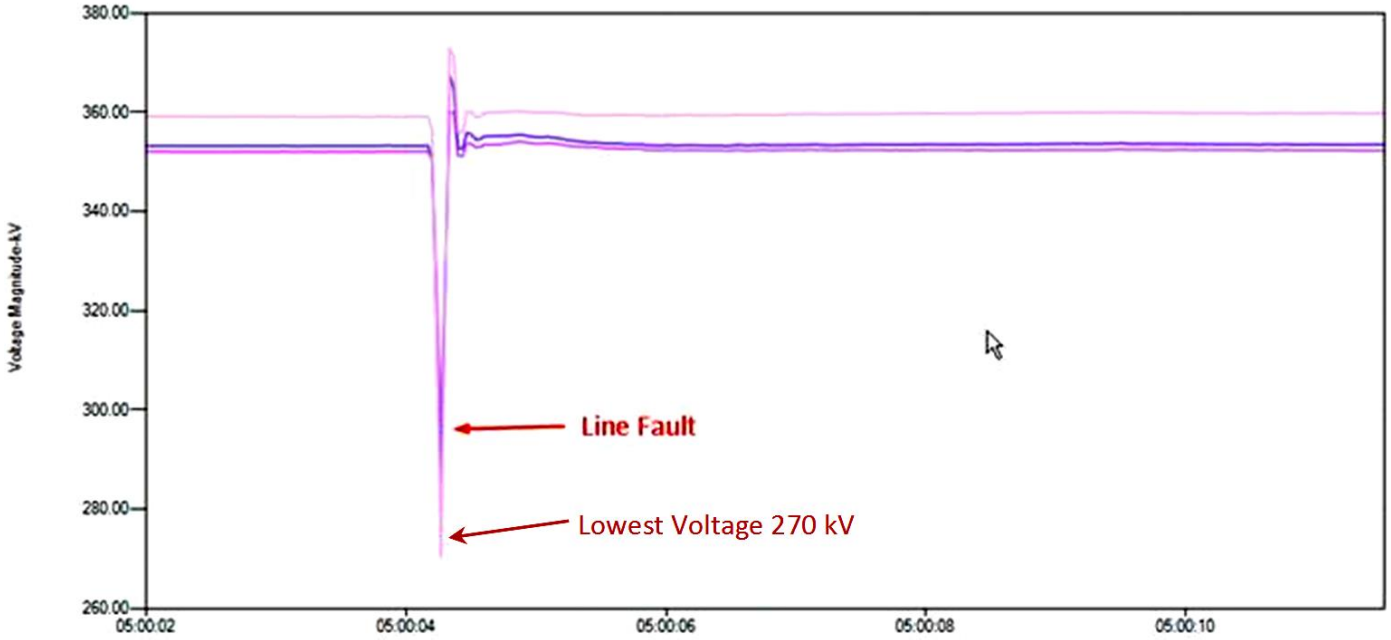


Figure 1 (Event 3)

- Event 4: A 69 kV bus fault caused a low-voltage excursion, resulting in the loss of 230 MW of wind generation across seven wind plants (a loss of approximately 85 percent of the pre-event output). All of these wind plants were connected to the 138 kV transmission grid. PMU data from the 138 kV system in the area showed a low-voltage magnitude of 0.86 per unit and recovery to pre-event magnitude in 0.2 seconds.
- Event 5: A 138 kV line fault caused a low voltage excursion, resulting in the loss of 404 MW of wind generation across six wind plants (a loss of approximately 53 percent of the pre-event output). Five of these wind plants were connected to the 345 kV transmission grid. PMU data from the 345 kV system in the area showed a voltage oscillation between 0.84 and 1.09 per-unit for approximately

0.2 seconds (see Figure 2). System frequency dipped to 59.902 Hz as a result of the loss of generation and recovered to 60 Hz in five minutes.

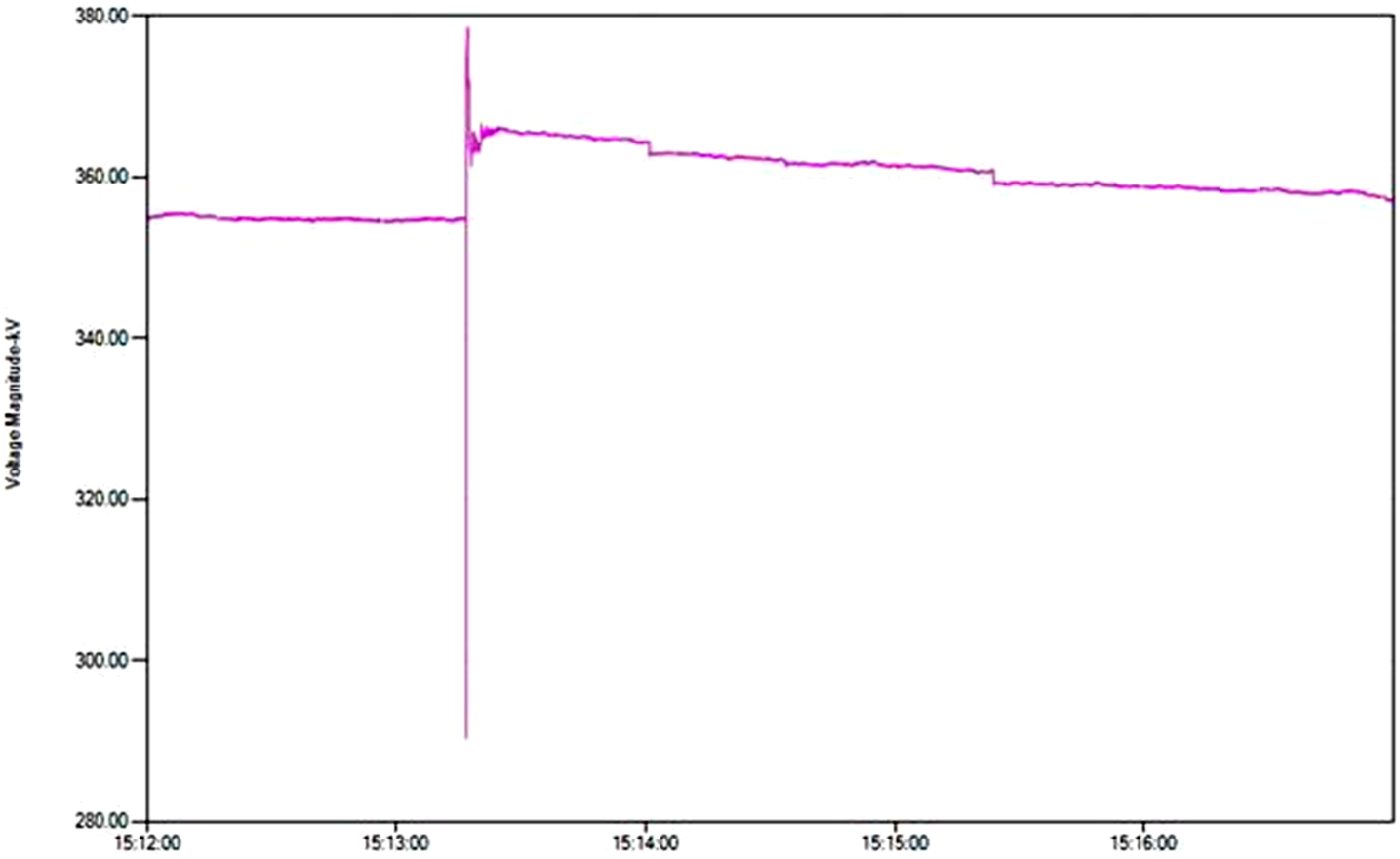


Figure 2 (Event 5)

Corrective Actions

The following corrective actions were taken by the Australian Energy Market Operator (AEMO) after the September 28, 2016 event:

- Of the 13 wind plants that were on-line, nine did not ride through the six voltage disturbances during the event. In the days following, AEMO identified this issue and reclassified the simultaneous trip of these wind plants as a credible contingency.
- AEMO then worked with each of the operators of these wind plants and determined that their voltage ride-through settings were set to disconnect or reduce turbine output when between three and six voltage ride-through events were detected within a given time frame. The investigations also found that information on the control system and these parameter settings were not included in the information provided to AEMO during the registration process prior to interconnection.
- The wind plant operators and the turbine manufacturers proposed improved voltage ride-through settings for consideration by AEMO. As the wind plants were reconfigured with these new settings, the plants were removed from the contingency group and returned to normal operation.

- During a subsequent event on March 3, 2017,[2] the failure of a 275 kV capacitor voltage transformer resulted in a series of three transmission voltage disturbances within a 1.6 second period. All of the wind plants in the South Australia grid rode through the transmission faults with no identifiable reduction in output, indicating that the changes made since the September 28, 2016, event were successful in improving the ride-through characteristics of the wind plants.

The following issues were noted by wind plant owners following the ERCOT events:

- During Event 2, one wind plant owner noted that 12 turbines tripped due to the failure of the wind turbine auxiliary uninterruptible power supplies (UPS) devices. UPS devices provide clean power and ride-through power for critical wind turbine auxiliary controls such as blade pitch, nacelle yaw, and brake control. UPS devices may also provide power for SCADA, metering, and other controls. The most frequent UPS failures are battery failures and environment-related (humidity, temperature, vibration) circuit board failures. The owner is investigating the cause of these particular UPS failures.
- One wind plant owner noted that 11 turbines tripped due to failed crowbar components in the wind turbine during Event 2. (See Attachment 1 for an explanation of crowbar circuit use in wind turbines). The facility owner updated the wind turbine semiannual maintenance process to add inspections of the "Smart Crowbar" circuits. During Event 5, 29 turbines tripped that did not have functioning "Smart Crowbar" hardware, meaning that they will only ride through voltage excursions within +/-10% of nominal voltage.
- During Event 1, wind plant owners noted that 130 turbines tripped due to the repeated voltage fluctuations during a particular event. The magnitude of the individual voltage disturbances were within the "no trip zone" of regional low-voltage ride-through requirements; however, the turbines tripped due to voltage ride-through parameters that were set to disconnect or reduce turbine output when a specified number of voltage excursions were detected within a given time frame (note that Figure 3 on the next page comes from four-second data sampling, so the actual magnitude of fluctuations may be greater than indicated). The rationale for this setting was to prevent damage to the turbine when there was insufficient recovery time between the voltage excursions. This is similar to the experiences reported by AEMO during the September 28, 2016, South Australia event.

[2] AEMO Report "Fault at Torrens Island Switchyard and Loss of Multiple Generating Units on 3 March 2017" published March 2017

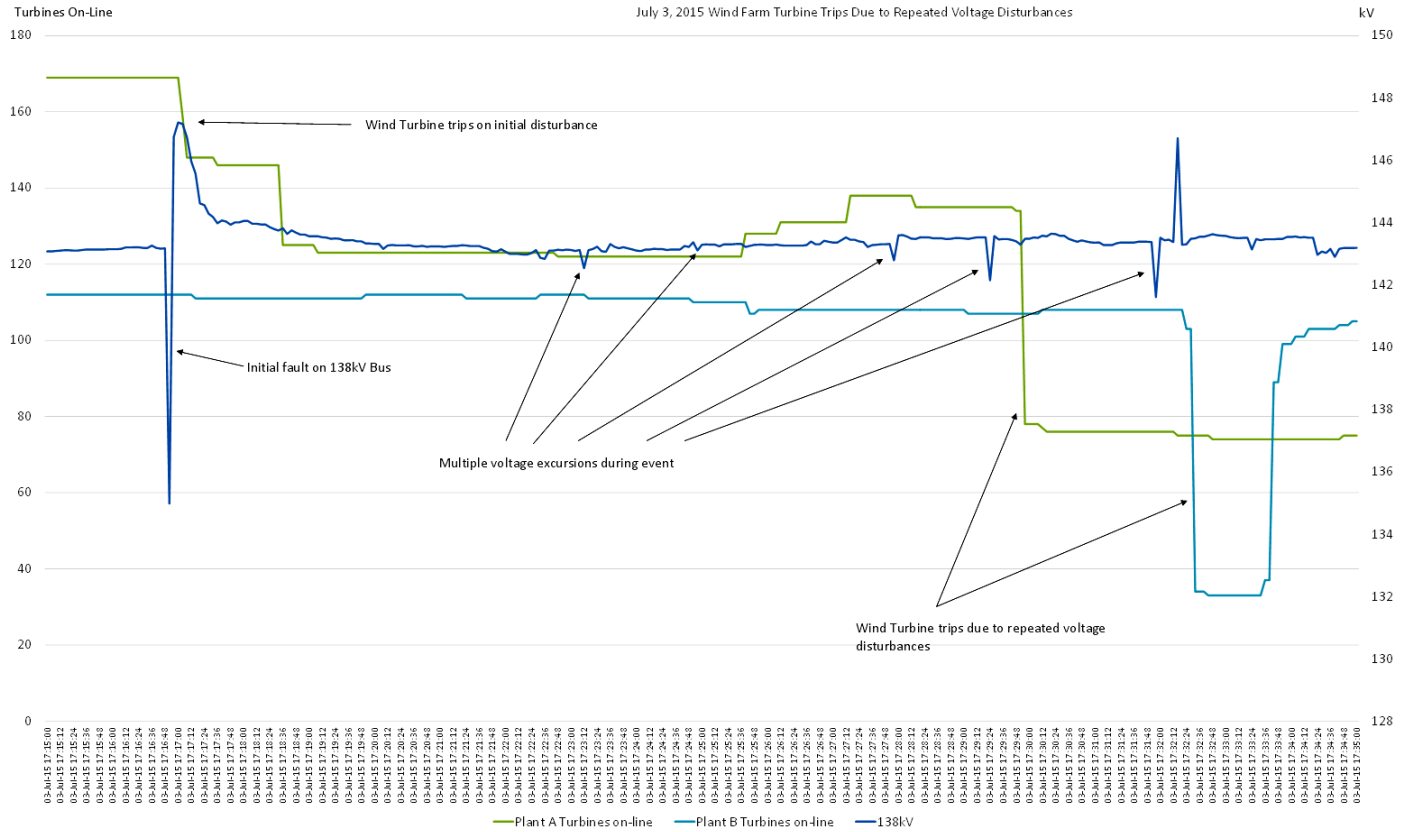


Figure 3

- During Event 4, multiple wind plant owners indicated that the voltage ride-through tolerance for their turbines was insufficient for the magnitude of the voltage disturbance. Those ride-through capabilities ranged from:
  - Less than 0.80 per-unit for 0.08 to 0.2 seconds
  - Between 0.80 and 0.90 per-unit for up to 60 seconds

As noted above, ERCOT Event 1 shows similarities to the South Australia event in that it was related to repeated, rapid voltage fluctuations. The other ERCOT events, while more general in nature, provide additional support for the Lessons Learned that follow.

Lesson Learned

- Wind generation owners should review and verify the voltage ride-through capabilities of their equipment, clearly communicate those capabilities to their BA and connected TOPs, and ensure that the models provided to the BA and TOPs correctly reflect those capabilities.
- If BAs and TOPs are notified by the wind generation owners that units lack ride through capability, BAs and TOPs should communicate to their RC and BAs, TOPs, and RC should consider in their daily resource plan the potential for the loss of these resources during transmission faults on the power system. BAs, TOPs, and RCs should take appropriate mitigating measures.

- Wind generation owners should review and verify that UPS and "Smart Crowbar" systems within the wind turbines are maintained and functioning properly.
- High speed PMU data is critical for visibility into the magnitude of voltage disturbances related to the loss of wind turbines (or grid resources of any type).

References:

- AEMO Report "Black System South Australia September 28, 2016"
- AEMO Report "Fault at Torrens Island Switchyard and Loss of Multiple Generating Units on 3 March 2017"

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:

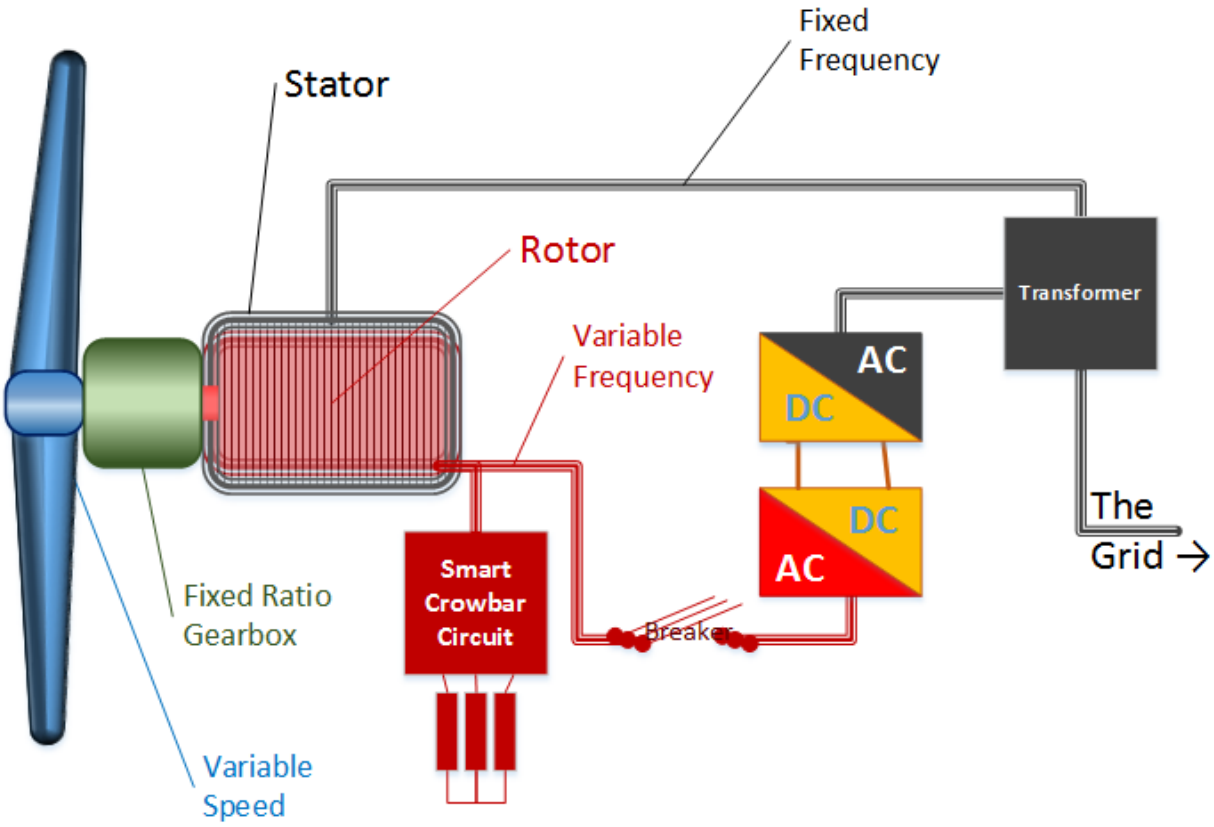
NERC – Lessons Learned (via email)	David Penney (via email) or (512) 583-4958

Source of Lesson Learned:	Texas Reliability Entity
Lesson Learned #:	20170701
Date Published:	July 11, 2017
Category:	Generation 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.

Attachment 1:
Simplified DFIG Wind Turbine diagram for explaining Crowbar Circuit use

Most recently built wind turbines use Doubly Fed Induction Generators (DFIG) that have their stator windings connected directly to the grid, making the rotor winding susceptible to high currents induced during grid faults. The back-to-back converter subsystem (variable-AC to DC to fixed-AC) is very sensitive to over-currents.



Various methods have been used to provide low voltage ride-through capability and some ability to contribute to voltage support during and after grid faults. One method is to dump excess energy with a crowbar system, which intentionally shorts out the rotor windings through large resistors when predetermined thresholds of measured parameters are reached, usually based on the DC-link voltage level in the back-to-back conversion system. In addition, a combination of blade pitch control and braking is typically used to quickly reduce the mechanical energy input.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Industry Recommendation

Loss of Solar Resources during Transmission Disturbances due to Inverter Settings

Initial Distribution: June 20, 2017

NERC identified a potential characteristic exhibited by some inverter-based resources, particularly utility-scale solar photovoltaic (PV) generation, which reduces power output during fault conditions on the transmission system. An example of this behavior has been observed during recent BPS disturbances, highlighting potential risks to BPS reliability. With the recent and expected increases of utility-scale solar resources, the causes of this reduction in power output from utility-scale power inverters needs to be widely communicated and addressed by the industry. The industry should identify reliability preserving actions in the areas of power system planning and operations to reduce the system reliability impact in the event of widespread loss of solar-resources during faults on the power system.

For more information, see the 1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report

About NERC Alerts >>

Status:	**Acknowledgement Required by Midnight Eastern on June 27, 2017** **Reporting Required by Midnight Eastern on August 31, 2017**
	PUBLIC: No Restrictions **More on handling >>**
Instructions:	This recommendation provides specific actions NERC registered entities should consider taking to respond to a particular issue. Pursuant to Rule 810 of NERC's Rules of Procedure, NERC registered entities shall 1) acknowledge receipt of this advisory within the NERC Alert System, and 2) report to NERC on the status of their activities in relation to this recommendation as provided below. For U.S. entities, NERC will compile the responses and report the results to the Federal Energy Regulatory Commission.

	This recommendation is not the same as a Reliability Standard and your organization will not be subject to penalties for a failure to implement. Issuance of this recommendation does not lower or otherwise alter the requirements of any approved Reliability Standard or excuse the prior failure to follow the practices discussed in the recommendation if such failure constitutes a violation of a Reliability Standard.
Distribution:	**Initial Distribution:** Balancing Authority, Generator Operator, Generator Owner, Reliability Coordinator, Transmission Operator, Transmission Owner **Who else will get this alert? >>**
Primary Interest Groups:	Generation Engineering, Generation Operations, System Operations—Transmission Engineering, System Operators, System Operators—System Protection, Transmission Planning, Reliability Coordinator, Transmission Service Provider, Transmission Planner, Planning Coordinator.

Recommendations:

All recipients are advised to review the 1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report for more technical information and detailed description of the behavior of inverters during abnormal system conditions regarding these recommendations.

Recommendation Number. **1:** Generator Operators and Generator Owners should ensure that your installed inverter controls will not trip due to an erroneous instantaneous frequency measurement during transients on the power system.

Recommendation Number 2: If inverters are identified as among those that momentarily cease to inject current for voltages above 1.1 per unit or below 0.9 per unit during abnormal voltage conditions, Generator Operators and Generator Owners should ensure the time to restore output of the inverter to the state prior to the abnormal voltage conditions is as soon as practical but no greater than five (5) seconds. Inverters may continue producing real and reactive power outside of the ride through operation conditions defined by PRC-024-2 unless other actions are required as part of a special protection scheme, to protect the inverter from damage, or to isolate the faulted equipment directly connected to the inverter.

Recommendation Number 3: If the equipment identified in recommendations 1 and 2 are left unmitigated, Reliability Coordinators and Balancing Authorities should identify which inverter based plants, in the operating area, are unmitigated and consider in their daily resource plan the potential for the loss of these resources during transmission faults on the power system. Reliability Coordinators and Balancing Authorities should take appropriate mitigating measures.

Recommendation Number 4: Generator Operators and Generator Owners should provide their responses to the questions in this alert for each plant in service to NERC and to their Reliability Coordinator, Balancing Authority, and Transmission Operator for each respective site(s) area where the plant is located.

As required by the NERC Rules of Procedures, NERC registered entities are required to:

- Acknowledge receipt of this advisory within the NERC Alert System.
- Review and complete the Reporting Instructions below.

Reporting Instructions:

Initial acknowledgement of receipt is required by **June 27, 2017 Midnight Eastern** via the NERC Alert System. Responses to the questions below are required to be submitted via the NERC Alert System by **August 31, 2017 Midnight Eastern**. Once a response has been submitted follow-up or update responses will not be required.

All applicable registered entities (GO, GOP, RC, BA, TOP) are required to respond to the following questions A and B: (Transmission Owners are not required to submit a response to the questions below.)

A. **For GOs and GOPs:** Do you own or operate any solar generation plants that are registered in the Bulk Electric System (BES)? (Yes, No, Not Applicable)

B. **For RCs, BAs, and TOPs:** Do you consider the potential for widespread solar resource loss during transmission faults on the power system within your Reliability Coordinator or Balancing Authority Areas in daily plans? (Yes, No, Not Applicable)

The following questions should be answered and submitted in the attached worksheet for those entities that answered yes in question A

above. Use the "Add Additional Document" link in the NERC Alert System response web page to submit the completed worksheet. Use a separate row on the worksheet and answer each question for each Manufacturer and Model number of inverter.

1. Enter the manufacturer name of the inverter (e.g., ABC).
2. Enter the model number of the inverter (e.g., DEF-123 or 45678).
3. Enter the name plate MW rating of inverter (e.g., 25 MW).
4. Enter the total number of inverters you have for each Manufacturer and Model number of inverter (e.g., 3).
5. Is each solar inverter currently susceptible to erroneous frequency calculations as described in the 1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report (Consult with your manufacturer)? (Yes, No, Not Applicable)
6. If you answered "Yes" to (question 5), have you reviewed and implemented manufacturer recommendations to this inverter's control settings to ensure that the inverter will not trip due to an erroneous frequency measurement during transients on the power system? (Yes, No, Not Applicable)
7. Does the solar inverter momentarily cease output during abnormal voltages on the power system? (Yes, No, Not Applicable)
8. If you answered "No" to (question 7):
    a. Are you regulating to a voltage schedule? (Yes, No, Not Applicable)
    b. Are you regulating to a VAR schedule? (Yes, No, Not Applicable)
9. If you answered "Yes" to (question 7):
    a. At what lower voltage level (in per units) does momentary cessation occur (e.g., 0.9)?
    b. If you answered "Yes" to (question 7), at what upper voltage level (in per units) does momentary cessation occur (e.g., 1.1)?
    c. If you answered "Yes" to (question 7), what is the maximum delay (in seconds) for this inverter to resume previous output levels (after voltage has returned to normal and including any delay and ramp rate) (e.g., 3.5 seconds)?
        i. If your answer is greater than five (5) seconds in (9c), can this inverter's settings be changed to make the

maximum delay no greater than five (5) seconds? (Yes, No, Not Applicable)

1. If you answered "Yes", to (9ci), have you made the recommended changes to this inverter's settings to ensure that the maximum delay to return to current injection is no greater than five (5) seconds following system conditions requiring momentary cessation(including any delay and ramp rate)? (Yes, No, Not Applicable)

10. Have you provided your response to the questions in this alert to your Reliability Coordinator, Balancing Authority, and Transmission Operator? (Yes, No, Planned)

Background:

NERC reviewed several events involving faults on the transmission system that resulted in the loss of a significant amount of solar photovoltaic generation. The most significant event resulted in the loss of ~1,200 MW of utility-scale solar photovoltaic generation. The facilities ceased output in response to the transient fault on the system.

Based on information provided by the inverter manufacturers, solar development owners and operators, and the registered entities, the largest percentage of the resource loss was attributed to an incorrectly calculated low frequency condition, to which the inverter responded by "tripping" (ceasing to inject current into the grid for a period of approximately five (5) minutes). The inverters used a method that resulted in erroneous instantaneous frequency calculation.

The second largest significant contributor was determined to be inverter "Momentary Cessation" due to system voltage reaching the low-voltage ride through setting of the inverters. In momentary cessation, the inverter control ceases to inject current into the grid while the voltage is outside the continuous operating voltage range of the inverter. When the system voltage returns within the continuous operating range, the inverter will resume current injection after a short delay. The present recommendations are to return to injection in less than five (5) seconds.

Actions may be needed by Reliability Coordinators and Balancing Authorities to preserve and protect bulk power system reliability such as adjustments in operating reserves. NERC encourages entities to develop and implement a systematic approach to mitigate the undesired actions of the inverters.

Recommendations to mitigate these conditions are the subject of this alert. For more information, see the 1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report.

Although this alert pertains directly to BES-connected inverter resources, the same potential susceptibility to frequency and voltage perturbations during transmission faults exist for all utility grade, and perhaps some larger commercial grade solar installations, regardless of the interconnection voltage. Owners and operators of those facilities are encouraged to consult their inverter manufacturers and review the settings utilized in their inverters to determine if the inverters are susceptible.

Contact:

Bulk Power System Awareness Group
North American Electric Reliability Corporation
3353 Peachtree Road NE
Suite 600 – North Tower
Atlanta, Ga. 30326
404-446-9797| nerc.alert@nerc.net

Alert ID: R-2017-06-20-01

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Industry Advisory

Modular Malware Targeting Electric Industry Assets in Ukraine

Initial Distribution: June 13, 2017

The E-ISAC is issuing a Level 1 NERC Alert to inform NERC registered entities of capabilities found in malware that targeted electric industry assets in Ukraine.

[Why am I receiving this? >>]
[About NERC Alerts >>]

Status:	No Reporting is Required – For Information Only
	PUBLIC: No Restrictions [More on handling >>]
Instructions:	NERC advisories are designed to improve reliability by sharing critical reliability information and are made available pursuant to Rule 810 of NERC's Rules of Procedure for use as your organization deems appropriate. **No response is necessary.** A NERC advisory is not the same as a Reliability Standard, and your organization will not be subject to penalties for a failure to implement any recommendations or practices provided in this advisory. Additionally, issuance of this advisory does not lower or otherwise alter the requirements of any approved Reliability Standard, or excuse the prior failure to follow the practices discussed in the advisory if such failure constitutes a violation of a Reliability Standard.
Distribution:	**Initial Distribution:** Balancing Authority, Distribution Provider, Distribution Provider – UFLS, Frequency Response Sharing Group, Generator Owner, Generator Operator, Planning Authority, Reliability Coordinator, Resource Planner, Regulation Reserve Sharing Group, Reserve Sharing Group, Transmission Owner, Transmission Operator, Transmission Planner, Transmission Service Provider [Who else will get this alert? >>] [What are my responsibilities? >>]
Primary Interest Groups:	Cyber Security – Control Systems, Cyber Security – Corporate IT, Generation Engineering, Generation Operations, System Operations – Transmission Engineering, System Operators, System Operators – System Protection, Transmission Planning

Advisory:

Cybersecurity firms Dragos Inc.[1] and ESET[2] reported on malware that specifically targets electric industry assets and has been associated with the cyber-attack that caused an electric outage in Kiev, Ukraine in December 2016. The following is a collaborative effort between the E-ISAC and Dragos Inc. to provide recommended actions in light of the information in their reports.

The malware is a framework comprised of modules that can be added or removed depending on the desired capabilities and the specific devices and equipment found in a victim's environment.

The malware can cause loss of visibility, loss of control, manipulation of control, interruption of communications, and deletion of local and networked critical configuration files.

By leveraging preloaded configuration file(s) with the utility's asset deployment information, the malware can identify open platform communication (OPC) server items and devices that control circuit breakers. These configuration files may also allow the malware to run independently. The malware can also establish communications to cross the Information Technology/Operational Technology (IT/OT) boundary. This was done through customization of the malware to use internal proxy hosts, showing significant understanding of the target environment.

The malware can cause a loss of visibility and control by setting all OPC items to an "out of limits" value, or by killing the Communication Service process, establishing communication with slave devices and behaving as the master process. As the master process, it can set specific values, enumerate Information Object Addresses (IOAs) or set Remote Terminal Unit (RTU) IOAs to open or toggle between open and close. The malware can perform these actions over Transmission Control Protocol (TCP)/Internet Protocol (IP) and serial communications.

After the malware performs its desired effect, it deletes key operating system files and settings of the compromised host and wipes Industrial Control System (ICS) configuration files on local and mapped networked drives.

The malware can reportedly perform a denial of service attack on a specific series of digital protective relays by leveraging a patched vulnerability that will cause an unpatched relay to become unresponsive. Requiring a manual reset of the relay.

[1] https://dragos.com/blog/crashoverride/CrashOverride-01.pdf
[2] https://www.eset.com/us/about/newsroom/press-releases/eset-discovers-dangerous-malware-designed-to-disrupt-industrial-control-systems/

Importantly, the malware causes the aforementioned effects by leveraging the common functionalities and the inherent system-to-system trust typically found in grid operations. It does not leverage vulnerabilities or zero-day exploits for its core desired effects. The malware was coded with advanced knowledge of grid operations and, when used in the cyber-attack in Kiev, was delivered to specifically impact the target location's human machine interfaces (HMIs), remote terminal units (RTU), and circuit breakers.

The malware requires detailed information of the victim's environment to cause desired effects. This information may have been obtained prior to the attack on the Ukrainian utility and loaded into the configuration file(s). Alternatively, the malware may be used to obtain the information.

The malware's framework design allows for the swapping in and out of modules that can tailor its capabilities for different grid ICS environments. While the Ukrainian victim's deployment in that scenario used communication protocols not typically found in the United States (IEC 60870-5-101, and IEC 60870-5-104), the modules that leveraged those communication protocols could be replaced with modules to impact protocols that are relevant and in high use throughout North America. Therefore, the malware's attack capabilities may not be limited to a technology or specific vendor.

Direct external communication was not necessary for the malware to function. The Ukraine utility's ICS environment required the malware to communicate externally using a local proxy. The proxy communicated externally by beaconing on 3128/tcp. Once a connection was established, it initiates a backdoor by sending POST requests that include the compromised Windows system's global unique identifier (GUID) in the body of the packets. The GUID is used to authenticate the compromised system. Communication to an external command and control (C2) server is accomplished through the proxy and across TOR exit nodes.

The malware sample examined by ESET was reported to have a denial of service module that leveraged the patched vulnerability CVE-2015-5374. This vulnerability targets SIPROTECT digital protective relays. Although this vulnerability is vendor specific, the malware does not need this module's functionality to perform its core objective. Additionally, there is no evidence that SIPROTECT relays were targeted in the Ukraine attack.

Due to the malware's capability to act autonomously through time bombs, passive defenses such as air gapping will not prevent the malware from being activated once in the network. In the attack on the Ukrainian utility, the time bomb was used to execute ICS file wiping hours after the breakers were set to open or toggle between open and close.

Currently, the E-ISAC is not aware of how the malware was introduced into the Ukrainian victim's network.

Recommended Actions:

The E-ISAC encourages members to limit privileged access and remove unnecessary privileged accounts from the ICS environment. Authentication should include two factor authentication. Also, members should develop an understanding of the communication protocols used in their ICS environment and create a baseline of how these protocols are typically used. This base knowledge should be used to monitor network traffic for deviations in Master/Slave communication and abnormal telemetry and IOA settings.

The modular nature of the malware makes it is unlikely that file hashes and other signature-based detection methods will effectively detect the malware on a host. Application whitelisting on HMIs may prevent some malware from executing. Behavior-base detection methods, such as YARA rules, may provide a higher confidence of detection.

Proper patch management processes will also help mitigate the effectiveness of some add-on functionalities of the malware, such as the denial-of-service module. Software updates should be validated with digital hashes from the vendor. Additionally, a redundant backup and recovery strategy can mitigate the effects of the malware's data wiping functionality.

Background:

The malware at the center of this notification is a development and improvement on previous cyber-attack trade craft used to attack Ukraine's electric infrastructure. Prior to the December 18, 2016 cyber-attack that leveraged this malware, Ukraine's electric infrastructure was the victim of another cyber-attack that affected approximately 225,000 customers for several hours.

On December 23, 2015, three of Ukraine's 23 *Oblenergos* were attacked. The coordinated attacks focused on breaker controls at three electricity distribution sites. The breakers were opened through remote access to the operations environment.

The 2016 attack on Ukraine's grid automated a lot of the actions necessary to cause the desired effect. The actors behind these cyber –attacks appear to continue developing and improving their ability to impact Ukraine's power grid.

Generally, the E-ISAC continues to request:

- Member feedback on the quality of indicator provided by the E-ISAC.
- Additional details, including activity logs or forensic artifacts, such as binaries or network captures to derive stronger context or indicators that can be shared with members and partners.
- High-confidence indicators or signatures for both untargeted and targeted threats to the electricity sector.

With this information, the E-ISAC can provide updates allowing members to be more effective in detecting and scoping of this activity and other threats. We encourage members that have information regarding successful detections of threats, or updates involving suspected activity later determined benign, to share them on the E-ISAC portal (https://www.eisac.com).

Contact:

Electricity ISAC
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Atlanta, GA 30326
alerts@eisac.com

Alert ID: A-2017-06-13-01

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ERO Enterprise Combined 2018 Budgets and Assessments

Scott Jones, Vice President of Finance
Finance and Audit Committee Meeting
August 9, 2017

RELIABILITY | ACCOUNTABILITY

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2017 vs 2018 Budgeted Expenses ($000's)

Entity	2017	% of Total ERO Budget	2018	% of Total ERO Budget	% Change
NERC	$ 69,602	36.3%	$ 73,135	37.0%	**5.1%**
FRCC	7,178	3.7%	7,514	3.8%	**4.7%**
MRO	11,227	5.9%	11,727	5.9%	**4.5%**
NPCC	15,147	7.9%	15,107	7.6%	**-0.3%**
RF	19,909	10.4%	21,394	10.8%	**7.5%**
SERC	17,482	9.1%	17,183	8.7%	**-1.7%**
SPP RE	10,866	5.7%	10,793	5.5%	**-0.7%**
TRE	12,167	6.4%	12,657	6.4%	**4.0%**
WECC	26,797	14.0%	27,097	13.7%	**1.1%**
WIRAB	1,229	0.6%	1,068	0.5%	**-13.1%**
	$ 191,604	**100.0%**	**$ 197,675**	**100.0%**	**3.2%**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2017 vs 2018 Average Assessments
($000's)

Entity	2017	2018	Change 2018 v 2017	% Change
NERC	$ 59,856	$ 62,937	$ 3,081	**5.1%**
FRCC	6,164	6,661	497	**8.1%**
MRO	10,494	10,730	236	**2.2%**
NPCC	14,255	14,342	87	**0.6%**
RF	19,561	20,148	587	**3.0%**
SERC	15,706	17,205	1,499	**9.5%**
SPP	9,093	9,727	635	**7.0%**
TRE	9,595	11,272	1,677	**17.5%**
WECC	25,282	25,282	0	**0.0%**
WIRAB	901	711	-190	**-21.1%**
TOTAL ERO ENTERPRISE	**$ 170,908**	**$ 179,014**	**$ 8,106**	**4.7%**

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Change in Total ERO Enterprise Assessments (by Region)

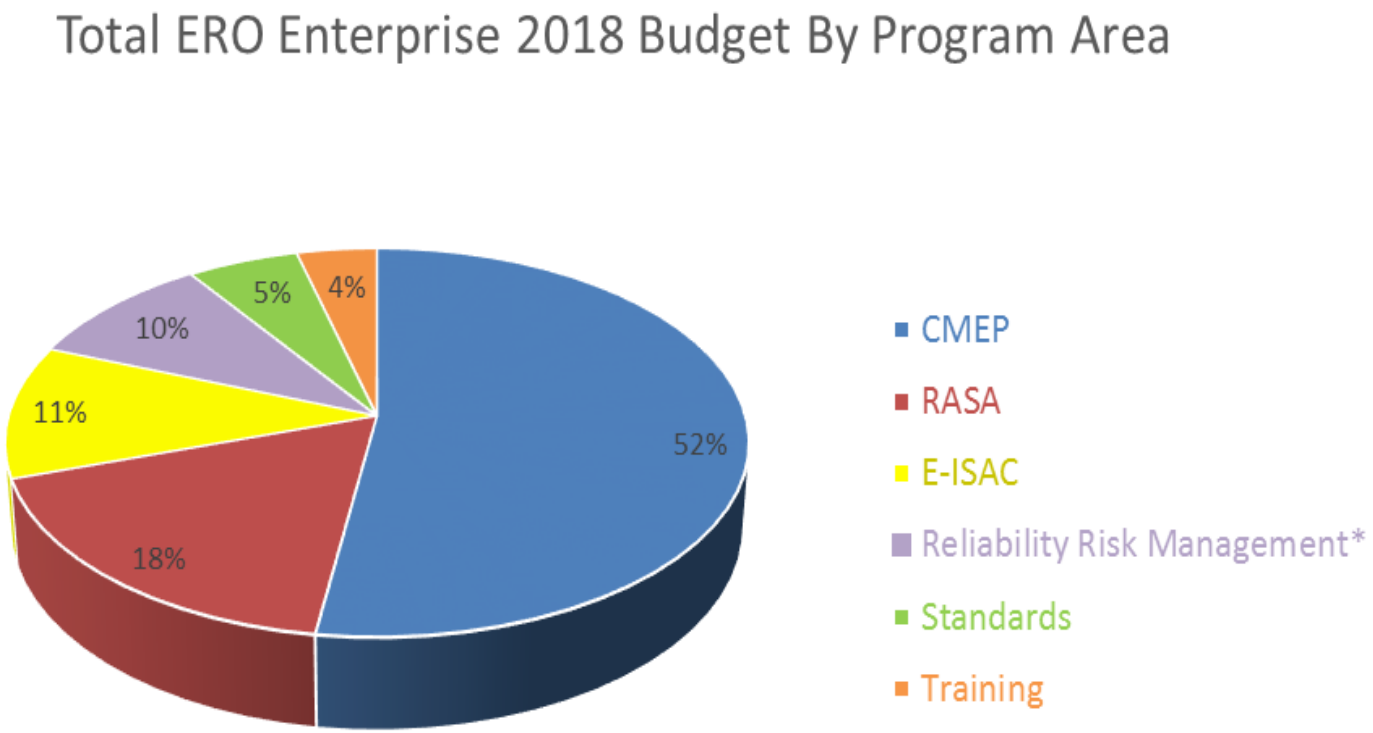
REGION	% Change 2016 v 2015	% Change 2017 v 2016	% Change 2018 v 2017
FRCC	7.6%	-2.0%	6.9%
MRO	11.8%	-2.1%	3.6%
NPCC	1.3%	1.0%	2.6%
RF	3.3%	1.8%	3.9%
SERC	2.1%	10.0%	7.3%
SPP RE	-6.5%	4.5%	6.7%
TRE	-4.6%	2.5%	13.8%
WECC	1.1%	1.4%	0.6%
Total $ Change	**$ 2,977,758**	**$ 4,399,595**	**$ 8,106,719**
Total % Change	**1.8%**	**2.6%**	**4.7%**

Note: NERC assessments are allocated to each Regional Entity using NEL data. For purposes of this table, NERC assessments were allocated using the 2016 data.

Factors Impacting Change in Assessments By Entity

- NERC and Regional Entity resource requirements and budgets
- Year-End reserve levels
  - Surplus reserves
  - Reserves from prior years that can be applied
- Penalty funds and stabilization reserves (U.S. only)
  - Loss of one time offsets applied in prior year
  - New penalty funds available
- Year to year NEL (Net Energy for Load) variations
- Application and true-up of certain Canadian credits

Combined Budget by Program Area



*For NERC Includes Performance Analysis, Event Analysis and Situation Awareness
For Regions includes Situation Awareness

ERO Enterprise Resource Allocation

Questions and Answers

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Proposed Additional Resolutions for Agenda Item 9.a: Cyber Security – Supply Chain Risk Management – CIP-005-6, CIP-010-3, and CIP-013-1

Board of Trustees Meeting

August 10, 2017

WHEREAS, the Board has adopted proposed Reliability Standards CIP-005-6, CIP-010-3, and CIP-013-1, addressing cyber security supply chain risk management issues (the "Supply Chain Standards"), and approved the associated implementation plans;

WHEREAS, the Board has solicited and considered policy input from NERC stakeholders in connection with the adoption of the Supply Chain Standards, including soliciting recommendations (i) to support effective implementation of the Supply Chain Standards, (ii) to evaluate the effectiveness of the Supply Chain Standards, (iii) on risks and related issues for continued study by NERC on a collaborative basis, and (iv) for other actions NERC should take, potentially in collaboration with trade forums and small system representatives, to address potential supply chain risks;

WHEREAS, the Board, in response to the foregoing policy input and input from NERC management, desires to request certain actions by NERC management and stakeholders to assist in the implementation and evaluation of the Supply Chain Standards and other action to address potential supply chain risks for assets not currently subject to the Supply Chain Standards;

NOW, THEREFORE, BE IT RESOLVED, the Board hereby requests that NERC management promptly commence appropriate preparations for implementation of the Supply Chain Standards, utilizing methods similar to those utilized for the implementation of the CIP v 5 reliability standards as deemed appropriate by NERC management, and regularly report to the Board on such activities.

FURTHER RESOLVED, that the Board hereby requests that (i) NERC management, in collaboration with the appropriate NERC technical committees, industry representatives and appropriate experts, including representatives of industry vendors, further study the nature and complexity of cyber security supply chain risks, including risks associated with low impact assets not currently subject to the Supply Chain Standards, and develop recommendations for follow-up actions that will best address any issues identified, and (ii) NERC management provide an interim report to the Board related to the foregoing by no later than approximately 12 months after the adoption of these resolutions and a follow-up final report to the Board no later than approximately 18 months after the adoption of these resolutions.

FURTHER RESOLVED, the Board hereby requests that the NERC management, utilizing information it is authorized to use and other information collected through interactions with industry and governmental authorities, communicate supply chain risk developments and risks to industry and in connection with the efforts contemplated by the foregoing resolutions.

FURTHER RESOLVED, that the Board hereby requests that each of the North American Transmission Forum and the North American Generation Forum (the "Forums") develop white papers to address best and leading practices in supply chain management, including procurement, specifications, vendor requirements and existing equipment management, that are shared across the membership of each

Forum, and to the extent permissible under any applicable confidentiality requirements, distribute such white papers to industry.

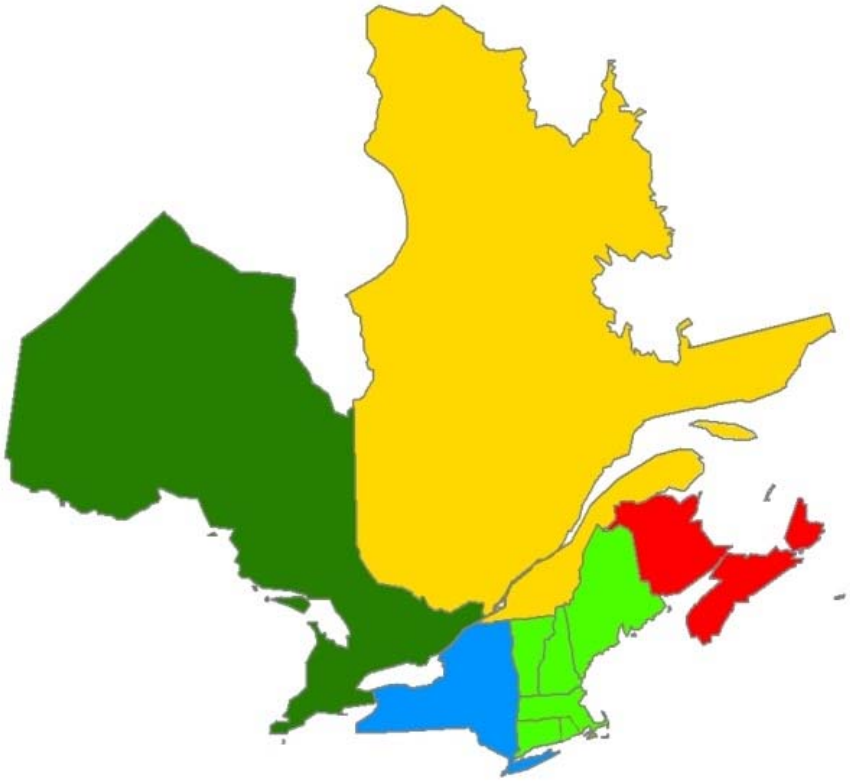
FURTHER RESOLVED, that the Board hereby requests that each of the National Rural Electric Cooperative Association and the American Public Power Association (the "Associations") develop white papers addressing issues contemplated by the immediately preceding resolution, focusing on smaller entities that are not members of the Forums, for the membership of the Associations, and to the extent permissible under any applicable confidentiality requirements, distribute such white papers to industry.

FURTHER RESOLVED, that the Board hereby requests that NERC management, collaborating with the appropriate NERC technical committees and other experts as deemed appropriate by management, develop a plan to evaluate the effectiveness of the Supply Chain Standards, including seeking input from registered entities subject to the Supply Chain Standards, and report back to the Board as appropriate.

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

Northeast Power Coordinating Council, Inc. (NPCC)

2018 Business Plan and Budget



Draft 1
Submitted to NERC May 5, 2017

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Introduction

Total NPCC Resources (in whole dollars)	2018 Budget	U.S.	Canada	Mexico
Regional Entity Division FTEs	36.86			
Criteria Services Division FTEs	2.14			
Total FTEs	**39.0**			
Regional Entity Division Expenses	$15,260,967			
Criteria Services Division Expenses	$1,082,983			
Total Expenses	**$16,343,950**			
Regional Entity Division Inc(Dec) in Fixed Assets	**($154,000)**			
Criteria Services Division Inc(Dec) in Fixed Assets	**($16,000)**			
Total Inc(Dec) in Fixed Assets	**($170,000)**			
Regional Entity Division Working Capital Requirement**	**($626,180)**			
Criteria Services Division Working Capital Requirement***	**($47,843)**			
Total Working Capital Requirement	**($674,023)**			
Total Regional Entity Division Funding Requirement	$14,480,787			
Total Criteria Services Division Funding Requirement	$1,019,141			
Total Funding Requirement	**$15,499,927**			
Regional Entity Division Assessments	**$14,341,787**	$XXX,XXX	$XXX,XXX	
Regional Entity Division Assessments Percentage	**100.0%**	XX.X%	XX.X%	
Criteria Services Division Membership Fees	**$1,019,141**	$XXX,XXX	$XXX,XXX	
Total NPCC Assessments & Membership Fees	**$15,360,927**	$XXX,XXX	$XXX,XXX	
NEL	XX	XX	XX	
NEL %	100%	XX.XX%	XX.XX%	

** Refer to Table B-1 on page 66 in Section B.
*** Refer to the Reserve Analysis on page 83 in Section C.

2018 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 no change to its total budget and assessments. On a division level, NPCC proposes a Regional Entity total budget decrease of 0.3% and a Criteria Services division total budget increase of 3.8%. The proposed 2018 funding requirements will be satisfied by a Regional Entity division assessment of $14,341,787 and Criteria Services division fees of $1,019,141, for a total of $15,360,927. The total NPCC assessments and fees of $15,360,927 represents no change from 2017. 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 flat 2018 targeted staffing level of 39 power industry professionals and support personnel. Details of the 2018 business plans and budget for each program area are included in Section A for the Regional Entity division. The 2018 Regional Entity division schedules are shown in Section B. Section C details the 2018 criteria services division business plan and budget.

Membership and Governance

NPCC monitors approximately 205 registered entities and some 427 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.

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 New Brunswick Power Corporation ("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.

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.

2018 Key Assumptions and 2018 Goals and Key Deliverables

NERC and the eight Regional Entities collaborated in the development of a common operating model with complementary roles and responsibilities, an ERO Enterprise Strategic Plan, and a set of business planning assumptions, goals, metrics and key deliverables for the 2017 through 2019 period. The results from that collaboration, which incorporated risks identified by the Reliability Issues Steering Committee, are included as a set of Shared Business Plan and Budget Assumptions that will be contained in Exhibit A to the NERC 2018 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.

2018 Overview of Regional Entity Division Cost Impacts

The proposed Regional Entity division assessment of $14,341,787 to support the budget is an increase of 0.6% compared to the 2017 assessment of $14,255,061.

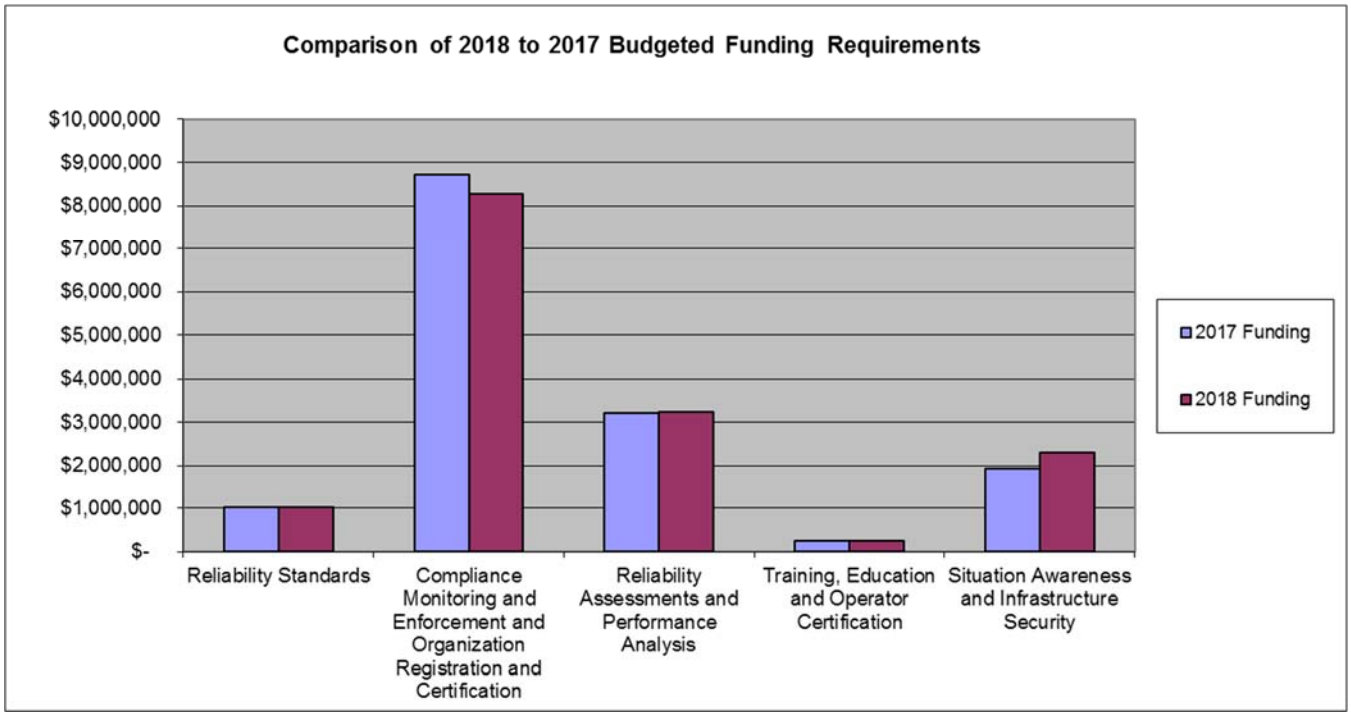
2017 Projections

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. 2017 Projections reflect expectations based on the first quarter variance report. It is anticipated that projections could change throughout 2017 and would be reflected in each subsequent quarter's variance report.

Summary by Program

Program	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Reliability Standards	$ 1,022,328	$ 1,022,328	$ 1,010,246	$ (12,083)	-1.2%
Compliance Monitoring and Enforcement and Organization Registration and Certification	$ 8,726,049	$ 8,726,049	$ 8,293,748	$ (432,301)	-5.0%
Reliability Assessments and Performance Analysis	$ 3,206,966	$ 3,206,966	$ 3,240,721	$ 33,755	1.1%
Training, Education and Operator Certification	$ 248,658	$ 248,658	$ 249,051	$ 393	0.2%
Situation Awareness and Infrastructure Security	$ 1,943,053	$ 1,943,053	$ 2,313,202	$ 370,148	19.0%
Total	$ 15,147,054	$ 15,147,054	$ 15,106,967	$ (40,087)	-0.3%

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 2017	Projection 2017	Direct FTEs 2018 Budget	Shared FTEs[1] 2018 Budget	Total FTEs 2018 Budget	Change from 2017 Budget
REGIONAL ENTITY DIVISION						
Operational Programs						
Reliability Standards	1.93	1.93	1.00	0.93	1.93	0.00
Compliance Monitoring and Enforcement and Organization Registration and Certification	17.00	16.00	16.00	0.00	16.00	-1.00
Training, Education, and Operator Certification	0.10	0.10	0.10	0.00	0.10	0.00
Reliability Assessment and Performance Analysis	5.83	5.83	4.90	0.93	5.83	0.00
Situation Awareness and Infrastructure Security	4.00	5.00	5.00	0.00	5.00	1.00
Total FTEs Operational Programs	**28.86**	**28.86**	**27.00**	**1.86**	**28.86**	**0.00**
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	1.00	0.00	1.00	0.00
Total FTEs Administrative Programs	**8.00**	**8.00**	**8.00**	**0.00**	**8.00**	**0.00**
Total FTEs	**36.86**	**36.86**	**35.00**	**1.86**	**36.86**	**0.00**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

2017Budget and Projection and 2018 Budget Comparisons

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget

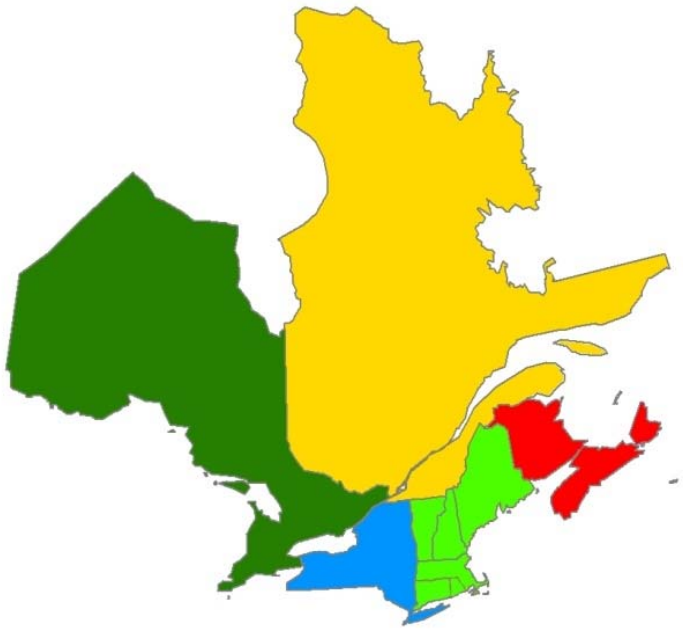
REGIONAL ENTITY DIVISION

	2017 Budget	2017 Projection	Variance[2] 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 14,255,061	$ 14,255,061	$ -	$ 14,341,787	$ 86,726
Penalty Sanctions[1]	-	-	-	75,000	75,000
Total ERO Funding	**$ 14,255,061**	**$ 14,255,061**	**$ -**	**$ 14,416,787**	**$ 161,726**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	64,000	64,000	-	64,000	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 14,319,061**	**$ 14,319,061**	**$ -**	**$ 14,480,787**	**$ 161,726**
Expenses					
Personnel Expenses					
Salaries	$ 6,758,926	$ 6,758,926	$ -	$ 7,107,599	$ 348,673
Payroll Taxes	404,319	404,319	-	411,440	7,121
Benefits	1,415,603	1,415,603	-	1,476,378	60,774
Retirement Costs	847,223	847,223	-	825,353	(21,869)
Total Personnel Expenses	**$ 9,426,071**	**$ 9,426,071**	**$ -**	**$ 9,820,770**	**$ 394,699**
Meeting Expenses					
Meetings	$ 377,100	$ 377,100	$ -	$ 353,050	$ (24,050)
Travel	855,232	855,232	-	834,500	(20,732)
Conference Calls	37,000	37,000	-	37,000	-
Total Meeting Expenses	**$ 1,269,332**	**$ 1,269,332**	**$ -**	**$ 1,224,550**	**$ (44,782)**
Operating Expenses					
Consultants & Contracts	$ 2,009,000	$ 2,009,000	$ -	$ 1,877,640	$ (131,360)
Office Rent	809,700	809,700	-	810,700	1,000
Office Costs	679,100	679,100	-	664,760	(14,340)
Professional Services	1,041,000	1,041,000	-	960,000	(81,000)
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	50,000	50,000	-	50,000	-
Depreciation	250,000	250,000	-	269,000	19,000
Total Operating Expenses	**$ 4,838,800**	**$ 4,838,800**	**$ -**	**$ 4,632,100**	**$ (206,700)**
Total Direct Expenses	**$ 15,534,203**	**$ 15,534,203**	**$ -**	**$ 15,677,420**	**$ 143,217**
Indirect Expenses	**$ (413,149)**	**$ (413,149)**	**$ -**	**$ (416,453)**	**$ (3,304)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 15,121,054**	**$ 15,121,054**	**$ -**	**$ 15,260,967**	**$ 139,913**
Change in Assets	**$ (801,994)**	**$ (801,994)**	**$ -**	**$ (780,180)**	**$ 21,813**
Fixed Assets					
Depreciation	$ (250,000)	$ (250,000)	$ -	$ (269,000)	$ (19,000)
Computer & Software CapEx	276,000	276,000	-	115,000	(161,000)
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	0	0	-	0	-
Inc(Dec) in Fixed Assets (C)	**26,000**	**26,000**	**-**	**(154,000)**	**(180,000)**
TOTAL BUDGET (=B+C)	**$ 15,147,054**	**$ 15,147,054**	**$ -**	**$ 15,106,967**	**$ (40,087)**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (827,994)**	**$ (827,994)**	**$ -**	**$ (626,180)**	**$ 201,813**

(1) $75,000 of penalty sanctions collected to date and prior to June 30, 2017.

(2) 2017 Projections reflect expectations based on the 1st quarter statement of activities. It is anticipated that projections could change throughout 2017 and would be reflected in each subsequent quarter's statement of activities.

Section A – Regional Entity Division
2018 Business Plan and Budget



Section A — 2018 Regional Entity Division Business Plan and Budget

Reliability Standards Program

Reliability Standards Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	1.93	1.93	0.00
Direct Expenses	$658,082	$647,633	($10,448)
Indirect Expenses	$372,606	$375,586	$2,980
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($8,359)	($12,974)	($4,614)
Total Funding Requirement	$1,022,328	$1,010,246	($12,083)

Program Scope and Functional Description

The NPCC Reliability Standards Program Area operates in accordance with NPCC's filed and approved Delegation Agreement and NERC Rules of Procedure Section 300. The program supports the ERO standards program area roles and responsibilities, the 2018 ERO Enterprise Strategic Plan and 2018 Shared Business Plan and Budget Assumptions. NPCC's Reliability Standards Program Area provides an efficient and effective mechanism for stakeholders and the ERO to develop 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 which establishes "results-based" requirements for addressing reliability risks with due consideration given to cost effectiveness. NPCC supports the ERO efforts to develop reliability standards in a timely and efficient manner and which are responsive to FERC Directives and industry risk. ERO and Regional Reliability Standards must ensure the bulk electric system is planned, operated, and maintained in a manner that minimizes risks of cascading failures, 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, ERO Standards Variances for the northeast as required. In addition, the NPCC Reliability Standards Program Area provides oversight to ensure that NPCC's Regional Reliability Criteria contained in the form of Directories, are developed and maintained as necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Reliability Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy and conform to requirements in Section 313 of the NERC Rules of Procedure.

The NPCC Reliability Standards Program Area supports and participates in the development, revision, and maintenance of NERC ERO Reliability Standards, initiates new continent-wide reliability standards through the NERC Standards Authorization Request (SAR) process when necessary, and provides a forum for the comprehensive review and improvement of existing and developing reliability standards. NPCC also provides coordination and represents the other seven NERC Regional Entity for the NERC Enhanced Periodic Review process and participates on the Enhanced Periodic Review Standing Team EPRST. The EPRST reviews existing NERC

standards and grades them for quality and content in an effort to prioritize and improve the reliability benefit of the ERO Reliability Standards.

The NPCC Reliability Standards Program Area also facilitates and assists stakeholders with initiating SARs and Requests for Interpretation of ERO standards for those entities within the NPCC footprint. In 2017 NPCC instituted a feedback mechanism from the Compliance, Event Analysis, RAPA and Criteria Services program area which provides a process to identify and improve standards. The standards program area will receive input from these other program areas and take appropriate action to support the revision, retirement, or development of new standards to improve the ERO set of reliability standards and improve reliability of the Bulk Electric System. The NPCC Reliability Standards Program Area conducts its oversight and participation in the ERO standards development process by utilizing the NPCC Regional Standards Committee (RSC) to ensure transparency and facilitate stakeholder input.

The NPCC Reliability Standards Program Area supports the reliability of the bulk electric system by:

- Facilitating active participation of NPCC Regional industry stakeholders in all NERC Reliability Standards activities to promote the development of results-based, cost effective, clear and concise quality standards in a timely and efficient manner.
- Providing selective support for standard development activities as outlined in the NERC 2018-2020 Reliability Standards Development Plan (RSDP)
- Participating in and representing the other Regional Entities on the EPRST which evaluates need to revise existing standards, prioritizes the standards development projects for the future year's RSDP, and allows the Regions to identify opportunities to replace Regional Standards with Variances in the continent wide standards.
- Support ERO outreach during standard development by providing a forum for all NPCC representatives on the NERC drafting teams to raise issues, socialize concepts with stakeholders, and receive feedback on the standards during the development process to enhance efficiency and timeliness of standards development
- Assisting NERC with the evaluation of the standards from a "cost effectiveness" perspective by supporting ongoing pilots and participating in the development of a formal process.
- Promoting awareness by holding Regional workshops to provide outreach and conducting Regional Standards Committee meetings to inform and educate stakeholders on standards being developed, modified or maintained.
- Utilizing input received from the NPCC Regional feedback mechanisms, identify and initiate improvements to NERC standards.
- Actively participate and review the work of the NERC Reliability Issues Steering Committee (RISC) which identifies emerging risks to the BES.
- Coordinating and sharing activities and useful information such as presentations, implementation documents and training materials as necessary with Standards Program Areas from other Regions to enhance efficiencies and promote consistency amongst the Regions.
- Developing and maintaining Regional Standards as necessary to address Regional reliability related issues or risks and ensure those standards set more stringent reliability requirements than the associated NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard all in accordance with Section 312 of the NERC Rules of Procedure.

- Pursuing retirement of Regional Standards through promoting the reliability objectives of those Regional Standards into the NERC Continent-wide standards and developing Variances to the NERC standards where possible to capture the reliability objectives of the Regional Standards.
- Maintaining and abiding by the NPCC Regional Standard Processes Manual assuring compliance with all FERC filed documents with respect to standards development.

2018 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 conducting periodic reviews on existing Reliability Standards to improve their content and quality, respond to identified risks to reliability (including those that may be identified through the implementation of risk-based Compliance Monitoring and Enforcement), and address 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 low, driven by requests that the Regional Entity may receive or reliability issues that are identified.
- In coordination with NERC's Standard Drafting Teams and consistent with current approaches, NPCC will support outreach during standard development and participate in the standard development activities as may be required to address reliability and stakeholder issues that may arise.
- Following FERC approval, NPCC will assist with the transition of Reliability Standards to compliance monitoring and enforcement by supporting industry and auditor training or providing information regarding the intent of the Reliability Standard.
- 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.

2018 Goals and Key Deliverables

The Reliability Standards program goals and objectives for 2018 are grouped into six categories:

1) Participate in the ERO Results-Based Standards Development

- Participate in the annual development and revision of the NERC 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, participate in standards EPR activities, ensure any outstanding FERC Directives are addressed, and coordinate and prioritize 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 development of ERO Reliability Standards within NERC's three-year standards work 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 being developed or revised and coordinate comments for Northeastern North America driving consensus to the extent possible through the Enhance Periodic Review Standing team and processes. Ensure all developing standards receive a review for adequate level of reliability, cost effectiveness and are technologically neutral and focused on achieving a reliability objective
- Assist NERC's review of all industry "Requests for Interpretations" of standards
- NPCC staff, along with NPCC solicited regional drafting team volunteers, will participate in the drafting of ERO standards affecting or potentially affecting reliability in the Eastern Interconnection and provide support for review and development of comments and propose improvements
- NPCC and its members will review and coordinate members' 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
- Coordinate and evaluate proposed standards utilizing NPCC's technical task forces, working groups and committees
- 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
- Provide a forum for NPCC review of proposed and posted standards related documents from the NERC Critical Infrastructure Protection Committee (CIPC) and NPCC Task

Force on Infrastructure Security and Technology (TFIST) such as but not limited to whitepapers and technical guidelines

- Participate in the NERC RISC 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), GMD, etc.
- Identify and initiate Regional Variances to the NERC Reliability Standards as soon as possible, allowing incorporation into the continent wide standard
- .
- Provide support and assistance to the ERO, as needed, for conducting Quality Review activities on NERC continent-wide standards
- Continue to develop new and innovative processes to better utilize the limited internal and external resources in the Region to enable sufficient technical review of posted standards and related materials
- Support the ERO and the relationships with FERC and applicable provincial governmental authorities for standards development activities as necessary to accomplish the ERO's strategic goals and objectives
- Participate in the improvement of NERC standards though lessons learned and various ERO and Regional feedback mechanisms using input from Compliance, RAPA, Event Analysis, and stakeholders
- Provide support to the Compliance Guidance Policy activities as required.
- Provide support to ERO staff for FERC related matters in the area of standards development such as pre-filing meetings, preparation of filings, and technical conference participation

2) Regional Standards Development

- NPCC does not plan on developing further Regional Standards but reserves the right to do so if a reliability issue exists that is not appropriate for continent-wide development and also will perform clarifications as needed to existing approved Regional Standards in accordance with all NERC Rules of Procedures and NERC and Regional Standards processes
- Conduct reviews for opportunities to include Regional Standards as Variances into the associated NERC continent wide standards as they individually undergo Enhanced Periodic Reviews
- Conduct periodic 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.

3) Standards Improvement

- Achieve NPCC Northeastern North American reliability goals and objectives by initiating, participating in, and efficiently completing standards related activities and promote these reliability objectives in continent-wide standard development projects
- Leverage internet and web based tools functionality to ensure inter-Regional consistency and quality of Regional Reliability Standards
- Support long-term strategy for standards improvement, help develop and initiate implementation of more efficient processes

- Identify any reliability related need for additional Regional Standards opportunities if continent-wide standards are not an appropriate or possible solution
- Ensure the topics addressed by the Reliability Standards parallel changing industry needs
- Participate in reliability metrics activities to identify potential measures for benchmarking of reliability and standards to determine if an adequate level of reliability is being achieved through the Enhanced Periodic Review Standing Team activities
- Identify opportunities and processes for cost-effectiveness CRRA analysis activities to determine the need to revise a standard during the EPR process
- Identify any emerging interconnection-wide reliability issues which may need standards solutions and forward to the NERC Reliability Issues Steering Committee.
- Identify opportunities to increase reliability through the revision of standards and their associated requirements

4) Business Practices Interface

- Coordinate the review of standards through NPCC RSC, staff, and other members participating in activities of the North American Electric Standards Review Board (NAESB)
- 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

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Reliability Standards Program

Funding sources and related expenses for the Reliability Standards section of the 2018 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 2017 Budget & Projection, and 2018 Budget Reliability Standards						
		2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 1,022,328	$ 1,022,328	$ -	$ 1,005,230	$ (17,098)
	Penalty Sanctions	-	-	-	5,016	5,016
Total ERO Funding		**$ 1,022,328**	**$ 1,022,328**	**$ -**	**$ 1,010,246**	**$ (12,083)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 1,022,328**	**$ 1,022,328**	**$ -**	**$ 1,010,246**	**$ (12,083)**
Expenses						
Personnel Expenses						
	Salaries	$ 370,220	$ 370,220	$ -	$ 377,093	$ 6,873
	Payroll Taxes	21,273	21,273	-	21,390	116
	Benefits	97,411	97,411	-	98,851	1,441
	Retirement Costs	43,020	43,020	-	40,299	(2,721)
Total Personnel Expenses		**$ 531,925**	**$ 531,925**	**$ -**	**$ 537,633**	**$ 5,709**
Meeting Expenses						
	Meetings	$ 13,000	$ 13,000	$ -	$ 7,000	$ (6,000)
	Travel	103,157	103,157	-	93,000	(10,157)
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 116,157**	**$ 116,157**	**$ -**	**$ 100,000**	**$ (16,157)**
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	**$ 658,082**	**$ 658,082**	**$ -**	**$ 647,633**	**$ (10,448)**
Indirect Expenses		**$ 372,606**	**$ 372,606**	**$ -**	**$ 375,586**	**$ 2,980**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,030,688**	**$ 1,030,688**	**$ -**	**$ 1,023,220**	**$ (7,468)**
Change in Assets		**$ (8,359)**	**$ (8,359)**	**$ -**	**$ (12,974)**	**$ (4,614)**
Fixed Assets						
	Depreciation	$ -	-	$ -	-	$ -
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	(8,359)	(8,359)	-	(12,974)	(4,614)
Inc(Dec) in Fixed Assets (C)		**(8,359)**	**(8,359)**	**-**	**(12,974)**	**(4,614)**
TOTAL BUDGET (=B+C)		**$ 1,022,328**	**$ 1,022,328**	**$ -**	**$ 1,010,246**	**$ (12,083)**

Compliance Monitoring and Enforcement and Organization Registration and Certification Program

Compliance Monitoring and Enforcement and Organization Registration and Certification Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	17.00	16.00	-1.00
Direct Expenses	$5,366,656	$5,247,634	($119,022)
Indirect Expenses	$3,282,024	$3,113,668	($168,356)
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$77,369	($67,554)	($144,922)
Total Funding Requirement	$8,726,049	$8,293,748	($432,301)

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. and 3) the implementation of compliance monitoring, assessment and enforcement recommendations in accordance with individual executed MOUs or Agreements in the Canadian Provinces of Ontario, Québec, New Brunswick and Nova Scotia.

The NPCC Compliance Committee (CC) is charged with providing objective stakeholder policy input to NPCC's implementation of the CMEP in the U.S. and compliance related activities under the above mentioned MOUs in the NPCC portion of Canada. With regard to NERC Reliability Standards and Regional Reliability Standards, the CC provides an oversight role of the independent NPCC compliance staff's implementation of the CMEP. In this oversight role the CC will review and endorse the processes used by the NPCC compliance staff in the conduct of the CMEP.

The NPCC compliance staff makes the initial and final determination of alleged violations and determines appropriate penalties and sanctions in accordance with the NERC *Sanction Guidelines*. To accomplish this objective, NPCC's compliance staff is further divided into four sub- program areas: Compliance Implementation and Registration; Compliance Entity Risk Assessment, Compliance Monitoring; and Compliance Enforcement.

Compliance Implementation, Registration and Certification

The Compliance Implementation and Registration sub-program is responsible for:

a) Continue to use the risk-based registration model to maintain an accurate registry and correctly identify all entities that are required to meet the NERC and Regional Reliability Standards.
b) Performing the annual review of the recently created enhanced registration database, assuring that all entity data, such as latest entity risk assessment data, BES asset listing, etc.is correct and up to date.
c)
d) Representing NPCC on the NERC –led Review Panel whose role is to make decisions related to resolving - identified registration issues, such as registered entities requests for a materiality assessment, an identification of an applicable subset of NERC Standard requirements, etc;
e) Engaging with those registered entities who are requesting a materiality assessment or an identification of an applicable subset of requirements in advance of these issues being presented to the NERC-led Review Panel;
f) Working within the ERO Enterprise on monitoring the progress of the development and implementation of new Registration and CMEP software reporting systems and tools.
g) Developing and maintaining all NPCC and NERC CMEP Compliance Procedures, Compliance Instructions and all other CMEP related documentation;
h) Developing and maintaining Performance Metrics that are used to measure the quality and effectiveness of CMEP Implementation and its impact on the reliability of the Bulk Electric System;
i) Coordinating the implementation of NPCC Compliance Staff responsibilities as they pertain to the executed MOU with each of the Canadian Provinces in the NPCC Region.
j) Day-to-day implementation of the CMEP;
k) Developing of NPCC's annual CMEP Implementation Plan;
l) Monitoring and assessment of guided self-certification, self-report, exception reporting, periodic data and complaint submittals;
m) Updating and maintaining theCMEP Data Administration Application (CDAA);
n) Implementing required changes and maintenaining the Registration and Compliance portions of the NPCC website.
o)
p) Participating on various NERC and NPCC working groups to influence changes to Compliance processes, and support commonality of registration, monitoring, auditing, and enforcement approaches.

Compliance Monitoring Program

The Compliance Monitoring Program is charged with conducting both on-site and off-site compliance audits, spot checks, and guided self-certifications of NERC Reliability Standards in accordance with the NERC Rules of Procedure and associated NPCC procedures developed under the NPCC Compliance Implementation Program. NPCC's Compliance Monitoring area provides supporting activities by implementation of the risk-based Compliance Monitoring and Enforcement Program (CMEP); and by use of consistent compliance monitoring practices focused on higher reliability risks. NPCC uses risk profiles from the IRAs (inherent risk assessments) as a baseline evaluation of reliability risks of an entity. NPCC also uses IRA summaries to guide its efforts to identifying key focus areas and evolving reliability risks. Internal Control Evaluations (ICE) are performed for registered entities that agree to identify key

focus areas for a CMEP engagement. The result is a list of reliability requirements that merit a continued level of focus.

NPCC also supports the ERO Enterprise learning effort, as well as NERC oversight of program implementation. In collaboration with NERC, NPCC supports outreach programs in new CIP versions and in implementation of CIP-014 with anticipated expansion in the number and type of registered entities that require guidance. Compliance engagements are performed on the basis of risk to the BES and take into account the ERO reliability risk priorities. The Reliability Assessment (RA) group performs an IRA of all registered entities and forwards results to the manager of compliance to develop a schedule. Previous performed IRAs are amended and updated based on identified triggers. The yearly schedule is produced consistent with Risk Assessment of registered entities and the desired frequency of CMEP engagements. The schedule is posted annually on NERC and NPCC public websites.

Flexibility may be used in the CMEP engagement frequency based on the risk assessment and performance based assessment of each entity scheduled for an audit, and changes requiring certification. NPCC compliance monitoring is focused on the most significant risks to the BES. CMEP engagement may be in the form of an audit, spot check or guided self-certification and are led by qualified senior NPCC Staff. Compliance Oversight Plans are developed for registered entities to address the relevant risks. NPCC also conducts outreach, training, and education as necessary to support the implementation of new Reliability Standards.

Findings include the identification of any possible violations. Contents and processing of audit and spot check reports are in accordance with NERC directives for reporting. Specific lessons learned are factored into the program to promote continuous improvement and are presented at workshops. An annual comprehensive guided self-certification program is established based on the NERC and NPCC Risk Elements. Spot checks are based on NPCC's assessment of follow–ups on entities that have previously violated a Reliability Standard, follow-up on entities that have been involved in a significant system event, and other requirements which at the discretion of NPCC could pose a higher risk to reliability if not followed properly.

Resources from the Compliance Audit Program are also used to implement the Certification process for entities intending to register as new TOPs, BAs or RCs, as well as certification reviews of changes made by existing TOPs, BAs and RCs that meet the threshold requiring same. These actions are performed in support of the Compliance Registration Program which encompasses the Certification process. Resources for this activity, which is independent of the audit process, depend on the scope, function, and location of the entity being certified.

Compliance Entity Risk Assessment

The Entity Risk Assessment group conducts activity that informs the risk-based approach for CMEP engagement scoping. They conduct an entity's IRA prior to scoping the compliance engagement to determine which CMEP tool will be used.

Entity risk also includes an assessment of an entity's Internal Controls which is used for further refinement of requirements to be included in the engagement. While separate ICE engagements are voluntary and must be agreed to by the entity, internal controls may also be reviewed as needed during an audit.

Compliance Investigation

A Compliance Investigation (CI) may be initiated at any time by NPCC in response to a system disturbance, complaint, or possible violation of a Reliability Standard identified by any other means. The CI process requires the establishment of an investigation team that coordinates with NERC and FERC as necessary; and also coordinates with the Situation Awareness Program Area.

Compliance Enforcement

In processing identified violations NPCC Compliance Enforcement strives to promote both timeliness and transparency of compliance results utilizing a risk-based compliance enforcement approach, including those efforts associated with meeting the enforcement metrics described below. In addition NPCC promotes the use of self-identification of non-compliance and implementation of discretion, including increased utilization of streamlined tracks such as FFT and discretion as shown below.

Compliance Enforcement responsibilities:

a) Issuing all applicable notices including the Notice of Preliminary Screen; Notice of Compliance Exception; Notice of Possible Violation (NOPV), Notice of Find, Fix and Track (FFT) Treatment; Notice of Alleged Violation (NOAV), and the Notice of Confirmed Violation (NOCV);
b) Conducting comprehensive enforcement investigations based on the facts and circumstances related to all possible violations of Reliability Standards, whether identified in an audit, a self-report, complaint, or other source, and determining whether further action is warranted;
c) Reviewing, approving, submitting to NERC and tracking the progress of all mitigation plans /mitigating activities associated with confirmed violations or noncompliances;
d) Coordinating settlement activities once they have been initiated and submitting settlement agreements to NERC for approval;
d) Identifying and processing applicable moderate violations for the FFT Process;
e) Administer both the compliance exception process and the self-logging process for identified minimal noncompliances;
f) Coordinating the identification of possible NERC Reliability Standards revisions and submit issue for proper implementation. Revisions will be based on experiences observed from compliance monitoring activities, enforcement investigations, and event analysis. Work closely with NPCC Reliability Standards Program Area
g) Following up on verifying that proposed Reliability Standards have been implemented and are effective in improving the standards.
h) Participating in the Hearing Process by representing NPCC before the Hearing Body. Compliance Hearings would be conducted at NPCC under the supervision of a qualified, independent hearing officer contracted by NPCC;
i) Issuing Remedial Action Directives when appropriate; and
j) Implementing the risk-based compliance enforcement model including :
    a. Notifying the registered entity, within 60 days on average, whether a non-compliance will proceed through enforcement, be treated as a compliance exception or additional information is needed ("Triage");
k) Developing and monitoring a set of enforcement metrics that support NERC's Strategic Plan and Oversight Program
l) Processing violations based on the individual executed MOUs or Agreements in the Canadian Provinces of Ontario, Québec, New Brunswick and Nova Scotia.

2018 Key Assumptions and Cost Impacts

2017	Projected 2018
8 On-Site Audits	4 On-Site O&P Audits
12 On-Site CIP Audits	10 On-Site CIP Audits
32 Off-Site Audits	30 Off-Site O&P Audits
11 Off-Site CIP Audits	15 Off-Site CIP Audits
15 Spot Checks	15 Spot Checks
25 Guided self-certifications	25 Guided self-certifications
50 Inherent Risk Assessments	50 Inherent Risk Assessments
10 On-site Internal Control Evaluations	4 On-site O&P Internal Control Evaluations
	5 On-Site CIP Internal Control Evaluations
100 Violations (Estimated)	120 Violations (Estimated)
Settlements Covering 50 Violations	Settlements Covering 50 Violations
2 Hearings (Unbudgeted)	2 Hearings (Unbudgeted)
1 CI (Estimated)	1 CI (Estimated)
2 Entity Certifications	4 Entity Certifications

- Regarding the Compliance Audit Program, Technical Feasibility Exception (TFE) reviews are conducted both on-site at the entity's facility and at the NPCC offices when possible. TFE's continue to be requested as entities replace and install new equipment/devices/components that meet the criteria set forth in Rules of Procedure Appendix 4D. Compliance estimates four on-site reviews will be performed in 2018.
- Decrease in audit costs reflects Risk Assessment activity that is the basis for entity engagement scoping. The Risk Assessment includes an assessment of an entity's Internal Controls which is used for future reduction in engagement scoping and frequency of engagements.
- Potential increases due to the newly identified role related to implementing the QCMEP in Québec and the continuing role of implementing the NB CMEP in New Brunswick.
- The 2018 Business Plan projects no significant increases in Enforcement Processing activities over the 2017 Budget.
- The 2018 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).

2018 Goals and Key Deliverables

- Conduct 2018 CMEP consistent with a risk-based compliance monitoring and enforcement model, assessing IRA; conducting voluntary ICE; and expanding the use of compliance exceptions and the self-logging program for disposition of minimal violations.
    - Continue to process identified violations as effectively as possible, including the timely identification of a violation and its disposition method (e.g. compliance exceptions; FFT; etc.), and the timely issuance of appropriate notification to the registered entity and NERC;
    - Continue to implement settlement process when applicable and send proper notifications to NERC and FERC and continue to enhance the settlement process

by modifying existing practices and adopting new practices to reduce the duration of settlement negotiations without sacrificing the rigor and quality of the negotiated settlements;
    - Develop and analyze appropriate performance metrics that track settlement process duration and utilize results of analysis to further enhance process.
    - Conduct necessary Hearings related to resolution of outstanding disputes regarding violations and/or sanctions. Send results of hearings to NERC and FERC.
- Identify potential issues related to NERC Reliability Standards as a result of compliance monitoring, enforcement and event analysis activities.
- Implement proposed changes to NERC Reliability Standards utilizing existing mechanisms.
- Verify effectiveness of proposed changes to reliability standards.
- Provide detailed response to NERC Annual FFT/Compliance Exception Survey;
- Implement compliance responsibilities identified in the approved Canadian MOUs;
- Annual report to NERC and Régie on NPCC implementation of QCMEP
- Annual report to NERC and New Brunswick Electric Utility Board (NBEUB) on NPCC implementation of NB CMEP.
- Provide NPCC Regional Entity input, through participation in appropriate NERC compliance committees, on policy and implementation issues related to compliance and enforcement including the development of compliance elements for all new or revised NERC Reliability Standards;
- Provide required information to NERC on a timely basis including reporting of alleged violations and confirmed violations
- Track the progress of report status and approve mitigation plans and mitigating activities;
- Conduct 2018 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 Inherent Risk Assessment for all scheduled engagements and Internal Control Assessment for all entities that volunteer for one;
- Assure that NPCC Staff is trained to conduct Entity Risk Assessment and CMEP engagements including CIP Compliance Audit training;
- Assure that NPCC staff is trained to conduct Certification of entities intending to Register as BA, RC or TOP for the first time, or Certification Reviews of changes by existing BAs, RCs or TOPs that meet the criteria requiring a Certification Review;
- Continue to implement compliance reform consistent with a risk-based approach by being an integral participant in committees and workgroups that are involved in the development of polices related to the implementation of a risk-based compliance and enforcement model;
- Continue to expand the utilization of compliance exception and self-logging, as it relates to the processing of minimal noncompliances;
- Continue collaboration with ERO Enterprise on consistent compliance monitoring and enforcement practices specifically those with higher reliability risks.
- NPCC will collaborate with NERC to promote better coordination, planning, delivery and management of training efforts across the enterprise through a unified learning

management system (LMS), without adversely impacting region-specific training requirements;
- Continue to 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;
- Provide outreach to the registered entities, related to the latest status of the development and implementation of the ERO Enterprise Registration and CMEP software reporting systems and tools;
- Work with ERO Enterprise, through NPCC participation on the NERC-led Review Panel, to propose a list of possible ROP enhancements related to the NERC-led Review Panel processes and procedures.
- Conduct 2018Compliance Workshops and interim information sessions for registered entities as necessary as a part of the Training and Education program area.
- 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 54% of its resources on this activity.

Resource Requirements

Personnel

- There is a decrease of one FTE in 2018 from the 2017 budget. This is the result of reprioritization during 2017.

Consultants and contracts

- In 2018, contractor costs will continue to decrease due to the implementation of the risk-based approach. With a risk and performance based assessment of each registered entity, compliance engagements will transition to a periodicity more reflective of the risk profile of the entity such that some will result in audits which are more in-depth while others may have a reduced scope which will result in spot checks or guided self-certifications.

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 2018 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
2017 Budget & Projection, and 2018 Budget
Compliance Monitoring and Enforcement and Organization Registration and Certification

	2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 8,084,046	$ 8,084,046	$ -	$ 7,610,165	$ (473,881)
Penalty Sanctions	-	-	-	41,580	41,580
Total ERO Funding	**$ 8,084,046**	**$ 8,084,046**	**$ -**	**$ 7,651,745**	**$ (432,301)**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 8,084,046**	**$ 8,084,046**	**$ -**	**$ 7,651,745**	**$ (432,301)**
Expenses					
Personnel Expenses					
Salaries	$ 2,749,908	$ 2,667,408	$ (82,500)	$ 2,716,635	$ (33,273)
Payroll Taxes	179,504	172,004	(7,500)	171,841	(7,663)
Benefits	519,457	506,707	(12,750)	524,801	5,344
Retirement Costs	290,486	279,236	(11,250)	282,356	(8,130)
Total Personnel Expenses	**$ 3,739,356**	**$ 3,625,356**	**$ (114,000)**	**$ 3,695,634**	**$ (43,722)**
Meeting Expenses					
Meetings	$ 23,800	$ 23,800	$ -	$ 9,000	$ (14,800)
Travel	329,500	322,750	(6,750)	289,000	(40,500)
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 353,300**	**$ 346,550**	**$ (6,750)**	**$ 298,000**	**$ (55,300)**
Operating Expenses					
Consultants & Contracts	$ 1,274,000	$ 1,274,000	$ -	$ 1,254,000	$ (20,000)
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 1,274,000**	**$ 1,274,000**	**$ -**	**$ 1,254,000**	**$ (20,000)**
Total Direct Expenses	**$ 5,366,656**	**$ 5,245,906**	**$ (120,750)**	**$ 5,247,634**	**$ (119,022)**
Indirect Expenses	**$ 3,282,024**	**$ 3,282,024**	**$ -**	**$ 3,113,668**	**$ (168,356)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 8,648,680**	**$ 8,527,930**	**$ (120,750)**	**$ 8,361,302**	**$ (287,379)**
Change in Assets	**$ (564,634)**	**$ (443,884)**	**$ 120,750**	**$ (709,557)**	**$ (144,922)**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	151,000	151,000	-	40,000	(111,000)
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(73,631)	(73,631)	-	(107,554)	(33,922)
Inc(Dec) in Fixed Assets (C)	**77,369**	**77,369**	**-**	**(67,554)**	**(144,922)**
TOTAL BUDGET (=B+C)	**$ 8,726,049**	**$ 8,605,299**	**$ (120,750)**	**$ 8,293,748**	**$ (432,301)**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (642,003)**	**$ (521,253)**	**$ 120,750**	**$ (642,003)**	**$ 0**

Reliability Assessment and Performance Analysis Program

Reliability Assessment and Performance Analysis Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	5.83	5.83	0.00
Direct Expenses	$2,106,675	$2,145,368	$38,692
Indirect Expenses	$1,125,541	$1,134,543	$9,002
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($25,251)	($39,190)	($13,939)
Total Funding Requirement	$3,206,966	$3,240,721	$33,755

Program Scope and Functional Description

NPCC, through its top technical committee, the Reliability Coordinating Committee (RCC), integrates the deliverables of its Task Force's and Working Group's Reliability Assessment and Performance Analysis related activities. Consistent with the applicable NERC Reliability Standards, these efforts include:

- Reviewing the adequacy of the NPCC systems to supply load considering forecast demand, installed and planned supply and demand resources and required reserves; and,
- Assessing the impact of planned transmission and resource additions or modifications on NPCC system reliability.

Seasonal assessments of the overall NPCC resource adequacy assessments 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.

2018 Key Focus Areas

In collaboration with NERC, Key Focus area activities for 2018 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 (e.g., Long-Term Reliability Assessment, short-term special assessments, probabilistic scenario assessments, and the State of Reliability Report).
- ✓ 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 for ERO activities to identify key

reliability risks and appropriate risk control projects designed to enhance reliability or mitigate risks.

- Developing and tracking of metrics associated with Essential Reliability Services;
- Developing of appropriately tailored analysis and overall assessment, including guidance for registered entities, of high impact, low frequency BES risks, including physical security and geomagnetic disturbance (GMD) vulnerability;
- Providing technical resources to support up to four short-term special reliability assessments (6-18 month horizon replacing the current summer and winter assessments), which focus on specific reliability issue risk areas and geographic areas with specific reliability concerns, while also allowing for regional assessments;
- Supporting the common approach developed for NERC reliability assessments to ensure consistent treatment of resource and reliability evaluations;
- Advancing analytical capabilities for identifying and determining reliability risks and conducting various reliability assessments by:
  - Integrating the analysis and measures of the identified essential reliability services into the NERC 2018 Long-Term Reliability Assessment;
  - Requiring advanced powerflow and stability analysis tools and objective expert input for transmission/deliverability assessments and studies;
  - Maturing and developing interconnection-wide analysis groups to support the assessment of interconnection-wide risks, such as frequency response;
  - Providing technical resources and reliability leadership for the advancement of probabilistic analyses supporting the Long-Term Reliability Assessment;
  - Enhancing the capability for post event analysis, including ensuring the timely and accurate compilation and creation of steady state and dynamic simulation model cases for use in the investigation and analysis of major power system disturbance events.

✓ NPCC supports, through the Eastern Interconnection base case designee agreement, the development of long-term sustainable interconnection-wide powerflow and dynamics model cases under Reliability Standards MOD-032 and MOD-033 that exhibit the accuracy and fidelity reflecting actual BES reliability performance and dynamic conditions.

✓ Provision of technical resources to support the effective and continuous improvement of the models that incorporate recognition of reliability behavior of loads and generation associated with the changing resource mix.

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 Steering Committees. The assessment-related activities indicated for the ERAG Management and Steering Committees below, are done in support of ERO Goal 3: "*Identification and Mitigation of Significant Risks to Reliability*."

In addition, ERAG has the responsibility to facilitate the development of the annual set of seasonal and future steady state and dynamic simulation base cases for use by the Regional Entities and other industry groups in the Eastern Interconnection. This is done through the ERAG Multi-Regional Modeling Working Group (MMWG). The base case compilation and development-related activities indicated for the ERAG Management and MMWG below are done in support of ERO Goal 3 related contributing activity to: "Develop guidelines and industry practices to maintain accurate system models that include the resources (synchronous and inverter based), load, and controllable devises providing essential reliability services." NPCC participates in the ERAG activities as one of the six Eastern Interconnection Regional Entities.

NPCC supports maintenance of the BESnet application and the processing of the Regional BES Exception Requests (ERs), including technical validation of the definition and exception requests periodic reviews of network changes affecting BES determinations, as well as requests for registration and certification reviews. Processing of BES Exception requests and recertification of previously approved BES Exception Requests are not expected to significantly impact resources requirements in this program area for 2018.

NPCC RAPA staff participates with the ERAG Management Committee, ERAG Steering Committee and ERAG Working Group and acts as the liaison between the ERAG MMWG and the NPCC SS-37 Working Group; activities include:

ERAG Management Committee Activities 2018 Goals and Deliverables

- ✓ Oversee the steady state and dynamic simulation base case data compilation and development;
- ✓ Oversee ERAG Multi-Regional Modeling Working Group (MMWG) changes to the dynamics base cases;
- ✓ Oversee MMWG effort to make necessary changes to the modeling of governor-turbine control systems to achieve frequency response that more closely reflects actual response during system frequency deviation events;
- ✓ Oversee the ERAG assessments of anticipated inter-Regional, inter-Balancing Authority transfer limit conditions and sensitivities. ERAG is considering different assessment approaches to enhance the way assessments are conducted to provide more industry value from the assessment results. Coordinate the effort with NERC Assessment Program staff;
- ✓ Develop ERAG Strategic Direction (i.e. anticipated new developments in MMWG process and system assessments); Resolve any issues with application of the ERAG MMWG non-disclosure agreement process so that base cases and assessments have sufficient protections in place for use and transmittal of confidential data and information; and,
- ✓ Develop and approve the ERAG activity budgets.

Multi-Regional Modeling Working Group 2018 Goals and Deliverables

- ✓ Facilitate the completion of the steady state and dynamic simulation base case data compilation and development for the 2018 series of cases. This will include 12 steady state base cases and 8 dynamic simulation base cases;
- ✓ Check and confirm that the dynamic model data passes all applicable checks and acceptance criteria. Include 60 second steady state simulation of each case to detect numerical errors;
- ✓ Apply changes to the MMWG dynamics case so they are available for interconnection dynamics studies;
- ✓ Incorporate dispatch information into the future and seasonal ERAG MMWG base cases so that the dispatches are more closely aligned with economic dispatch practices;
- ✓ Apply the web-based System Dynamics Data Base program during the development of the 2018series of dynamics base cases;
- ✓ Continue to improve the representations of the governor-turbine plant control models at most generators. Recommend the necessary changes in the models for specific generators;
- ✓ 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; and,
- ✓ Verify that procedures in the MMWG manual are followed.

ERAG System Assessments 2018 Goals and Deliverables

- ✓ Conduct the 2018 ERAG Assessments and prepare the ERAG Assessment Reports, including, the assessments of anticipated inter-Regional, inter-Balancing Authority transfer limit conditions and sensitivities;
- ✓ Consider different assessment approaches to enhance the way assessments are conducted; and,
- ✓ 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.

2018 NERC Activities

NPCC will provide the Regional perspective with judicious NPCC RAPA staff participation on selective NERC Planning and Operating Committees and key related NERC Subcommittees, Task Forces and Working Groups which include:

- ✓ Essential Reliability Services Working Group (ERSWG);
- ✓ Load Modeling Task Force (LMTF);
- ✓ Protection System Mis-operations Task Force (PSMTF);
- ✓ Demand Response Availability Data System Working Group (DADSWG);
- ✓ Generating Availability Data System Working Group (GADSWG);
- ✓ Transmission Availability Data System Working Group (TADSWG);
- ✓ Power Plant Model Verification Task Force (PPMVTF);
- ✓ Reliability Assessment Subcommittee (RAS);
- ✓ Probabilistic Assessment Working Group (PAWG);
- ✓ System Analysis and Modeling Subcommittee (SAMS);
- ✓ Performance Analysis Subcommittee (PAS);
- ✓ Misoperation Information Data Analysis System (MIDAS); and,
- ✓ Incorporating any probabilistic reliability metrics required for the 2018 NERC Long-Term Reliability Assessment through the NPCC 2018 Long Range Adequacy Overview.

ERO – Executive Management Group (EMG) 2018 Activities

Provide analytic support for the ERO-EMG:

- ✓ Bulk Electric System Exception Process Working Group (BEPWG);
- ✓ ERO-RAPA Group; and,
- ✓ Other activities as directed by the ERO-Executive Management Group.

2018 Goals and Key Deliverables

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. In addition, the TFCP provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee as requested, and provides support and technical input for related BES risks identified by the NERC Reliability Issues Steering Committee (RISC) and the NERC Essential Reliability Services Working Group.

The Task Force on Coordination of Planning activities indicated below are done in support of 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.*" A related contributing activity to ERO Goal No. 3 is to "Develop advanced and probabilistic methods to evaluate resource adequacy." Related contributing activities associated with ERO Goal No. 4

include "Enhance reliability assessments to reflect changing resource mix behavior, including distributed energy resources and essential reliability services, using probabilistic approaches that consider the variable and energy-limited nature of the evolving resource mix," and "Assess risks associated with cross sector dependencies and single points of disruptions."

TFCP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- Coordinate NPCC responses to 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 developments in the NERC Planning Committee and its Subcommittees are addressed;
- Coordinate the development of additional Criteria as necessary, and track any new and developing standards through the Regional Standards Committee;
- Monitor the development of Bulk Power System (BPS) Regional Standard;
- Oversee NPCC Directory No. 1 Implementation Plan (Dated: September 30, 2015);
- Through the CP-8 Working Group:
    - conduct the annual NPCC Long Range Adequacy Overview and associated NERC RAS requested scenarios and/or special probabilistic studies/assessments;
    - Conduct a review of NPCC Interconnection Assistance Reliability Benefits;
- Evaluate and approve NPCC Area Transmission Reviews;
- Evaluate and approve NPCC Area reviews of Resource Adequacy;
- Coordinate, monitor, review, and make recommendations on the retirement of existing in-service Special Protection Systems (SPS)Remedial Action Schemes (RAS); and the implementation of proposed new or modified SPS/RAS;
- Monitor industry practices and make recommendations to NPCC on transmission adequacy standards related to intermittent generation such as wind or solar-photovoltaic and demand-side resources; and,
- Lead the NPCC Task Forces in the completion of the review and revision the *A10 Criteria–NPCC Classification of Bulk Power System Elements*.

TFCP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- Support related reliability activities, including consideration of any requests for sub-regional assessments or NPCC's identification of the necessity for such assessments consistent with NERC Rules of Procedure section 805, associated with implementation of the State related resource/environmental initiatives;
- Monitor the actions of applicable NERC Subcommittees in the areas of resource adequacy, system protection and system control;
- Through the CP-8 working Group, review the load shape assumption used in NPCCC Multi-Area Probabilistic Reliability Assessments;
- Review and comment on the development of NERC Standards through the RSC;
- Monitor the developments in fuel supply, demand resources, energy efficiency, and conservation methods including all intermittent renewable resources, including embedded distributed resources;
- Support the NPCC Regional Standards Committee (RSC) as required; and,
- Keep informed on studies and developments with neighboring systems which might impact NPCC.

TFCP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- Monitor the process for the annual review and updating of the NPCC Electric System Regional Map and the NPCC Load, Capacity, Energy, Fuel and Transmission Report (LCEF&T);
- Keep informed of the NERC Planning Committee and other subcommittee activities to determine their impact on the NPCC and any potential adjustments to NPCC Criteria;
- Coordinate with NERC regarding the development of standards for dynamic system controls; and,
- 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 certain NPCC documents. In addition, the TFSS provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee, and provides support and technical input for related BES risks identified by the NERC Reliability Issues Steering Committee (RISC) and the NERC Essential Reliability Services Working Group.

The Task Force on System Studies activities indicated below are done in support of 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.*" A related contributing activity to ERO Goal No. 3 is to "Develop guidelines and industry practices to maintain accurate system models that include the resources (synchronous and inverter based), load, and controllable devices providing essential reliability services." A related contributing activity to ERO Goal No. 4 is to "Develop sufficiency/adequacy guidelines for essential reliability services, including considerations of reliability attributes under a more diverse resource mix and changing load behaviors, such as ramping, reserve services and voltage support."

TFSS Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Review and recommend approval of Area Transmission Reviews, in accordance with the "Guidelines and Procedures for NPCC Area Transmission Reviews" (Appendix B of Directory No. 1), based on material presented by the Areas. These reviews assess the impact of planned transmission and resource additions or modifications on system reliability, and determine the Area's conformance with the Basic Criteria. Through the Area Transmission Reviews, re-evaluate the performance and classification of existing SPSs and Dynamic Control Systems;
- ✓ Review and classify new and modified Special Protection Systems and/or Remedial Action Schemes, in accordance with the Appendix B, Procedure for the Review of a Special Protection Systems, of NPCC Directory No. 7, "*Special Protection Systems*";
- ✓ Review and Implement the NPCC A-10 Criteria:
    - Coordinate with TFCP to complete the review and revision of the A-10 document;
    - Review and recommend approval of changes to the NPCC list of bulk power system elements, in accordance with the "*Classification of Bulk Power System Elements*" (Document A-10); and,
    - Update the NPCC BPS List;

- ✓ Review and process Multiple Circuit Tower exclusions in accordance with NPCC Directory No. 1, Appendix E;
- ✓ Update the Multiple Circuit Tower Exclusion List;
- ✓ Perform annual review and update of the Major Project List;
- ✓ Through the SS-37 Working Group:
  - Annually develop a library of power flow base cases and associated dynamic cases. The NPCC cases will also be used to support the development of the library of power flow and dynamic cases for the Eastern Interconnection; in addition: update SS-37 Procedure Manual and other SS-37 documents including the Master Tie Line Data and Interchange Schedule;
  - Provide mid-term updates to the ten-year-out cases in the NPCC Library; and,
  - Perform event replication by benchmarking simulations against actual system performance.
- ✓ Perform the NPCC Under Frequency Load Shedding Assessment;
- ✓ Through the SS-38 Working Group:
  - consider the development of a uniform approach, as requested by TFSP, for identifying BES Elements that meet one or more of the Criteria in R1 of PRC-026-1;
  - Continue to instigate the use of dynamic load models for transient stability studies; and,
  - Work with the NERC Load Modeling Task Force to ensure consistency in load modeling and to share best practices.

TFSS Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ 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 BES risks as identified by the NERC Reliability Issues Steering Committee (RISC);
- ✓ Review existing Regional Criteria and procedures for validation of data used in power flow and dynamic simulations and if the existing criteria or procedures are found to be deficient, propose changes to provide for adequate data validation.
- ✓ Through the SS-38 Working Group:
  - Coordinate management of governor models used in NPCC studies;
  - support the performance of event replication by benchmarking against actual system performance;
  - review and develop comment on draft NERC standards; and,
  - Work with software vendors and NERC systems Analysis and Modeling subcommittee (SAMS) to enhance the capability for dynamic simulations.

Task Force on System Protection

The 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 the protection associated with the bulk power systems. In addition, the TFSP provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee, and provides support and technical input for related BES risks identified by the NERC Reliability Issues Steering Committee (RISC) and the NERC Essential Reliability Services Working Group.

The Task Force on System Protection activities indicated below are done in support of ERO Goal No. 3 "*Identification and Assessment of Significant Risks to Reliability*" and ERO Goal No. 4 "I*dentification and Assessment of Emerging Risks to Reliability*." A related contributing activity to ERO Goal No. 3 is to "Engage industry, forums, and technical committees in identifying and mitigating risks, including reducing misoperations, AC equipment failures, vegetation-related outages, and improving cold weather preparedness and human performance." A related contributing activity to ERO Goal No. 4 is to "Evaluate the reliability impacts of distributed energy resources on planning, operations and restoration and recovery, including the identification of data and information sharing needs."

TFSP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Assess proposed protection systems and special protection systems for compliance with Directory No. 4 and Directory No. 7;
- ✓ Participate 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, as needed;
- ✓ Through the SP-7 Working Group, review misoperations of protection systems and Remedial Action Schemes/Special Protection Systems as they occur in the NPCC Region and participate in providing the NPCC input for the NERC Section 1600 Data Request.
- ✓ Review mitigations and/or progress reports for BPS Risk Reduction Implementation at each meeting and annually report to the RCC on the status of this implementation; and,
- ✓ Provide support and technical input for Task Force related BES risks as identified by the NERC Reliability Issues Steering Committee "RISC". Conduct a thorough review, provide comments as necessary and act on posted materials as directed. Task Force assessments and recommendations will be forwarded to the RCC for approval and submittal to NERC via NPCC Staff and the NERC Risk Control Process.

TFSP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Conduct review/development of the following Documents:
  - Directory No. 7 – "*NPCC Special Protection Systems*." Serve as the lead Task Force working in conjunction with the TFCP and the TFSS on revisions to ensure consistency with the development of the PRC-01202 NERC standard on Remedial Action Schemes.
  - Through the SP-9 Working Group on Telecommunication Circuits Used For Teleprotection and Remidial Action Schemes, develop a new guideline for tele-protection communication reliability.
- ✓ Participate in the ongoing development and submission of NPCC inputs/comments into the development of bulk electric system protection related NERC Reliability Standards;
- ✓ Through the SP-7 Working Group, maintain ongoing log of protection relay failures. Coordinate improved data gathering of relay failures among equipment owners, manufacturers, and vendors;
- ✓ Review and analyze the performance of protection systems of power system disturbances, lessons learned, and events inside as well as outside NPCC as brought to the attention of TFSP by the SP-7 Working Group, NERC Event Analysis Coordinating Group or as requested by the RCC. Issue recommendations for changes to NPCC Documents and lessons learned, as appropriate; and,

- ✓ Support NERC's effort through the ERO-RAPA group to continue relay misoperations performance analysis to reduce protection system misoperations and inform the RCC on relay misoperations trends, and share good practices.

TFSP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Consistent with the TFSP's scope, conduct joint meeting with other Regions to share best practices and experiences.

Task Force on Coordination of Operation

The NPCC Task Force on Coordination of Operation (TFCO) facilitates the coordination of operations among the NPCC Reliability Coordinator areas and adjacent NERC Regions to enhance the reliability of the bulk power system. In addition, the TFCO provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee, and provides support and technical input for related BES risks identified by the NERC Reliability Issues Steering Committee (RISC) and the NERC Essential Reliability Services Working Group.

The Task Force on Coordination of Operation activities indicated below are done in support of 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.*" Related contributing activities related to ERO Goal No.3 include "Conduct assessments of system resiliency and develop guidance for operations in a more secure state;" and ERO Goal No.4 "Evaluate the reliability impacts of distributed energy resources on planning, operations and restoration and recovery, including the identification of data and information sharing needs."

TFCO Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Prepare and conduct the spring and autumn NPCC System Operator Seminars. Provide recommendations to enhance the programs;
- ✓ Develop and securely disseminate the annual compilation of "Facilities for Notification";
- ✓ Support and take part in a biennial, continent-wide Grid Security Exercise (GridEx), 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 incorporating multi-area probabilistic reliability simulation results in each assessment. Coordinate the NPCC input for the annual data for seasonal short-term NERC Reliability Assessments;
- ✓ Conduct reviews of applicable NPCC Directories, Criteria, Guides and Procedures in accordance with their applicable review dates;
- ✓ Coordinate system awareness among NPCC RCs through periodic conference calls. This includes the existing emergency preparedness, NPCC weekly and daily system operator conference calls; and,
- ✓ Monitor the trends and impacts of the changing resource mix and the effects of the proliferation of the new resources on real-time operations, particularly the measures identified in the Essential Reliability Services Framework Report, as well as behavior during and impacts on recovery and restoration plans including consideration of distributed resources, considering the variable and energy-limited nature of the resource shifts.

TFCO Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Review a biennial summary of operating tool failures and lessons learned for the preceding study period;
- ✓ Provide assistance to the NERC Event Analysis process (EAP). Evaluate the operational applicability of Lessons Learned from the NERC EAP; and,
- ✓ Keep informed of the NERC Operating Committee and other subcommittee activities to determine their impact on the NPCC and any potential adjustments to Criteria, as well as provide feedback and input to the respective committees.

TFCO Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Review and analyze the performance of Simultaneous Activation of Reserve (SAR) implementation following an event to enhance the SAR process; and,
- ✓ Share lessons learned among training staff from the NPCC RCs and utilize to make training program enhancements.

NPCC Regulatory/Governmental Affairs Advisory Group

The purpose of the NPCC Regulatory/Governmental Affairs Advisory Group is to promote NPCC interaction and coordination with Federal/State/Provincial governmental and/or regulatory agencies on a coordinated Regional basis, and identify and develop policy input for NPCC and Northeast Regional governmental and/or regulatory bodies.

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 energy and reliability matters.

The Regulatory/Governmental Affairs Advisory Group 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.”

NPCC Regulatory/Governmental Affairs Advisory Group 2018 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). This includes 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 2018.

Reliability Assessment and Performance Analysis Program

Funding sources and related expenses for the Reliability Assessment and Performance Analysis section of the 2018 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
2017 Budget & Projection, and 2018 Budget
Reliability Assessment and Performance Analysis

		2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 3,206,966	$ 3,206,966	$ -	$ 3,225,570	$ 18,604
	Penalty Sanctions	-	-	-	15,151	15,151
Total ERO Funding		**$ 3,206,966**	**$ 3,206,966**	**$ -**	**$ 3,240,721**	**$ 33,755**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 3,206,966**	**$ 3,206,966**	**$ -**	**$ 3,240,721**	**$ 33,755**
Expenses						
Personnel Expenses						
	Salaries	$ 1,084,994	$ 1,084,994	$ -	$ 1,106,772	$ 21,778
	Payroll Taxes	65,373	65,373	-	65,805	432
	Benefits	214,688	214,688	-	220,007	5,319
	Retirement Costs	121,271	121,271	-	117,144	(4,127)
Total Personnel Expenses		**$ 1,486,325**	**$ 1,486,325**	**$ -**	**$ 1,509,728**	**$ 23,402**
Meeting Expenses						
	Meetings	$ 20,500	$ 20,500	$ -	$ 22,000	$ 1,500
	Travel	186,850	186,850	-	212,000	25,150
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 207,350**	**$ 207,350**	**$ -**	**$ 234,000**	**$ 26,650**
Operating Expenses						
	Consultants & Contracts	$ 413,000	$ 413,000	$ -	$ 401,640	$ (11,360)
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
	Depreciation	-	-	-	-	-
Total Operating Expenses		**$ 413,000**	**$ 413,000**	**$ -**	**$ 401,640**	**$ (11,360)**
	Total Direct Expenses	**$ 2,106,675**	**$ 2,106,675**	**$ -**	**$ 2,145,368**	**$ 38,692**
Indirect Expenses		**$ 1,125,541**	**$ 1,125,541**	**$ -**	**$ 1,134,543**	**$ 9,002**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 3,232,217**	**$ 3,232,217**	**$ -**	**$ 3,279,911**	**$ 47,694**
Change in Assets		**$ (25,251)**	**$ (25,251)**	**$ -**	**$ (39,190)**	**$ (13,939)**
Fixed Assets						
	Depreciation	$ -	-	$ -	$ -	$ -
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	(25,251)	(25,251)	-	(39,190)	(13,939)
Inc(Dec) in Fixed Assets (C)		**(25,251)**	**(25,251)**	**-**	**(39,190)**	**(13,939)**
TOTAL BUDGET (=B+C)		3,206,966	3,206,966	-	3,240,721	33,755
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ 0**	**$ 0**	**$ -**	**$ 0**	**$ (0)**

Training, Education, and Operator Certification Program

Training, Education, and Operator Certification Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	0.10	0.10	0.00
Direct Expenses	$229,785	$230,263	$477
Indirect Expenses	$19,306	$19,460	$154
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($433)	($672)	($239)
Total Funding Requirement	$248,658	$249,051	$393

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: 1) potential operational problems for the coming season are discussed, 2) application of NPCC Directory and NERC Standard requirements pertinent to operation are discussed, 3) major industry issues that are important for system operators are discussed, 4) significant disturbances are reviewed for lessons learned and 5) table-top drills and communication and coordination exercises are conducted. The seminars promote camaraderie and better communication among system operators from the NPCC Reliability Coordinator (RC) areas and the Nova Scotia Balancing Authority (BA) area.

This Program also provides for: 1) sharing of RC/BA existing training program and system simulator area content; 2) training techniques and methods; 3, 3) evaluation of new techniques and training and simulator aids as they become available; 4) opportunities to consolidate training among the NPCC RCs and BAs, which includes opportunities to share training material and training sessions; and 5) exchange of information on internal methods of system operator training.

The training activities indicated below are done in support of ERO Goal No. 5 “Effective and Efficient ERO Enterprise Operations.”. A related contributing activity to this goal is to “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

- Provide two high-quality continuing education seminars for system operators;
    - System operators participating in the Seminars: 1) share their approaches to solving 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 3.5 to 4 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 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.
- Implement changes needed for the NPCC Reliability Coordinator / Balancing Authority Areas to meet proposed expanded training requirement for operations support staff in PER-005-2; and,
- 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).

2018 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 class room 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 is considering developing on-line webinars that will focus on a specific topic pertinent to developments related to compliance program implementation, standards development or technical issues.

NPCC also 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 2018 Goals and Deliverables

- Prepare and conduct the 2018 Spring and Fall NPCC System Operator Seminars;
- Implement the PER-005-2 expanded requirements within the NPCC RC/BA Area programs; and,
- Continue collaboration and sharing of the intended RC/BA approaches, experiences and materials to task identification and training development associated with NERC Standard PER-005-2.

Training, Education and Operator Certification 2018 Goals and Deliverables

- As needed, expand 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*"; and,

Develop on-line operational training webinars that focus on specific topics pertinent to related 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 2018.

Training, Education, and Operator Certification Program

Funding sources and related expenses for the training, education, and operator certification section of the 2018 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
2017 Budget & Projection, and 2018 Budget
Training, Education, and Operator Certification

	2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 184,658	$ 184,658	$ -	$ 184,791	$ 133
Penalty Sanctions	-	-	-	260	260
Total ERO Funding	**$ 184,658**	**$ 184,658**	**$ -**	**$ 185,051**	**$ 393**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	64,000	64,000	-	64,000	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 248,658**	**$ 248,658**	**$ -**	**$ 249,051**	**$ 393**
Expenses					
Personnel Expenses					
Salaries	$ 21,012	$ 21,012	$ -	$ 18,399	$ (2,613)
Payroll Taxes	1,396	1,396	-	1,350	(46)
Benefits	4,801	4,801	-	4,893	92
Retirement Costs	2,641	2,641	-	2,320	(321)
Total Personnel Expenses	**$ 29,850**	**$ 29,850**	**$ -**	**$ 26,963**	**$ (2,888)**
Meeting Expenses					
Meetings	$ 186,300	$ 186,300	$ -	$ 188,300	$ 2,000
Travel	13,635	13,635	-	15,000	1,365
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 199,935**	**$ 199,935**	**$ -**	**$ 203,300**	**$ 3,365**
Operating Expenses					
Consultants & Contracts	$ -	$ -	$ -	$ -	$ -
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Direct Expenses	**$ 229,785**	**$ 229,785**	**$ -**	**$ 230,263**	**$ 477**
Indirect Expenses	**$ 19,306**	**$ 19,306**	**$ -**	**$ 19,460**	**$ 154**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 249,091**	**$ 249,091**	**$ -**	**$ 249,723**	**$ 632**
Change in Assets	**$ (433)**	**$ (433)**	**$ -**	**$ (672)**	**$ (239)**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(433)	(433)	-	(672)	(239)
Inc(Dec) in Fixed Assets (C)	**(433)**	**(433)**	**-**	**(672)**	**(239)**
TOTAL BUDGET (=B+C)	248,658	248,658	-	249,051	393
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)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	4.00	5.00	1.00
Direct Expenses	$1,188,137	$1,373,791	$185,654
Indirect Expenses	$772,241	$973,021	$200,780
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($17,325)	($33,611)	($16,286)
Total Funding Requirement	$1,943,053	$2,313,202	$370,148

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 a disturbance does occur, it is critical to use the event as a learning opportunity and provide a forum for the active coordination of reliability and operation among the NPCC Reliability Coordinator areas and neighboring NERC Regions to enhance the reliability of the interconnected bulk power system through the lessons to be 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 "*Identification and Mitigation of Significant Risks to Reliability*." A related contributing activity to this Goal is to "Analyze system performance, events, and relationships among data sources to identify risks and mitigation strategies, and provide recommendations and lessons learned."

Event Analysis Program Description

NERC and the industry follow three avenues in the analysis of a disturbance: the identification of lessons to be learned, a formal cause code analysis and a review of applicable standards.

The Event Analysis Program recognizes that many events which occur on the bulk power system beyond those identified through NERC Reliability Standard EOP-004-2, "Event Reporting," can have varying levels of significance to the electric system, providing otherwise unrealized lessons to be learned from these events and the trending of such events to identify possible reliability concerns. By integrating a "bottom-up" approach to a disturbance 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 or disturbance 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 will perform 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 effort, the entity, the Region and NERC staff will collaborate to assess the NERC Event Analysis Report and perform a formal cause code analysis, identifying a root cause and publish any pertinent lessons learned gathered from the disturbance.

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 of roles and responsibilities of the registered entities, NPCC and NERC in a uniform review of system disturbances by the industry, and, ultimately, the program promotes the 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 disturbances, larger events can be avoided or mitigated.

NPCC staff works step-by-step with the registered entity in 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.

2018 Key Assumptions

- The monitoring of Lessons Learned will continue to be a major focus of NERC in 2018. This will include an added aspect of the voluntary Event Analysis Program, in response to a recommendation of the AC Substation Equipment Task Force (ACSETF), to solicit and collect detailed information on station equipment failures, for applicable, qualifying events to aid in future analysis of station equipment failures to identify trends that may be a threat to the reliability of the BES;
- Critical infrastructure protection will fully integrate the requirements of Version 5 of the Cyber Standards in 2018; and,

- NERC will post updates to the critical infrastructure protection (CIP) 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.

Situation Awareness 2018 Goals and Deliverables

NERC Activities

- NPCC will provide the Regional perspective and support through NPCC EA staff participation on selective NERC Planning and Operating Committees and key related NERC Subcommittees, Task Forces and Working Groups, including:
  Event Analysis Subcommittee (EAS);
  ERO – EA/SA Group; and,
  The Event Analysis Management System (TEAMS).

NPCC Activities

- Work directly with applicable NPCC Task Forces 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);
- Incorporating the Lessons Learned from participation in the GridEx IV wide-area exercise;
- Utilize the NPCC's "what if" methodology to examine an event's potential impact under a different set of system conditions, to evaluate the proximity of a particular event to being a significant BPS requiring appropriate level of analysis with due weight to risk and impact;
- Establish a process/procedure for data capture and transfer aspects for post-disturbance (major disturbance and/or blackout events) system analysis, including requirements for regularly scheduled (annual) testing of the procedure implementation;
- 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 (RCs) within NPCC. Notify the RCs 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 (PSTN), 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 (SA) staff.

Situation Awareness 2018 Goals and Deliverables

Monitor the status of the bulk power system through the NERC Situational Awareness-FERC, NERC, Regions (SAFNR) 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, (TFIST) and include, but are not confined to:

- Providing a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee (CIPC); 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 2018 critical infrastructure goals and objectives, supporting ERO Goal No. 3 - *Identification and Mitigation of Significant Risks to Reliability*." 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 2018 Goals and Deliverables

- Monitor the reliable implementation of the Cyber Security Standards;
- Monitor the Homeland Security Information Network (HSIN), 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 test of cross border emergency telecommunications to verify each Area can communicate with each other;
- Provide support and technical input for Task Force related BES risks as identified by the NERC Reliability Issues Steering Committee "RISC." The Task Force will conduct a thorough review, provide comments as necessary and act on posted materials as directed; and,
- Support the NERC CIPC Grid Exercise Working Group (GEWG) with Cross Sector support in Grid Exercise (GridEx) IV planning and simulation. Participate in the development of lessons learned from GridEx IV.

Critical Infrastructure 2018 Goals and Deliverables

- 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.; and,
- 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 2018 Goals and Deliverables

NPCC's system operations security objectives are defined within the scope of the NPCC Task Force on Coordination of Operation (TFCO) and include, but are not confined 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 assuring cyber security concerns are addressed.

2018.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

- Reallocation of staff during 2017 resulted in an increase of one full time employee in the Situation Awareness and Infrastructure Security program to support increased workload in this area.

Consultants and contracts

- Decrease in consulting and contracts expense is associated with increase in staff allocated to this program area.

Situation Awareness and Infrastructure Security Program

Funding sources and related expenses for the situation awareness and infrastructure security section of the 2018 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
2017 Budget & Projection, and 2018 Budget
Situation Awareness and Infrastructure Security

	2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 1,943,053	$ 1,943,053	$ -	$ 2,300,208	$ 357,155
Penalty Sanctions	-	-	-	12,994	12,994
Total ERO Funding	**$ 1,943,053**	**$ 1,943,053**	**$ -**	**$ 2,313,202**	**$ 370,148**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 1,943,053**	**$ 1,943,053**	**$ -**	**$ 2,313,202**	**$ 370,148**
Expenses					
Personnel Expenses					
Salaries	$ 660,213	$ 742,713	$ 82,500	$ 825,560	$ 165,347
Payroll Taxes	42,778	50,278	7,500	53,677	10,899
Benefits	160,814	173,564	12,750	189,417	28,603
Retirement Costs	72,333	83,583	11,250	87,637	15,304
Total Personnel Expenses	**$ 936,137**	**$ 1,050,137**	**$ 114,000**	**$ 1,156,291**	**$ 220,154**
Meeting Expenses					
Meetings	$ 13,500	$ 13,500	$ -	$ 10,000	$ (3,500)
Travel	78,500	85,250	6,750	87,500	9,000
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 92,000**	**$ 98,750**	**$ 6,750**	**$ 97,500**	**$ 5,500**
Operating Expenses					
Consultants & Contracts	$ 160,000	$ 160,000	$ -	$ 120,000	$ (40,000)
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 160,000**	**$ 160,000**	**$ -**	**$ 120,000**	**$ (40,000)**
Total Direct Expenses	**$ 1,188,137**	**$ 1,188,137**	**$ 120,750**	**$ 1,373,791**	**$ 185,654**
Indirect Expenses	**$ 772,241**	**$ 772,241**	**$ -**	**$ 973,021**	**$ 200,780**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 1,960,378**	**$ 1,960,378**	**$ 120,750**	**$ 2,346,812**	**$ 386,434**
Change in Assets	**$ (17,325)**	**$ (17,325)**	**$ (120,750)**	**$ (33,611)**	**$ (16,286)**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(17,325)	(17,325)	-	(33,611)	(16,286)
Inc(Dec) in Fixed Assets (C)	**(17,325)**	**(17,325)**	**-**	**(33,611)**	**(16,286)**
TOTAL BUDGET (=B+C)	1,943,053	1,943,053	120,750	2,313,202	370,148
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (0)**	**$ (0)**	**$ (120,750)**	**$ 0**	**$ 0**

Administrative Services

Administrative Services Program Resources (in whole dollars)	Direct Expenses and Fixed Assets			FTEs		
	2017 Budget	2018 Budget	Increase (Decrease)	2017 Budget	2018 Budget	Increase (Decrease)
Technical Committees and Members Forum	$72,500	$70,680	($1,820)	0.50	0.50	0.00
General and Administrative	$3,245,691	$3,338,132	$92,441	2.50	2.50	0.00
Legal and Regulatory	$648,680	$592,049	($56,632)	1.00	1.00	0.00
Information Technology	$1,185,675	$1,119,490	($66,186)	2.00	2.00	0.00
Human Resources	$182,059	$181,145	($915)	1.00	1.00	0.00
Finance and Accounting	$525,262	$537,236	$11,974	1.00	1.00	0.00
Total Administrative Services	$5,859,868	$5,838,732	($21,136)	8.00	8.00	0.00

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 2018 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
2017 Budget & Projection, and 2018 Budget
ADMINISTRATIVE SERVICES

	2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ (185,991)	$ (185,991)	$ -	$ 15,823	$ 201,813
Penalty Sanctions	-	-	-	-	-
Total ERO Funding	**$ (185,991)**	**$ (185,991)**	**$ -**	**$ 15,823**	**$ 201,813**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ (185,991)**	**$ (185,991)**	**$ -**	**$ 15,823**	**$ 201,813**
Expenses					
Personnel Expenses					
Salaries	$ 1,872,579	$ 1,872,579	$ -	$ 2,063,139	$ 190,561
Payroll Taxes	93,995	93,995	-	97,378	3,383
Benefits	418,433	418,433	-	438,408	19,975
Retirement Costs	317,471	317,471	-	295,596	(21,874)
Total Personnel Expenses	**$ 2,702,478**	**$ 2,702,478**	**$ -**	**$ 2,894,522**	**$ 192,044**
Meeting Expenses					
Meetings	$ 120,000	$ 120,000	$ -	$ 116,750	$ (3,250)
Travel	143,590	143,590	-	138,000	(5,590)
Conference Calls	37,000	37,000	-	37,000	-
Total Meeting Expenses	**$ 300,590**	**$ 300,590**	**$ -**	**$ 291,750**	**$ (8,840)**
Operating Expenses					
Consultants & Contracts	$ 152,000	$ 152,000	$ -	$ 92,000	$ (60,000)
Office Rent	809,700	809,700	-	810,700	1,000
Office Costs	679,100	679,100	-	664,760	(14,340)
Professional Services	1,041,000	1,041,000	-	960,000	(81,000)
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	50,000	50,000	-	50,000	-
Depreciation	250,000	250,000	-	269,000	19,000
Total Operating Expenses	**$ 2,981,800**	**$ 2,981,800**	**$ -**	**$ 2,846,460**	**$ (135,340)**
Total Direct Expenses	**$ 5,984,868**	**$ 5,984,868**	**$ -**	**$ 6,032,732**	**$ 47,864**
Indirect Expenses	**$ (5,984,868)**	**$ (5,984,868)**	**$ -**	**$ (6,032,732)**	**$ (47,864)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ -**	**$ -**	**$ -**	**$ 0**	**$ 0**
Change in Assets	**$ (185,991)**	**$ (185,991)**	**$ -**	**$ 15,823**	**$ 201,813**
Fixed Assets					
Depreciation	(250,000)	(250,000)	$ -	(269,000)	$ (19,000)
Computer & Software CapEx	125,000	125,000	-	75,000	(50,000)
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	125,000	125,000	-	194,000	69,000
Inc(Dec) in Fixed Assets (C)	**-**	**-**	**-**	**-**	**-**
TOTAL BUDGET (=B+C)	-	-	-	0	0
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (185,991)**	**$ (185,991)**	**$ -**	**$ 15,823**	**$ 201,813**

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.

2018 Key Assumptions

- NPCC's standing committee and subgroup structure for effective stakeholder involvement will continue in 2018
- 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 2018
- 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 2018 Goals and Deliverables

- ✓ The 2018 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 2018 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 2018.

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 2018.

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. In support of ERO Goal 5.c., 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 2018.

Professional Services

- Legal fees are projected to be lower based on additional workload taken on by in-house legal team.

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 2018 Business Plan and Budget assumes agreed-upon ERO Enterprise applications will be available and includes only NPCC costs for region specific support needs.

2018 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.

2018 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 2018.

Human Resources

Program Scope and Functional Description

NPCC has assembled an exceptional team of highly qualified employees to carry out the activities of NPCC. 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

- Temporary office services increased to assist in administrative services in the area of human resources.

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.

2018 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

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

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 2016 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 2016 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 XX% 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 XX% 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 XX% 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.

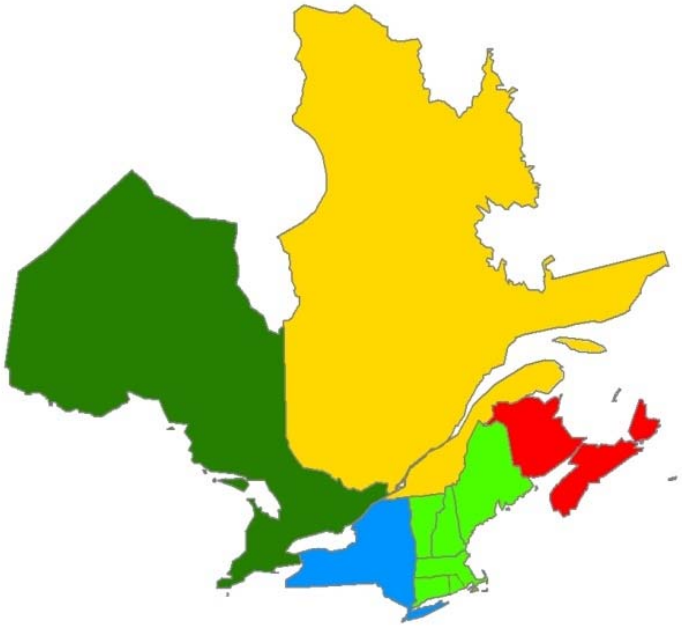
Any penalty monies received from NPCC registered entities within the U.S. by June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs, and then added to the total compliance 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 Quebec 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
2018 Business Plan and Budget



Section B — Supplemental Financial Information

Reserve Balance

Table B-1 Reserve Balance

Working Capital and Operating Reserve Analysis 2017-2018
REGIONAL ENTITY DIVISION

	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Working Capital and Operating Reserve, December 31, 2016	5,327,887	4,069,023	1,258,864	0
Plus: 2017 ERO Funding (from LSEs or designees)	14,255,061	14,255,061		
Plus: 2017 Other funding sources	64,000	64,000		
Less: 2017 Projected expenses & capital expenditures	(15,147,054)	(15,147,054)		
Projected Working Capital and Operating Reserve, December 31, 2017	**4,499,893**	**3,241,030**	**1,258,864**	**0**
Desired Working Capital and Operating Reserve, December 31, 2018 [1]	**2,933,713**	1,674,849 [2]	1,258,864 [3]	
19.42% of Total Regional Entity Budget of $15,106,967				
Desired Business Continuity Reserve, December 31, 2018 [4]	**940,000**			940,000
Less: Projected Working Capital and Operating Reserve, December 31, 2017	(4,499,893)	(3,241,030)	(1,258,864)	
Increase(decrease) in assessments to achieve desired Total Reserve	**(626,180)**	(1,566,180)	0	0

2018 Expenses and Capital Expenditures	15,106,967
Less: Penalty Sanctions [5]	(75,000)
Less: Other Funding Sources	(64,000)
Adjustment to achieve desired Total Reserve balance	(626,180)
2018 Assessment	**14,341,787**

[1] Total Reserve within a range of 16.67% - 33.33% of Budget.
[2] Operating Reserve within a range from 8.33% to 25.00% of Budget. $1,674,849 represents 11.09% of the 2017 budget of $15,106,967
[3] Working Capital equal to 8.33% of Budget. $1,258,864 represents 8.33% of the 2017 budget of $15,106,967
[4] Establish Business Continuity Reserve as approved by the NPCC Board of Directors upon recommendation by the MDCC.
[5] Represents collections July 1, 2016 to June 30, 2017.

Explanation of Changes in Reserve Policy from Prior Year

There was no change to the existing Working Capital and Operating Reserve Policy, however, a separate Business Continuity Reserve (BCR) in the amount of $1,000,000 (allocated between the Regional Entity and Criteria Services divisions) was established 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.

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 2018 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, 2017 are to be used to offset assessments in the 2018 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, 2017 through June 30, 2018 will be used to offset U.S. load serving entity designee assessments in the 2018 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, 2016	Date Received	Amount Received
Penalty Payment 1	12/16/2016	$ 75,000.00
Total Penalties Received		**$ 75,000.00**

Table B-3 Supplemental Funding

Outside Funding Breakdown By Program (excluding ERO Assessments & Penalty Sanctions)	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget
Reliability Standards				
Total	$ -	$ -	$ -	$ -
Compliance Monitoring, Enforcement & Org. Registration				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Reliability Assessment and Performance Analysis				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Training and Education				
Workshops	$ 64,000	$ 64,000	$ 64,000	$ -
Total	$ 64,000	$ 64,000	$ 64,000	$ -
Situation Awareness and Infrastructure Security				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Technical Committees and Member Forums				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Administrative Services Programs				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Total Outside Funding	$ 64,000	$ 64,000	$ 64,000	$ -

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- NPCC assumed no interest income because of continuing low market interest rates.

Table B-4 Personnel Expenses

Personnel Expenses	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Salaries					
Salary	$ 6,718,926	$ 6,718,926	$ 7,057,483	$ 338,557	5.0%
Employment Agency Fees	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Temporary Office Services	$ 30,000	$ 30,000	$ 40,116	$ 10,116	33.7%
Total Salaries	$ 6,758,926	$ 6,758,926	$ 7,107,599	$ 348,673	5.2%
Total Payroll Taxes	$ 404,319	$ 404,319	$ 411,440	$ 7,121	1.8%
Benefits					
Education Reimbursement	$ 22,500	$ 22,500	$ 30,000	$ 7,500	33.3%
Training and Seminars	$ 36,860	$ 36,860	$ 44,232	$ 7,372	20.0%
Medical Insurance	$ 790,034	$ 790,034	$ 811,369	$ 21,335	2.7%
Life-LTD-STD Insurance	$ 88,716	$ 88,716	$ 90,465	$ 1,749	2.0%
Worker's Compensation	$ 15,000	$ 15,000	$ 15,000	$ -	0.0%
Vacation	$ 462,494	$ 462,494	$ 485,312	$ 22,818	4.9%
Relocation	$ -	$ -	$ -	$ -	-
Total Benefits	$ 1,415,603	$ 1,415,603	$ 1,476,378	$ 60,774	4.3%
Retirement					
Pension Contribution	$ 37,000	$ 37,000	$ 38,000	$ 1,000	2.7%
Employee Savings Plan	$ 727,223	$ 727,223	$ 714,353	$ (12,869)	-1.8%
Savings Admin	$ 45,000	$ 45,000	$ 35,000	$ (10,000)	-22.2%
Deferred Compensation	$ 38,000	$ 38,000	$ 38,000	$ -	0.0%
Total Retirement	$ 847,223	$ 847,223	$ 825,353	$ (21,869)	-2.6%
Total Personnel Costs	**$ 9,426,071**	**$ 9,426,071**	**$ 9,820,770**	**$ 394,699**	**4.2%**
FTEs	36.86	36.86	36.86	-	0.0%
Cost per FTE					
Salaries	$ 183,367	$ 183,367	$ 192,827	$ 9,459	5.2%
Payroll Taxes	$ 10,969	$ 10,969	$ 11,162	$ 193	1.8%
Benefits	$ 38,405	$ 38,405	$ 40,054	$ 1,649	4.3%
Retirement	$ 22,985	$ 22,985	$ 22,392	$ (593)	-2.6%
Total Cost per FTE	**$ 255,726**	**$ 255,726**	**$ 266,434**	**$ 10,708**	**4.2%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Temporary office services were increased to provide assistance in administrative services.
- Education reimbursement cost is based on additional employee that has expressed interest in pursuing an advanced degree.
- Savings administration decrease is due to the termination of the defined benefit plan.

Table B-5 Meeting Expense

Meeting Expenses	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Meetings	$ 377,100	$ 377,100	$ 353,050	$ (24,050)	-6.4%
Travel	$ 855,232	$ 855,232	$ 834,500	$ (20,732)	-2.4%
Conference Calls	$ 37,000	$ 37,000	$ 37,000	$ -	0.0%
Total Meeting Expenses	**$ 1,269,332**	**$ 1,269,332**	**$ 1,224,550**	**$ (44,782)**	**-3.5%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Continued efforts to limit the number of attendees to offsite meetings and hold more meetings on-site and via webinar.

Table B-6 Consultants and Contracts

Consultants	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Consultants					
Reliability Standards	$ -	$ -	$ -	$ -	-
Compliance Enforcement and Organization Registration and Certification	$ -	$ -	$ -	$ -	-
Reliability Assessment and Performance Analysis	$ 35,000	$ 35,000	$ -	$ (35,000)	-100.0%
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ -	$ -	$ -	$ -	-
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ 30,000	$ 30,000	$ -	$ (30,000)	-100.0%
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ -	$ -	$ -	$ -	-
Consultants Total	**$ 65,000**	**$ 65,000**	**$ -**	**$ (65,000)**	**-100.0%**

Contracts	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Reliability Standards	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Compliance Enforcement and Organization Registration and Certification	$ 1,274,000	$ 1,274,000	$ 1,254,000	$ (20,000)	-1.6%
Reliability Assessment and Performance Analysis	$ 378,000	$ 378,000	$ 401,640	$ 23,640	6.3%
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ 160,000	$ 160,000	$ 120,000	$ (40,000)	-25.0%
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ 115,000	$ 115,000	$ 85,000	$ (30,000)	-26.1%
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ 7,000	$ 7,000	$ 7,000	$ -	0.0%
Contracts Total	**$ 1,944,000**	**$ 1,944,000**	**$ 1,877,640**	**$ (66,360)**	**-3.4%**
Total Consultants and Contracts	**$ 2,009,000**	**$ 2,009,000**	**$ 1,877,640**	**$ (131,360)**	**-6.5%**

Explanation of Significant Variances –2018 Budget versus 2017 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 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Office Rent	$ 650,000	$ 650,000	$ 650,000	$ -	0.0%
Utilities	$ 43,000	$ 43,000	$ 43,000	$ -	0.0%
Maintenance	$ 40,000	$ 40,000	$ 35,000	$ (5,000)	-12.5%
Security	$ 2,700	$ 2,700	$ 2,700	$ -	0.0%
Real Estate Taxes	$ 74,000	$ 74,000	$ 80,000	$ 6,000	8.1%
Total Office Rent	**$ 809,700**	**$ 809,700**	**$ 810,700**	**$ 1,000**	**0.1%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Projected increase in real estate taxes.

Table B-8 Office Costs

Office Costs	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Telephone	$ 112,000	$ 112,000	$ 111,660	$ (340)	-0.3%
Internet Expense	$ 105,600	$ 105,600	$ 95,000	$ (10,600)	-10.0%
Office Supplies	$ 33,000	$ 33,000	$ 33,000	$ -	0.0%
Computer Supplies and Maintenance	$ 350,000	$ 350,000	$ 350,600	$ 600	0.2%
Subscriptions & Publications	$ 13,500	$ 13,500	$ 13,500	$ -	0.0%
Dues	$ 4,400	$ 4,400	$ 3,400	$ (1,000)	-22.7%
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	$ 6,000	$ 6,000	$ 8,000	$ 2,000	33.3%
Stationary and Office Forms	$ 2,000	$ 2,000	$ 2,000	$ -	0.0%
Equipment Repair/Service Contracts	$ -	$ -	$ -	$ -	-
Bank Charges	$ 15,000	$ 15,000	$ 10,000	$ (5,000)	-33.3%
Sales and Use Tax	$ -	$ -	$ -	$ -	-
Merchant Credit Card Fees	$ -	$ -	$ -	$ -	-
Presentation and Publicity	$ -	$ -	$ -	$ -	-
Total Office Costs	**$ 679,100**	**$ 679,100**	**$ 664,760**	**$ (14,340)**	**-2.1%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

Total Office costs are expected to remain relatively flat.

Table B-9 Professional Services

Professional Services	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
BOT Fee	$ 325,000	$ 325,000	$ 340,000	$ 15,000	4.6%
BOT Search Fee	$ 20,000	$ 20,000	$ -	$ (20,000)	-100.0%
Legal - Reorganization	$ -	$ -	$ -	$ -	-
Accounting & Auditing Fees	$ 310,000	$ 310,000	$ 300,000	$ (10,000)	-3.2%
Legal Fees - Other	$ 316,000	$ 316,000	$ 250,000	$ (66,000)	-20.9%
Insurance - Commercial	$ 70,000	$ 70,000	$ 70,000	$ -	0.0%
Total Services	**$ 1,041,000**	**$ 1,041,000**	**$ 960,000**	**$ (81,000)**	**-7.8%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Legal fees are projected to be lower based on additional workload taken on by in-house legal team.

Table B-10 – Miscellaneous

Miscellaneous Expense	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Miscellaneous Expense	$ 50,000	$ 50,000	$ 50,000	$ -	0.0%
Total Miscellaneous Expense	**$ 50,000**	**$ 50,000**	**$ 50,000**	**$ -**	**0.0%**

Table B-11 Other Non-Operating Expenses

Other Non-Operating Expenses	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Interest Expense	$ -	$ -	$ -	$ -	-
Office Relocation	$ -	$ -	$ -	$ -	-
Total Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**-**

Table B-12 Fixed Assets

Fixed Assets	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Depreciation	$ (250,000)	$ (250,000)	$ (269,000)	$ (19,000)	7.6%
Equipment CapEx	$ -	$ -	$ -	$ -	-
Computer & Software CapEx	$ 276,000	$ 276,000	$ 115,000	$ (161,000)	-58.3%
Furniture & Fixtures CapEx	$ -	$ -	$ -	$ -	-
Leasehold Improvements	$ -	$ -	$ -	$ -	-
Allocation of Fixed Assets	$ -	$ -	$ -	$ -	-
Total Increase (Decrease) in Fixed Assets	**$ 26,000**	**$ 26,000**	**$ (154,000)**	**$ (180,000)**	**-692.3%**

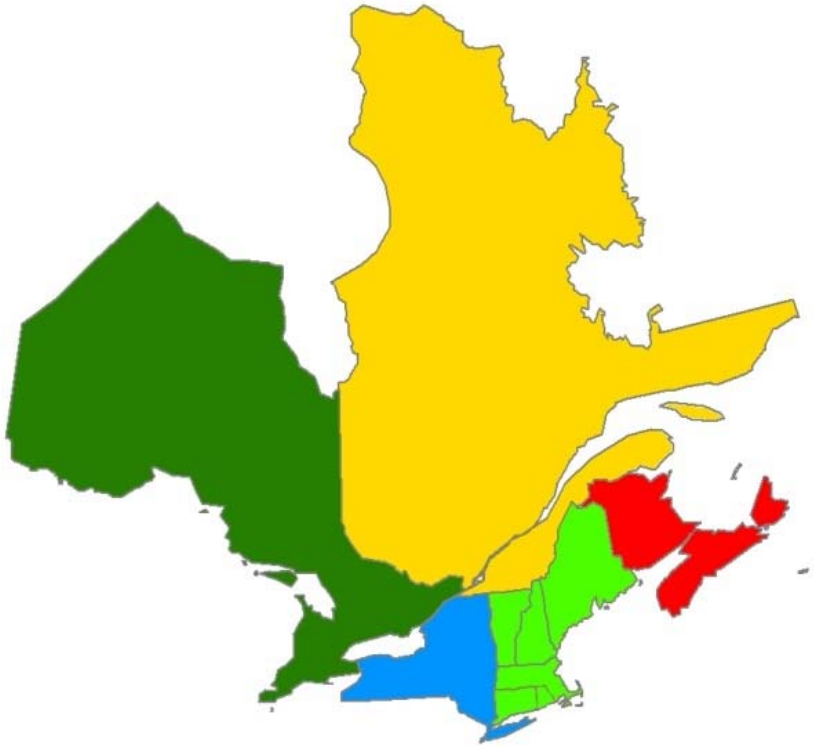
Table B-13 2018 and 2019 Projections

	Table to be Inserted	

Assumptions

Section C – Criteria Services Division Activities

2018 Business Plan and Budget



Section C —2018 Criteria Services Division Business Plan and Budget

Criteria Services Division (in w hole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	2.14	2.14	0.00
Total Direct Expenses	$623,747	$666,530	$42,783
Total Indirect Expenses	$413,149	$416,453	$3,304
Other Non-Operating Expenses	$0	$0	$0
Working Capital and Operating Reserves Requirement	$78,971	($47,843)	($126,813)
Inc(Dec) in Fixed Assets	($10,000)	($16,000)	($6,000)
Funding Requirement	$1,105,867	$1,019,141	($86,726)

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 Regionally-specific more stringent criteria, as well as criteria establishing resource adequacy requirements within the Region. These criteria contain requirements which are more stringent, more specific or augment the existing NERC Reliability Standards requirements. These criteria require continual evaluation to ensure they are "not inconsistent with" any NERC reliability standards as the standards are approved by FERC and the applicable provincial governmental authorities, as per the NERC Rules of Procedure.

Membership and Governance

Full members are subject to compliance with Regionally-specific criteria, in addition to continent-wide Reliability Standards, 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.

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 2018 Assumptions and Cost Impacts

The Criteria Services division services are expected to remain stable throughout 2018

- 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.

2018 Primary Goals and Objectives

- Continue with the development and maintenance of a set of NPCC Directories which are "not inconsistent with" 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 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
    - Continually 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 are "not inconsistent" with, nor 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 2018.
- 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 are "not inconsistent with" the NERC Reliability Standards as mandated by the NERC Rules of Procedure. The conversion of NPCC's 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 "requirement 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 2018, 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 be applied to the existing Directories to make them more consistent with the look of the standards. As NERC standards improve, the need for NPCC Directories and the amount of criteria contained therein will decrease over time, however in the interim, significant review is necessary to ensure the criteria remain "not inconsistent 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 2018.

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 2017.

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 will lead this review and revision.

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.

Directory # 12, *Automatic UFLS Program Requirements*,
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with certain existing NERC and NPCC PRC standard(s). The NPCC Task Force on System Studies will lead this review and revision until such time as the NPCC PRC-006-01 UFLS Regional Standard is approved by the NPCC membership, NERC BOT, the FERC and all the applicable governmental authorities in the Provinces of Canada within NPCC's footprint.

NPCC Criteria Compliance Background

The NPCC criteria services division assures the reliable operation of the bulk power system through implementation of a comprehensive compliance program. This program which includes monitoring, assessing and enforcing compliance with the more stringent, Regionally specific NPCC Criteria requirements, is known as the NPCC Criteria Compliance and Enforcement Program (CCEP) described in process document CCEP-1. This program was developed by the criteria services division and the CCEP Working Group under the purview of the NPCC Compliance Committee. The results of this program support the various Task Forces in their assessments of the NPCC criteria in meeting their goals for the Reliability Coordinating Committee as stated in Section A of this Business Plan.

The more stringent, Regionally-specific NPCC Criteria requirements reflect the unique operational and planning aspects of the bulk power system within the NPCC Region and are included in the NPCC "A" documents and their successors, the NPCC Directories.

NPCC issues non-monetary sanctions to enforce compliance with NPCC Criteria.

- 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*
- On April 5, 2011, the above became effective upon Full Member approval of CCEP-1, and CCEP-2 and retired the following
    - NPCC Criteria A-8, Reliability Compliance and Enforcement Program (RCEP)
    - NPCC Guide B-22, Guidelines for Implementation of the NPCC Inc. Compliance Program
    - NPCC Procedure C-32, Review Process for NPCC Reliability Compliance Enforcement Program
    - Each of the above have been annotated as "retired effective 4/5/11 upon Full Member approval of CCEP-1… and CCEP-2…" on the NPCC public website

- The CCEP-1 document recognizes the applicability of NPCC's Regionally-specific, more stringent reliability criteria to the Full Members of NPCC, consistent with the *Amended and Restated ByLaws*, and respects the provisions of the several Canadian Memoranda of Understanding in the execution of the processes described
- 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
- Describes the roles and responsibilities of Reporting Members, the CC, the RCC and the Enforcement Panel in the compliance review and enforcement process
- Describes Levels of Non-Compliance, associated non-monetary Sanctions, Lateness Policy and the Arbitration/Dispute Resolution process
- Addresses Mitigation Plans for any violations under the enforcement process; and
- Lists the mandatory Certification Forms to be submitted for review by the Task Forces to ensure compliance with NPCC Directories are being met

The CCEP currently requires annual submittal of Certification Forms by the Reliability Coordinators and Balancing Authorities to confirm compliance with various NPCC Directories. Currently the required Certification forms are for Directory #1- *Area Transmission Review*, Directory #8 - *Key Facility List*, Directory #9 – *Generator Real Power Verification*, Directory #10 - *Verification of Generator Gross and Net Reactive Power Capability*, and Directory #12 - *UFLS Program Requirements*. In 2017 NPCC will consider an expansion of the CCEP to include compliance assessment activities to other active Directories.

The CCEP identifies those specific NPCC Directories that are subject to monitoring, assessment and enforcement.

The NPCC Compliance Committee (CC) has final approval of compliance assessments related to CCEP. The CCEP describes the roles and responsibilities of committees and panels used to resolve contested compliance and/or sanction or penalty determinations related to NPCC Directories.

Explanation of Significant Variances – 2018 Budget versus 2017 Budget

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

2017 Budget and Projection and 2018 Budget Comparisons

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget
CRITERIA SERVICES DIVISION

		2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ -	$ -	$ -	$ -	$ -
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Membership Dues	1,105,867	1,105,867	-	1,019,141	(86,726)
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 1,105,867**	**$ 1,105,867**	**$ -**	**$ 1,019,141**	**$ (86,726)**
Expenses						
Personnel Expenses						
	Salaries	$ 401,142	$ 401,142	$ -	$ 404,848	$ 3,706
	Payroll Taxes	23,301	23,301	-	23,413	112
	Benefits	69,100	69,100	-	74,991	5,892
	Retirement Costs	42,605	42,605	-	43,272	667
Total Personnel Expenses		**$ 536,147**	**$ 536,147**	**$ -**	**$ 546,523**	**$ 10,376**
Meeting Expenses						
	Meetings	$ 5,000	$ 5,000	$ -	$ 5,000	$ -
	Travel	51,600	51,600	-	55,647	4,047
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 56,600**	**$ 56,600**	**$ -**	**$ 60,647**	**$ 4,047**
Operating Expenses						
	Consultants & Contracts	$ 18,000	$ 18,000	$ -	$ 40,360	$ 22,360
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	3,000	3,000	-	3,000	-
	Depreciation	10,000	10,000	-	16,000	6,000
Total Operating Expenses		**$ 31,000**	**$ 31,000**	**$ -**	**$ 59,360**	**$ 28,360**
	Total Direct Expenses	**$ 623,747**	**$ 623,747**	**$ -**	**$ 666,530**	**$ 42,783**
Indirect Expenses		**$ 413,149**	**$ 413,149**	**$ -**	**$ 416,453**	**$ 3,304**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,036,896**	**$ 1,036,896**	**$ -**	**$ 1,082,983**	**$ 46,087**
Change in Assets		**$ 68,971**	**$ 68,971**	**$ -**	**$ (63,843)**	**$ (132,813)**
Fixed Assets						
	Depreciation	$ (10,000)	(10,000)	$ -	$ (16,000)	$ (6,000)
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	-	-	-	-	-
Inc(Dec) in Fixed Assets (C)		**(10,000)**	**(10,000)**	**-**	**(16,000)**	**(6,000)**
TOTAL BUDGET (=B+C)		1,026,896	1,026,896	-	1,066,983	40,087
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ 78,971**	**$ 78,971**	**$ -**	**$ (47,843)**	**$ (126,813)**

Personnel Analysis

Total FTE's by Program Area	Budget 2017	Projection 2017	Direct FTEs 2018 Budget	Shared FTEs1 2018 Budget	Total FTEs 2018 Budget	Change from 2017 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 2017 - 2018

Working Capital and Operating Reserve Analysis 2017-2018
CRITERIA SERVICES DIVISION

	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Total Reserve, December 31, 2016	384,529	295,774	88,755	
2017 Non-Statutory Funding (from members)	1,105,867	1,105,867	0	
2017 Other funding sources	0	0	0	
Less: 2017 Projected expenses & fixed asset additions	(1,026,896)	(1,026,896)	0	
Projected Working Capital and Operating Reserve, December 31, 2017	**463,500**	**374,745**	**88,755**	
Desired Working Capital and Operating Reserve, December 31, 2018 [1]	**355,657**	266,746 [2]	88,912 [3]	
Desired Business Continuity Reserve, December 31, 2018	**60,000**			60,000
Less: Projected Working Capital and Operating Reserve, December 31, 2017	(463,500)	(374,745)	(88,755)	
Increase(decrease) in assessments to achieve desired Total Reserve	(47,843)	(107,999)	157	

2018 Funding requirement for expenses and fixed asset additions	1,066,983
Adjustment to achieve desired Working Capital and Operating Reserve balance	(47,843)
2017 Funding and reserve requirement	1,019,141

[1] Total Reserve within a range of 16.67% - 33.33% of Budget.

[2] Total NPCC Operating Reserve must be within a range from 8.33% to 25.00% of Budget. $266,746 represents 25.00% of the 2017 CS budget of $1,066,983.

[3] Total NPCC Working Capital must equal 8.33% of Budget. $88,912 represents 8.33% of the 2017 CS budget of $1,066,983.

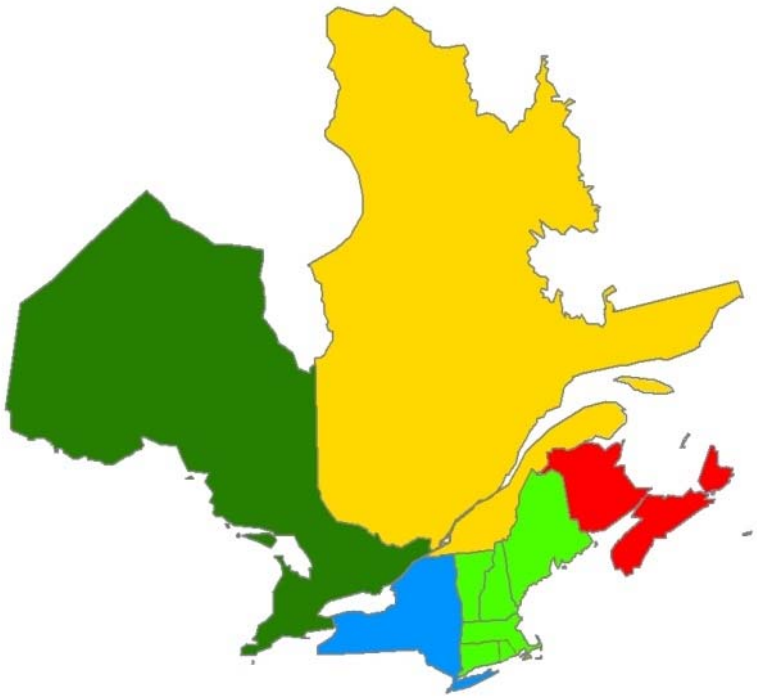
[4] Establish Business Continuity Reserve as approved by the NPCC Board of Directors upon recommendation by the MDCC.

Explanation of Changes in Reserve Policy from Prior Year

There was no change to the existing Working Capital and Operating Reserve Policy, however, a separate Business Continuity Reserve (BCR) in the amount of $1,000,000 (allocated between the Regional Entity and Criteria Services divisions) was established 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.

Section D – Additional Consolidated Financial Statements

2018 Business Plan and Budget



Section D — Additional Financial Statements

Statement of Financial Position

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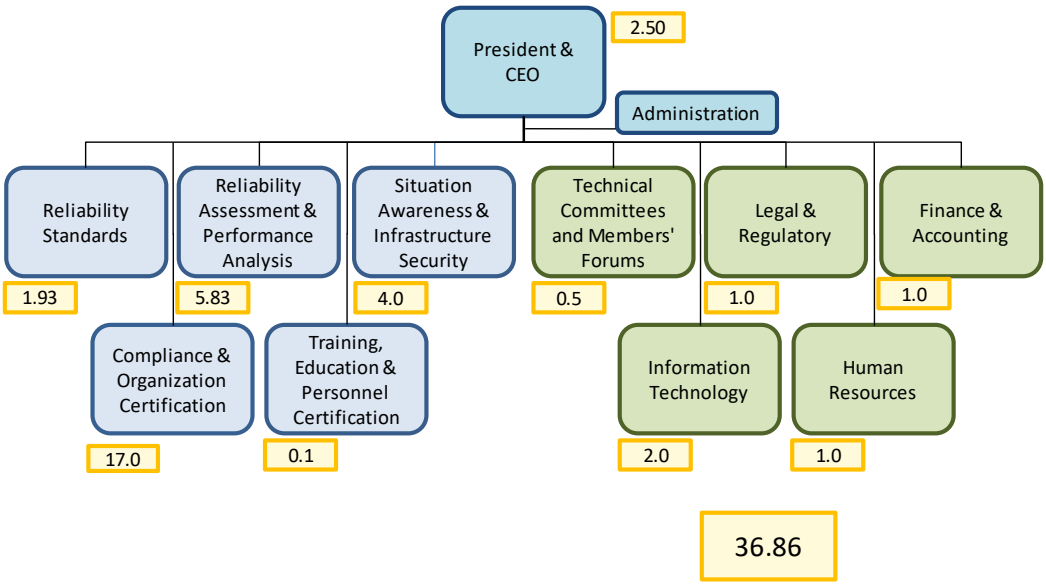
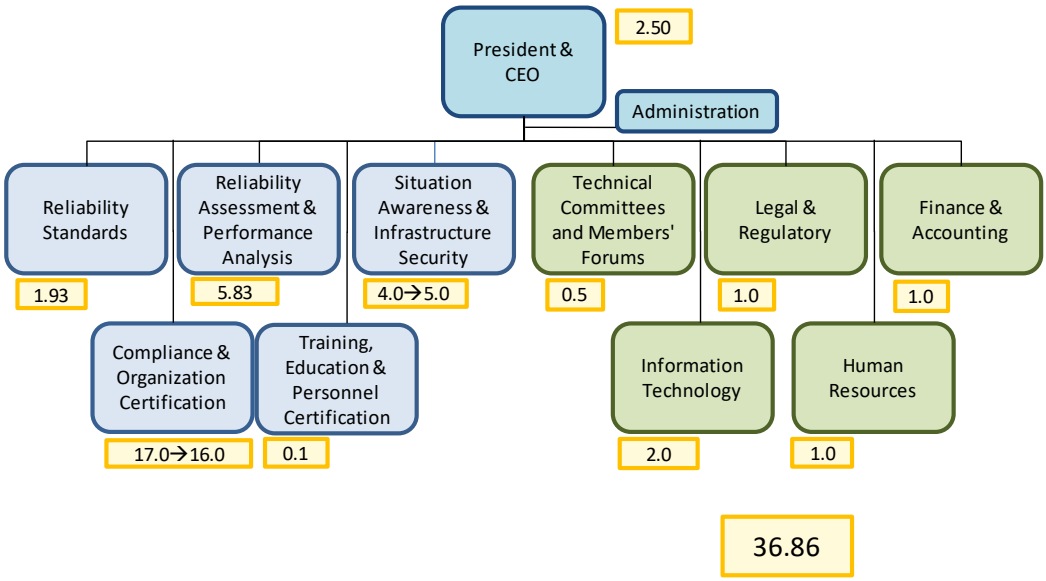
Appendix A Staff Allocations

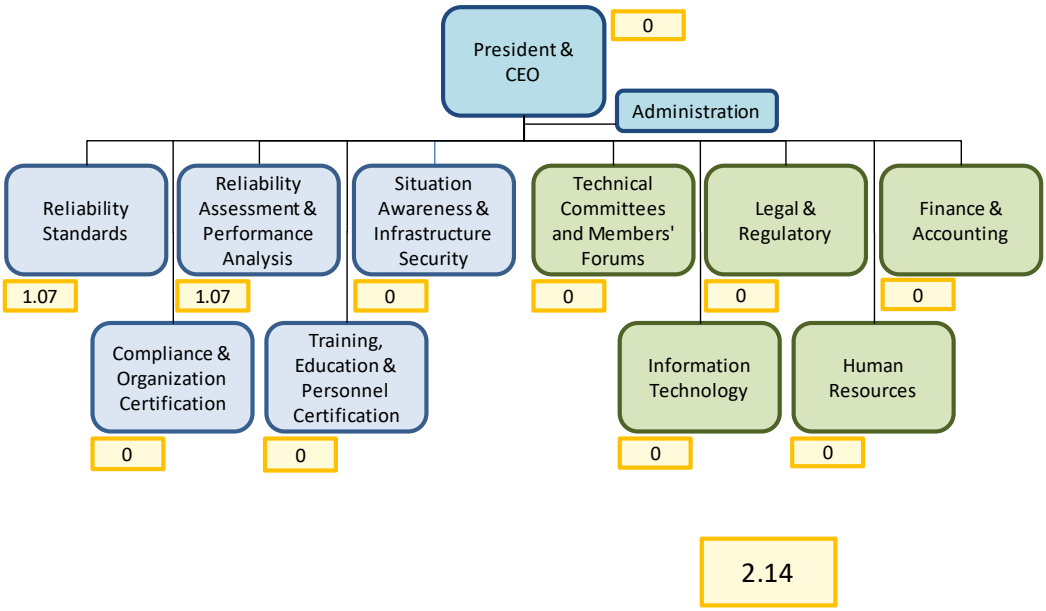
2017 Budget Staff Allocations - RE Division



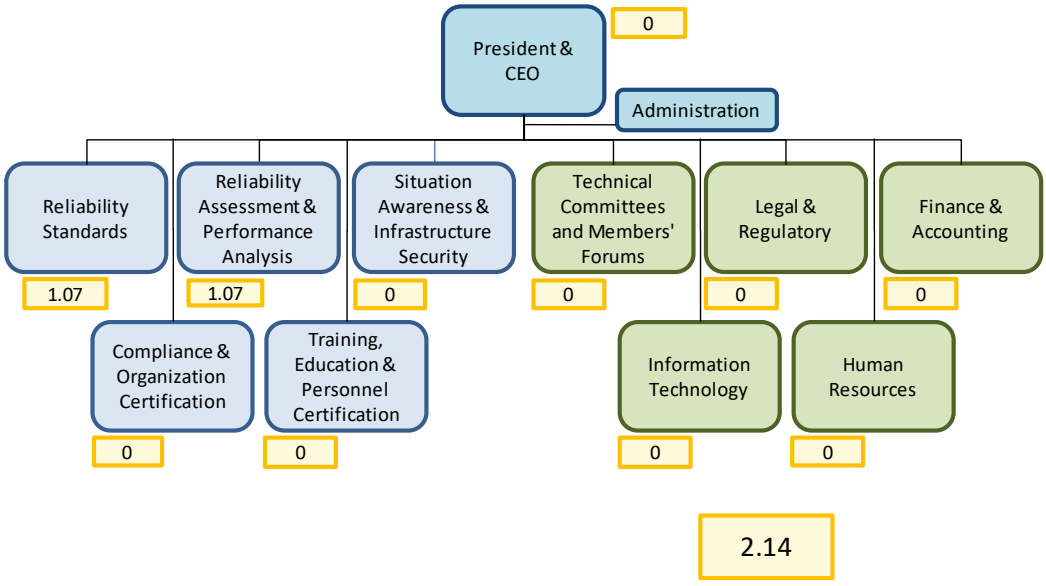
2018 Budget Staff Allocations - RE Division



2017 Budget Staff Allocations - CS Division



2018 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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Peter Brandien
Vice President, System Operations

June 15, 2017

Mr. Edward Schwerdt
Northeast Power Coordinating Council
1040 Avenue of the Americas, 10th Floor
New York, NY 10018

Ed,

I'm writing you today to request that NPCC undertake a comprehensive evaluation of the need for the NPCC regional criteria. ISO New England appreciates NPCC's periodic reviews of existing criteria and the ongoing effort to evaluate the application of NPCC Document A-10, "Classification of Bulk Power System Elements". As noted in the request for comments on the A-10 document, in the past, a key purpose of regional criteria was for NPCC members to "identify their most critical facilities as Bulk Power System elements and hold those facilities to a more stringent, regionally specific set of reliability criteria." That practice has been useful and beneficial to the New England region. However, that practice was developed at a time when there were no mandatory Reliability Standards and continued to be needed to supplement the voluntary national standards that were created. With the passage of the Energy Policy Act of 2005 (EPACT), Reliability Standards are now mandatory, audited, and enforced. Further, in the 12 years since the EPACT of 2005 was passed, the work on ever more comprehensive and stringent Reliability Standards has been continuous. ISO New England believes that the mandatory Reliability Standards, such as the TPL standards, are robust and have supplanted the need for NPCC's regional criteria.

While ISO New England has a number of concerns with the methodology and application described in Document A-10, it is most important to first consider the fundamental purpose that A-10 serves. A-10 defines the means to establish the NPCC Bulk Power System elements to which the regional criteria apply. In the United States, the NERC Reliability Standards apply to the bulk electric system (BES), which is now defined as 100 kV and above. With the establishment of well-vetted Reliability Standards, ISO New England believes that the NPCC Membership should evaluate the cost-effectiveness of NPCC's separate set of regional criteria. Previous reviews of the regional criteria focused on duplications or conflicts with the NERC Reliability Standards but did not evaluate whether there continues to be a need for the regional criteria due to gaps in the NERC Reliability Standards or whether any additional stringency in NPCC's criteria is necessary and/or cost-effective. Therefore, ISO New England believes that NPCC should evaluate which, if any, of the regional criteria are needed in addition to the NERC Reliability Standards. If NPCC Membership determines that these additions to the NERC Reliability Standards are necessary to "provide for reliable operation of the bulk-power system", then NPCC and/or its Members should submit a Standard Authorization Request to NERC.

ISO New England looks forward to working with NPCC and its Members on this evaluation to ensure NERC Reliability Standards provide for an adequate level of reliability.

Sincerely,

Peter Brandien
Vice President, System Operations

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NPCC, Inc.

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

July 14, 2017

Mr. Peter Brandien
Vice President, System Operations
ISO New England, Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Dear Peter,

As I previously indicated in my brief email to you on June 29th, I shared your June 15th letter requesting that NPCC undertake a comprehensive evaluation of the need for and cost-effectiveness of its Regional Criteria with the NPCC Board of Directors. The substance of the letter was discussed as an agenda item at the Board's June 28, 2017 meeting. At the conclusion of that discussion, I was directed to respond to ISO New England's concerns on the Board's behalf, noting several points.

First, as acknowledged in your letter, the NPCC CP-11 Working Group, which contains representatives from ISO-NE, is currently working on the development and evaluation of a more consistent and efficient A-10 methodology for the determination of the most critical facilities within the Northeast, with a goal that uniform implementation of such a methodology would not capture facilities within the NPCC Bulk Power System that are not also included in the FERC approved definition of the Bulk Electric System. Second, NPCC commits to performing a broader review requested by ISO New England in the normal course, even as NPCC continues to review its criteria for any redundancies with new or revised NERC standards. As an example, at the June 28th meeting, the NPCC Board was informed of the retirement of NPCC Directory No. 9 – Generator Real Power Verification and NPCC Directory No. 10 – Generator Reactive Power Verification, as the NERC MOD-025-002 Reliability Standard will achieve the same goals effective July, 2019. Third, the NPCC Board is not ready at this time to consider eliminating the concept of more-stringent, Regionally-specific reliability criteria. Fourth, the Board would be interested in ISO-NE providing input on specific areas of concern or reliability criteria requirements that are at issue. Finally, the Board is cognizant of its limited authorities within the Bylaws regarding criteria, which can only be created, revised or eliminated by vote of the Full Membership.

In closing, both the Board and NPCC staff understand and appreciate ISO New England's concerns and are committed to an orderly, expedited, effective and efficient review of the issues raised.

Thank you for your ongoing support of the reliability of the international interconnected bulk power system within the Northeast and your unwavering commitment to its secure operation. I look forward to continuing this discussion and review.

Sincerely,

Edward A. Schwerdt

Edward A. Schwerdt
President and CEO

CC: NPCC Board of Directors