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 #16-4
August 10, 2016 10:00 a.m. – 5:00 p.m. EST
August 11, 2016 8:00 a.m. – 3:00 p.m. EST
IESO Office
120 Adelaide St West 16th Floor
Toronto, Ontario M5H 1T1
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 June 24, 2016
NPCC Glossary of Terms, dated January 14, 2014

Introductions and Chair's Remarks

NPCC Antitrust Compliance Guidelines

Agenda Items:

1.0 Review of Agenda

2.0 RSC Meeting Minutes

3.0 Drafting Team Members and Executive Tracking Summary

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

4.0 Open Action Items

4.1 Open Action Items List

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin
5.2 NPCC Regional Feedback Mechanism Process
5.3 Functional Model Version 6
5.4 Cost Effectiveness Pilot
5.5 SPS-RAS NPCC Transition
5.6 PRC-025-1 Generator Loadability
5.7 FERC Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities
5.8 Project 2016-03 Cyber Security Supply Chain Management

5.9 NPCC Compliance Guidance Policy – Implementation Guidance

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	8/10/16 Call-In
Project 2013-03 Geomagnetic Disturbance Mitigation Revisions to Project White Papers	6/13/16 (I)	NA	Mark Olson	1:00PM
Enhanced Periodic Review Standing Review Team - Standards Grading	8/1/16 (I)		Mat Bunch	1:15PM
Project 2015-10 Single Points of Failure TPL-001	6/24/16 (I)	SAR	Jordan Mallory	1:30PM
Project 2016-01 Modifications to TOP and IRO Standards	8/3/16 (F)	8/3/16 (I)	Mark Olson	1:45PM
Project 2016-02 Modifications to CIP Standards	9/6/16 (F)	9/6/16 (I)	Al McMeekin Stephen Crutchfield	2:00PM
Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	9/12/16 (F)	9/12/16 (I)	Al McMeekin Stephen Crutchfield	2:00PM
Revisions to the NERC Standard Processes Manual	10/28/15 (I)	NA	Lauren Perotti	2:15PM
Project 2015-09 Establish and Communicate System Operating Limits	8/12/16 (I)	NA	Lacey Ourso	2:30PM
Project 2015-08 Emergency Operations EOP-004-4	9/8/16 (F)	9/8/16 (I)	Sean Cavote Laura Anderson	2:45PM
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 Project 2015-10 Single Points of Failure – TPL-001 SDT

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 Disturbance Monitoring Standard PRC-002-NPCC-01 status update.

8.1.2 Automatic Underfrequency Load Shedding PRC-006-NPCC-02 status update.

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

8.1.4 Geomagnetic Disturbance Mitigation TPL-007-1 Quebec Variance

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* - (status of TFCO review).

9.1.3 Directory#7 *SPS* and NPCC Glossary term SPS - TFSP to consider impact of BOT Approved PRC-012-2 *Remedial Action Schemes* and FERC approved RAS definition.

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

9.1.5 Directory#11 *Disturbance Monitoring Equipment Criteria* – (status of TFSP review).

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

9.1.7 Directory#2 *Emergency Operations*-(status of TFCO review).

9.1.8 Criteria Clarifications;

- Directory#5 *Reserve* – (status of TFCO Clarification).
- Directory#1 *Design and Operation of the BPS* – (status of TFCO Clarification.)

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 21st - Call	March 9th - Meeting	April 20th - Call
June 15th - Meeting	July 20th - Call	September 14th Meeting
October 19th - Call	December 14th - 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/Pages/AgendasHighlightsandMinutes.aspx

13.0 NERC Items of Interest (Since last RSC Meeting)

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

13.1.1 There has been one new Lesson Learned issued since the last RSC meeting.

13.2 Alerts

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

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

13.3 Second Draft of 2017 Business Plan and Budget

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

January 13th – Call	February 17th – Call	March 15-16th Meeting
April 13th – Call	May 10-12th Workshop	June 21-2nd Meeting
July 13th – Call	August 17th – Call	September 20-21st Meeting
October 12th – Call	November 15-17th Workshop	December 8-9th Meeting

14.2 NPCC Board of Directors Meeting (BOD) 2016

February 2nd – Control Center Tour February 3rd - IESO Offices	March 23rd – Call	April 27th – NPCC Offices
June 2nd – Call	June 29th – NPCC Offices	August 3rd - Call
September 7th – NPCC Long Range Strategy Session September 8th – NPCC Offices	October 25th – Call	December 7th – Montreal, Quebec

14.3 NPCC Business Plan and Budget 2017

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2016 Meeting Dates

February 17th-18th, NextEra Energy Offices, Juno Beach FL
April 19th & 20th, NPCC Offices, New York NY
June 22nd & 23rd, Saratoga NY
August 10th & 11th, Toronto Canada
October 5th & 6th, Lewiston NY
December 8th & 9th, Montreal Canada

15.2 RSC 2016 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 8	January 22	February 5
March 4	March 18	April 1
April 29	May 13	May 27
June 10	July 8	July 22
August 5	September 2	September 16
September 30	October 21	November 4
November 18	December 23	

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 #16-3
June 22, 2016 10:00 a.m. – 5:00 p.m. EST
June 23, 2016 8:00 a.m. – 3:00 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**

CC & RSC Joint Meeting Attendees:

	Name	Organization	Sector(s)	Comment
1.	Gerry Dunbar	Northeast Power Coordinating Council		
2.	Ruida Shu	Northeast Power Coordinating Council		
3.	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	
4.	Michael Jones	National Grid	3	
5.	Brian Shanahan	National Grid	1	
6.	Joel Charlebois	AESI, Inc.	Guest	
7	Glen Smith	Entergy Services, Inc.	4	
8.	Kelly Silver	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	
9.	David Ramkalawan	Ontario Power Generation, Inc.	4	
10.	Sylvain Clermont	Hydro-Québec TransÉnergie	1	
11.	Si Truc Phan	Hydro-Québec TransÉnergie	2	
12.	Bruce Metruck	New York Power Authority	6	
13.	Kathleen Goodman	ISO-NE	2	
14.	Vijay Puran	New York State Department of Public Service	6	
15.	Jim Grant	New York Independent System Operator	2	

16.	Payam Farahbakhsh	Hydro One Networks	1	
17.	Dermot Smyth	Consolidated Edison Co. of New York, Inc.	3	Via Phone
18.	Stanley Kopman	Northeast Power Coordinating Council	CC Chair	
19.	Peter Yost	Consolidated Edison Co. of New York, Inc.	CC Vice-Chair	
20.	Esia Giaouris	Hydro One Networks	1	
21.	Vicki O'Leary	National Grid	1	
22.	Deborah Ludden	Velco	1	Via Phone
23.	Kim Moulton	Velco	1	Via Phone
24.	Ed Bedder	Orange and Rockland Utilities, Inc.	1	Via Phone
25.	Randy MacDonald	New Brunswick Power Corporation	2	
26.	Greg Campoli	New York Independent System Operator	2	
27.	Robert Coughlin	ISO-NE	2	
28.	Martin Boisvert	Hydro-Québec TransÉnergie	2	
29.	Scott Berry	IESO	2	
30.	David Burke	Orange and Rockland Utilities, Inc.	3	Via Phone
31.	Sean Bodkin	Dominion Resources Services	4	
32.	Saul Rojas	New York Power Authority	4	
33.	Chris Eaton	Utility Services, Inc.	5	
34.	David Gordon	Massachusetts Municipal	5	
35.	Sal Buffamante	Northeast Power Coordinating Council		
36.	David Cerasoli	Northeast Power Coordinating Council		
37.	Francesco Elmi	Northeast Power Coordinating Council		
38.	Damase Hebert	Northeast Power Coordinating Council		
39.	Walter Cintron	Northeast Power Coordinating Council		
40.	Peter Scalici	Northeast Power Coordinating Council		
41.	Duong Le	Northeast Power Coordinating Council		
42.	Ben Eng	Northeast Power Coordinating Council		

Joint Meeting between CC and RSC:

Stanley Kopman called the joint CC and RSC meeting in order at 10:01AM.

Stanley Kopman introduced the agenda for the joint meeting along with opening remarks.

The joint meeting will be held on June 22nd, 2016 from 10AM-12PM at Hampton Inn & Suites.

1. Compliance Guidance and Section 11 of the Standards Processes Manual.
   Sal Buffamante provided an overview of NERC's Compliance Guidance Policy and explained that Regional Entity Stakeholder Committees are one of the pre-qualified organizations for submitting implementation guidance that NERC reviews and vets to provide such guidance. He also noted that the other compliance guidance methods are CMEP Practice Guides, which provide direction to ERO staff on approaches to carry out compliance monitoring and enforcement activities and which are developed solely by the ERO.
   Ruida Shu provided background on the nature of the changes being proposed to section 11 of the Standards Processes Manual.
   According to the Section 11: Process for Approving Supporting Documents.
   The Standard Committee shall authorize the posting of all supporting references 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 that the document has had stakeholder review to verify the accuracy of the technical content. While the Standard Committee has the authority to approve the posting of each such reference, stakeholders, not the Standard Committee, verify the accuracy of the document's contents.
   Guideline is a recommended process that identifies a method of meeting a requirement under specific conditions.
   CC Members suggested that the CC submit proposed implementation guidance to the RSC for comment prior to submitting to NERC.

2. Enhanced Periodic Review and Standards Metrics.
   Gerry Dunbar provided an update on the Standards Grading activity at NERC. Mr. Dunbar noted a recent NERC webinar on the topic and that the NPCC AVP of Standards Guy Zito has been assigned as the regional representative on the Standing Team along with the Chairs of the NERC Operating Committee, Planning Committee and NERC Staff.
   The leadership of each of these NERC committees and the regional representative will be reviewing standards from selected standard families.
   The team will use a grading methodology formerly used by the NERC Independent Expert Review Team to develop grades for all requirements in the identified set of standards.
   The team is currently finalizing grades which will be posted for a 30 day comment period. Later this year requirement grades will be finalized and provided to Enhanced Periodic Review Teams and incorporated into the Standard Development Plan.

3. Feedback mechanisms from other program areas to improve standards.

Damase Hebert introduced a presentation on the NPCC feedback mechanism which is designed to provide a link between the NPCC compliance and auditing activity and the NERC standard development process via the RSC.
Stanley Kopman noted the difference between the NERC Compliance Guidance Policy and the draft feedback mechanism.
Damase Hebert received questions on potential implementation issues and noted that the proposal was a draft and subject to additional development and comment from the CC and RSC.

4. Disturbance Monitoring Regional Standard – Retirement Status.
   The Disturbance Monitoring Regional Standard PRC-002-NPCC-01 retirement was filed with FERC on June 9, 2016. It was also filed with all Canadian Providences on June 14, 2016.
   The goal is to retire the standard effective July 1, 2016 to coincide with the enforcement date of continent wide PRC-002-3 in order to avoid violations on both standards for a single enforcement action

5. Overall Directory Status/Possible Expansion of CCEP Requirements (2018)
   Stanley Kopman provided an overview of the NPCC Criteria Compliance and Enforcement Program (CCEP). Stanley Kopman explained the program monitors certain criteria from selected Directories. Stanley Kopman noted the pending retirement of two of the Directories currently monitored (Directories #9 and #10) and expressed a desire to expand the CCEP by identifying additional criteria attributes to monitor.
   Stanley Kopman noted that the CC has completed a preliminary review of the criteria in various Directories to identity additional criteria to be monitored . He stated that he would like to expand the CCEP by 2018 and in order to do so the process of finalizing additional criteria and reviewing with the appropriate Task Force needs to begin soon.
   Gerry Dunbar stated that he would be working as the liaison between the CC and the Task Forces.

   Stanley Kopman adjourned the joint CC and RSC meeting at 11:31AM.

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated April 20, 2016
NPCC Glossary of Terms, dated January 14, 2014

	Name	Organization	Sector (s)	Day(s)	Comment
1.	Gerry Dunbar	Northeast Power Coordinating Council		1 & 2	
2.	Ruida Shu	Northeast Power Coordinating Council		1 & 2	
3.	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1 & 2	

4.	Michael Jones	National Grid	3	1 & 2	
5.	Brian Shanahan	National Grid	1	1 & 2	
6.	Joel Charlebois	AESI, Inc.	Guest	1 & 2	
7	Glen Smith	Entergy Services, Inc.	4	1 & 2	
8.	Kelly Silver	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1 & 2	
9.	David Ramkalawan	Ontario Power Generation, Inc.	4	1 & 2	
10.	Sylvain Clermont	Hydro-Québec TransÉnergie	1	1	
11.	Si Truc Phan	Hydro-Québec TransÉnergie	2	1 & 2	
12.	Bruce Metruck	New York Power Authority	6	1 & 2	
13.	Kathleen Goodman	ISO-NE	2	1	
14.	Vijay Puran	New York State Department of Public Service	6	1	Day 2 Via Phone
15.	Jim Grant	New York Independent System Operator	2	1 & 2	
16.	Greg Campoli	New York Independent System Operator	1	1	
17.	Payam Farahbakhsh	Hydro One Networks	1	1	Day 2 Via Phone
18.	Sean Bodkin	Dominion Resources Services	4	1 & 2	
19.	Michele Tondalo	The United Illuminating Company		1	Via Phone
20.	Don Nelson	Commonwealth of Massachusetts DPU/EPD		1 & 2	Via Phone
21.	Ron Falsetti	AESI	Guest	1 & 2	Via Phone
22.	Dermot Smyth	Consolidated Edison Co. of New York, Inc.	4	1	Via Phone
23.	Mark Olson	NERC	Guest	1	Via Phone
24.	Laura Anderson	NERC	Guest	1	Via Phone
25.	Lacey Ourso	NERC	Guest	1	Via Phone
26.	Jordan Mallory	NERC	Guest	1	Via Phone
27.	Lauren Perotti	NERC	Guest	1	Via Phone

Introductions and Chair's Remarks

Bruce Metruck will be retiring from NYPA and ending his membership on RSC.
On behalf of Guy Zito the NPCC AVP of Standards and Chairperson of the RSC, Gerry Dunbar presented Bruce Metruck with a plaque signifying his effort on the Regional Standards Committee and NPCC's deep appreciation of his contributions.

Co Vice Chairpersons Bruce Metruck of NYPA and Si Truc Phan of HQ Co-Chairs of the RSC called the meeting to order in Guy Zito's absence.

NPCC Antitrust Compliance Guidelines

The NPCC Antitrust Compliance Guidelines were read by Ruida Shu.

Agenda Items:

1.0 Review of Agenda

Bruce Metruck reviewed the agenda with the members of RSC.

2.0 RSC Meeting Minutes

Approval of Minutes—there were no additional revisions to the Final Meeting Minutes of 4-19-16.
Herb Schrayshuen made a motion for approval.
Glen Smith seconded the motion.
The Meeting Minutes were approved (all in favor) as documented.

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams

Ruida Shu updated the RSC Members on NERC Drafting Team spreadsheet.

3.2 Executive Tracking Summary

Gerry Dunbar will provide the Directory and Criteria update as part of agenda 9.0.

3.3 NERC Project Tracking Spreadsheet

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

4.0 Open Action Items

4.1 Open Action Items List

Item 4.1 (Coordination with the CC to develop Joint Activity Action List), 4.2 (Coordinate meeting with CC for June 2016 at Saratoga Springs) and 4.5 (Guy Zito sent out Standards Grading Spreadsheet) are completed.
Si Truc Phan of HQ introduced an issue during the review of an outstanding Action Item. He noted that HQ has completed additional studies associated with the impact of GMD in Quebec and stated that this additional information is relevant to the draft standard TPL-007-1 which has been filed with FERC.
As summarized by the NERC standard developer (Mark Olson) (who updated the RSC on Project 2013-03), NERC has recently completed revisions to a project white paper associated with the development of TPL-007-1 and FERC has been holding off its ruling on the standard pending completion of the white paper revisions.

Herb Schrayshuen noted that now that FERC has the additional information it is unclear whether FERC would issue another NOPR or proceed directly to a Final Rule. Si Truc Phan was encouraged to approach FERC with the additional information on behalf of HQT.

Si Truc noted that the standard Drafting Team was aware of the additional information that HQT was working on during the standards development.

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin

5.2 State of Reliability 2016

Herb Schrayshuen mentioned during the FERC Reliability Conference NERC CEO Gerry Cauley indicated that the last major event caused by a process or engineering issue was in 2011. (All other events since that time have been weather related.) Vegetation management and many other aspects of the grid have improved over time as a result of mandatory compliance to the NERC Standards.

5.3 Potential Reliability Impacts of EPA's Clean Power Plan

Gerry Dunbar updated the RSC on the current status of the CPP. NERC completed its Phase 1 review of the CPP which concluded a need for additional implementation timing and a reliability safety valve. The EPA agreed with both of these requests. Currently NERC has completed its Phase 2 review of the CPP and this assessment concludes that the CPP will accelerate the current shift away from coal fired generation towards more natural gas and renewables.
NERC has also established a Task Force to study the impact of these changes.

5.4 MRC

Sylvain Clermont of HQ updated the RSC on recent activity at the NERC Member Representatives Committee (MRC) including 1) Assessing reliability (metrics) 2) ERO Strategic Planning Framework 3) Gas Electric Interdependency.
Comments are due by the end of June 2016 regarding the budget.
There is an approximate increase of 5% on the budget.
There are two initiatives cost effectiveness and Clean Power Plan.
Section 1600 data request on misoperation is in the process of transferring data to the new system MIDAS (Misoperation Information Data Analysis System).

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	6/22/16 Call-In
Project 2013-03 Geomagnetic Disturbance Mitigation Revisions to Project White Papers	6/13/16 (I)	NA	Mark Olson	1:00PM
Project 2015-07 Internal Communications Capabilities	5/9/16 (F)	6/24/16 (F)	Darrel Richardson Laura Anderson	1:15PM
Project 2015-08 Emergency Operations	8/19/15 (I)	SAR	Laura Anderson	1:30PM

Project 2015-09 Establish and Communicate System Operating Limits	9/21/15 (I)	SAR	Lacey Ourso	1:45PM
Project 2015-10 Single Points of Failure TPL-001	6/24/16 (I)	SAR	Jordan Mallory	2:00PM
Project 2016-01 Modifications to TOP and IRO Standards	8/3/16 (F)	8/3/16 (I)	Mark Olson	2:15PM
Project 2016-02 Modifications to CIP Standards	6/30/16 (I)	SAR	Al McMeekin Stephen Crutchfield	2:30PM
Revisions to the NERC Standard Processes Manual	10/28/15 (I)	NA	Lauren Perotti	2:45PM
Draft 2017-2019 Reliability Standards Development Plan	7/19/16 (I)	NA		
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final				

Project 2013-03 Geomagnetic Disturbance Mitigation Revisions to Project White Papers:
Mark Olson called in at 12:58PM.
This project just ended with a 30 day comment period.
One error was identified in the calculations.
A plot in the standard was corrected by the SDT.
It is still well below the IEEE 200A threshold.
Received 14 comments from the industry on the revised white papers.
Industry and stakeholders agreed to the 75A threshold.
The SDT will meet this Friday to discuss and address the comments.
There is a possibility that FERC will issue a directive.

Project 2016-01 Modifications to TOP and IRO standards:
This project is a direct result from a FERC directive Order No. 817.
First directive is regarding monitoring of non BES facilities.
RC's are required to monitor some non BES facilities for SOL exceedance and there are potential gaps if TOP is not included in this requirement.
The SDT recognized the importance of the BES definition.
There might be some facilities that require monitoring and which are not a BES facility.
To ensure all facilities BES and non BES are actively monitored.
Adding to the requirement R10 to include non BES facilities by the SDT.
Second directive is applied to RC, data exchange diversity and redundant capabilities within control center.
The SDT is aware the problem within the data exchange within control center.
There is no control over third party network provide such as AT&T, Verizon etc.
Third directive is regarding testing to the data exchange.
Required RC to test the data exchange capabilities monthly.
Proposed implementation plan is 12 months.

Project 2015-07 Internal Communications Capabilities:
It is under ballot period no further discussion is allowed with NERC.

Project 2015-08 Emergency Operations:
EOP-005, EOP-006 and EOP-008 will be posted prior to the EOP-004.

The SDT received several comments from the industry asking to provide additional clarity on the requirement and reporting document.
The goal is to post the redline documents next week.
EOP standard drafting team leaderships reached out the Department of Energy.
Department of Energy has sent in representation to actively participate with the standard drafting team.
Technical justification will be posted with EOP-004.

Project 2015-09 Establish and Communicate System Operating Limits:
The project involves FAC-010, FAC-011 and FAC-014 standards.
NERC held a technical conference early May 2016.
Early July the SDT is hoping to post a draft redline for an informal comment period.
The SDT is looking to create a new definition for the OPA exceedance and contingences.

Project 2015-10 Single Points of Failure TPL-001:
The project is seeking SC to approve the project so it can be moved onto the solicitation of drafting team members.

Revisions to the NERC Standard Processes Manual:
Three sections of the Standard Processes Manual are being edited, section 6, 7 and 11.
Section 6 is focused on the field testing processes.
NERC is looking to revise section 11 of the NERC Standard Processes Manual.
Section 7 revisions are not posted at the moment.
Herb Schrayshuen seek some additional clarification on the definition between “Guidance” vs “Guideline”.

Project 2016-02 Modifications to CIP Standards:
During the first face to face meeting the SDT is split into several sub teams.
Sub teams have been meeting every week to work on their focused issues and every two weeks there is an all hands meeting with the entire drafting team on Friday.
Five sub teams are:

1. LERC Definition
2. Definitions and Concepts – CA, BCA, ERC, ESP, IRA
3. TO Control Center/Communication Networks
4. Virtualization
5. Transient Cyber Asset at lows

There is another face to face meeting next week in Chicago (Exelon) to draft up the LERC definition.

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

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

7.0 NERC Drafting Team Nominations

7.1 Currently Posted Drafting Team Vacancies

7.1.1 None at this time

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)

7.2.1 None at this time

7.3 Solicitation For Informal Development Teams

7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

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

8.1 Current Activities:

8.1.1 Disturbance Monitoring Standard PRC-002-NPCC-01 status update.

8.1.2 Automatic Underfrequency Load Shedding PRC-006-NPCC-02 status update.

8.1.3 Action Item: Approval of Hydro-Quebec Variance for PRC-006-3 Automatic Underfrequency Load Shedding redline document.

Herb Schrayshuen asked if these changes will have any effect on Hydro Quebec capabilities to export power.

Approval of Posting redline document for Hydro-Quebec Variance for PRC-006-3 Automatic Underfrequency Load Shedding.
Jim Grant made a motion for approval.
Michael Jones seconded the motion.
Redline document for Hydro-Quebec Variance for PRC-006-3 Automatic Underfrequency Load Shedding were approved to post.
Herb Schrayshuen noted that a key question HQ would have to address as part of this proceeding was whether or not these revisions will have an impact on neighboring areas.

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.

TFCO and Working Group CO1 posted revisions to the criteria in order to eliminate battery testing duplicity with FERC approved PRC -005-2 *Protection System Maintenance*. CO1 currently reviewing comments and Directory #8 will likely be posted for a second comment period.

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

TFCO has reviewed the criteria in Directories #9 and #10 and concluded that both Directories can be retired pending the full enforcement date of MOD-025-2 in 2019. Currently a TFCO comparison of the criteria in D#9 and D#10 with the requirements in MOD-025-2 is posted to the Open Process along with a comment form soliciting responses to questions on the TFCO recommendation.

9.1.3 Directory#7 SPS and NPCC Glossary term SPS - TFSP to consider impact of pending RAS PRC-012-2 and FERC approved RAS definition.

Gerry Dunbar updated the RSC on the status of PRC-012-2. Currently the standard has been approved by the NERC BOT and provides for a limited

impact designation for certain RAS's. NPCC attended a pre-filing hearing to address FERC concerns. Pending FERC approval and resolution of any directives, NPCC will examine its criteria in D#7 to ensure that it remains consistent with the standard. Herb Schrayshuen discussed the possibility that FERC may solicit cost estimations associated with eliminating the limited impact designation within PRC-012-2 and encouraged RSC Members who may be impacted to provide FERC with accurate cost estimates for such a scenario.

9.1.4 A-10 status of TFCP review.

TFCP will begin a review of the A-10 methodology later this year. Currently TFCP is soliciting its Members concerns with the A-10 in order to develop a precise scope for the review which will be undertaken by the CP11 Working Group.

9.1.5 Directory#11 Disturbance Monitoring – status.

Directory#11 initial posting has concluded. TFSP will begin its review of comments at its meeting in July.

9.1.6 A-01 Criteria for Review and Approval of Documents – status.

TFCP preparing the A-01 for a posting in the Open Process. TFCP anticipates receiving comments on the approval process for NPCC 'C' documents.

9.1.7 Directory#2 Emergency Operations.

TFCO preparing to review the criteria in D#2. CO8 Working Group currently evaluating criteria in advance of this review.

9.1.8 Status of Task Force Clarifications:

Directory#1 TFCP Clarification regarding use of Tie Benefits in the Area Resource calculations currently posted for comment.

Directory#5 TFCO Clarification regarding the use of storage resources with inverter technology currently posted for comment.

10.0 RSC Member Items of Interest

10.1 RSC Roster

The RSC Members reviewed the current RSC roster for changes.

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 21st - Call	March 9th - Meeting	April 20th - Call
June 15th - Meeting	July 20th - Call	September 14th Meeting
October 19th - Call	December 14th - 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/Pages/AgendasHighlightsandMinutes.aspx

13.0 NERC Items of Interest (Since last RSC Meeting)

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

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

13.2 Alerts

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

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

13.3 2017 Business Plan and Budget

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

January 13th – Call	February 17th – Call	March 15-16th Meeting
April 13th – Call	May 10-12th Workshop	June 21-2nd Meeting
July 13th – Call	August 17th – Call	September 20-21st Meeting
October 12th – Call	November 15-17th Workshop	December 8-9th Meeting

14.2 NPCC Board of Directors Meeting (BOD) 2016

February 2nd – Control Center Tour February 3rd - IESO Offices	March 23rd – Call	April 27th – NPCC Offices
June 2nd – Call	June 29th – NPCC Offices	August 3rd - Call
September 7th – NPCC Long Range Strategy Session September 8th – NPCC Offices	October 25th – Call	December 7th – Montreal, Quebec

14.3 NPCC Business Plan and Budget 2017

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2016 Meeting Dates

February 17th-18th, NextEra Energy Offices, Juno Beach FL
April 19th & 20th, NPCC Offices, New York NY
June 22nd & 23rd, Saratoga NY
August 10th & 11th, Toronto Canada
October 5th & 6th, Boston MA
December 8th & 9th, Montreal Canada

For the October 5th & 6th, RSC meeting will need an alternate location for the meeting. Possible alternate location is NYPA in Niagara Falls.

15.2 RSC 2016 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 8	January 22	February 5
March 4	March 18	April 1
April 29	May 13	May 27
June 10	July 8	July 22
August 5	September 2	September 16
September 30	October 21	November 4
November 18	December 23	

16.0 NYISO Control Room Tour

Greg Campoli of the NYISO conducted a comprehensive review of the NYISO's new map board at the NYISO Control Center.

Highlights of Greg Campoli's review included discussions on the NYISO's use of Phasor Measuring Units (PMU's) and operational coordination issues with neighboring areas. The RSC thanked Greg Campoli and the NYISO for extending its resources to conduct the tour.

The meeting is adjourned on 9:51AM June 23, 2016.

Respectfully Submitted,

Bruce Metruck, Co-Vice Chair RSC
Director, Reliability Standards & Compliance
New York Power Authority

Si Truc Phan, Co-Vice Chair RSC
Engineer – Reliability Standards & Operating Procedures
Hydro-Quebec TransÉnergie

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
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
2007-17.4	PRC-005 FERC Order No. 803 Directive	Standard				
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
2010-05.2	Remedial Action Schemes (Phase 3 of Protection Systems)	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2010-14.1	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				
2013-03	Geomagnetic Disturbance Mitigation	Standard	Emanuel Bernabeu Kenneth Fleischer Luis Marti	PJM NextEra Energy Hydro One Networks	804-432-8780 561-691-2456 416-345-5317	emanuel.e.bernabeu@dom.com kenneth.fleischer@fpl.com luis.marti@hydroone.com
2014-01	Standards Applicability for Dispersed Generation Resources	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.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 Sam Jager	ISO-NE IESO		
2015-04	Alignment of NERC Glossary of Terms and Definitions Used in the	Standard	Jill Loewer	Utility Services		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	Dominion	804-819-2917	connie.lowe@dom.com
2015-09	Establish and Communicate System Operating Limits - FAC-010, F	Standard				
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	Modifications to CIP Standards - CIP-002, CIP-003, CIP-004, CIP-0	Standard	Philippe LaBrosse	Hydro Quebec T.		

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 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 Regional Reliability Standards Executive Tracking Summary

Revised: **9/4/2015**

Further details regarding the individual documents may be found at: http://www.npcc.org/regStandards/UnderDev.aspx

Line No.	Regional Standard ID	Regional Reliability Standard Title	RSAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NPCC BOD Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
1	BPS-501-NPCC-01	Classification of Bulk Power System Elements (Withdrawn by RSC 8/07/09)	Yes (Thru 2/4/08)	NA	NA	NA	NA	NA	NA	NA	Withdrawn by RSC 8/07/09	Withdrawn
2	PRC-002-NPCC-01	Disturbance Monitoring	Yes (Thru 9/10/08)	Yes (Thru 10/24/09)	Yes (Thru 1/6/10)	Yes (1/6/10)	Yes (1/9/10)	Yes (11/4/10)	Yes (5/31/11)	Yes (10/20/11)	10/24/11 - Approved Standard posted publicly	Completed
3	PRC-002-NPCC_02											
4	PRC-006-NPCC-01	Automatic Underfrequency Load Shedding Program	Yes (Thru 8/25/08)	Yes (Thru 11/2/11)	Yes (Pre-ballot Thru 11/2/11)	Yes (11/18/11)	Yes (11/30/11)	Yes (2/9/12)	Yes (5/4/12)	Yes (2/21/13)		Completed
4	PRC-006-NPCC-02	Automatic Underfrequency Load Shedding										Under Development
6	PRC-002-NPCC-02	Disturbance Monitoring	Yes (Thru 2/23/2015)								Regional Standard Authorization Request (RSAR) has been submitted and approved Drafting Team Nomination period ended April 10, 2015	Under Development
7	PRC-002-NPCC-01, Interpretation R1.1		x	x	x	Yes (TFSP 10/19/12)	N/A	N/A	N/A	N/A	Posted on the NPCC website under "Regional Standards General" on 6/24/13	Completed
8	PRC-002-NPCC-01, Interpretation R1.2.2		x	x	x	Yes (TFSP 4/8/13)	N/A	N/A	N/A	N/A	Posted on the NPCC website under "Regional Standards General" on 6/24/13	Completed
7	PRC-002-NPCC-01, Interpretation R4, R5, and R6		x	x	x	Yes (TFSP 5/16/13)	N/A	N/A	N/A	N/A	Posted on the NPCC website under "Regional Standards General" on 6/24/13	Completed
10	BAL-002-NPCC-01	Regional Reserve Sharing	Yes (Thru 11/2/10)	Yes (Thru 12/16/11)	Yes (Thru 1/6/10)						Nomination Form posted - nominations due by 11/10/11	Under Development
11	PRC-012-NPCC-01	Special Protection Systems	Yes (thru 8/18/08)									On Hold
12	Regional Standard Processes Manual	Regional Standard Processes Manual (RSPM)	N/A	Yes (Thru 10/20/13)	Yes (Thru 1/27/14)	Yes (1/27/14)	Yes (3/11/14)				NERC posted the proposed NPCC Regional Standard Processes Manual for a 45-day industry review through 8 p.m. Eastern on Wednesday, May 7, 2014	

x

Acronyms:

RSAR- Regional Standards Authorization Request
RRS- Regional Reliability Standard
DT- Drafting Team
SC - NERC Standards Committee
TBD- To Be Determined
BOD- NPCC Board of Directors
BOT- NERC Board of Trustee

NPCC Document Open Process Executive Tracking Summary

Revised: 7/19/2016

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	Mar-05	TFCP Posted for Comment. Comment Period Ends 8/12/2016.	TFCP to Review and Update in accordance with NRAP.
2	Criteria	A-10	Classification of BPS Elements	Dec-09	TFCP to Review in 2016.	TFCP Developing Scope of Review---CP11 Review to Commence mid 2016.
3	Criteria	A-15	Disturbance Monitoring Equipment Criteria	Aug-07	To be Retired Pending Development of D#11.	Directory#11----TFSP Comment Review Complete. TFSP will Submit to the RCC for Approval.
4	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System	Feb-13		
5	Guideline	B-12	Guidelines for On Line Computer System Performance During Disturbances	Nov-07		
6	Guideline	B-25	Guide to Time Synchronization Substation Equipment	Nov-08		Incorporated into Draft Directory#11 (Appendix A)
7	Guideline	B-26	Guide for Application of Disturbance Recording Equipement	Sep-06		Incorporated into Draft Directory#11 (Appendix B)
8	Guideline	B-27	Regional Critical Asset Identification Methodology	Feb-08	TFIST Retirement Recommendation.	B-27 Retired 6/01/2016.
9	Guideline	B-28	Guide for Generator Sequence of Events Monitoring	Feb-12		Incorporated into Draft Directory#11 (Appendix C)
10	Procedure	C-01	NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures	Jun-16		TFCO Completed Update June 2016.
11	Procedure	C-15	Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems	Jun-16		TFCO Completed Update June 2016.
12	Procedure	C-25	Procedure to Collect Power System Event Data	Sep-07		TFSS to Review and Update for Inclusion in D#11.
13	Procedure	C-29	Procedures for System Modeling:Data Requirements and Facility Ratings	Mar-07	TFSS Revisions.	TFSS Evaluating Comments from Recent Open Process. SS37 to Provide Recommendation on Retirement.
14	Procedure	C-30	Procedure for Task Force on System Protection Review of Disturbances and Protection Misoperations	Dec-09	TFSP Retirement Recommendation.	C-30 Retired 6/01/2016.
15	Procedure	C-33	Procedure for Analysis and Classification of Dynamic Control Systems	Apr-06		
16	Procedure	C-35	NPCC Power System Restoration Guideline	Mar-16		CO11 Currently Reviewing.
17	Procedure	C-39	Procedure to Collect Major Disturbance Event Data	Dec-09	TFSP Retirement Recommendation.	C-39 Retired 6/01/2016.
18	Procedure	C-43	NPCC Operational Review for the Integration of New facilities	Aug-08		
19	Procedure	C-45	Procedure for Analysis and Reporting of Protection System Misoperations	Nov-14		Comment Period Concluded on July 23, 2016. TFSP to Consider Comments.

NPCC Directory Executive Tracking Summary

Revised: 7/19/2016 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 Considering Recommendations/Redlines from CO8 Members Prior to Addressing Review.	
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		
6	Directory #6		Regional Reserve Sharing		Apr-12		
	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.	
	Directory #8	Criteria A-12	System Restoration	TFCO	Oct-10		Subsequent to PRC-005-2 Approval TFCO Revised Battery Testing Criteria. CO11 Considered Comments and Made Further Revisions. TFCO to Repost.
	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 Enforcement of MOD-25-2. Comment Period Concluded on 7/30. TFCO to Consider Comments.
	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	TFCO	Dec-11		See D#9.
	Directory#11	Criteria A-15	Disturbance Monitoring	TFSP	N/A		Initial draft Posted to the Open Process.TFSP Considered Comments and will Present to the RCC for Approval.
	Directory#12		UFLS	TFSS	Oct-12		

NPCC Directory Criteria Clarifications

Revised: **7/19/2016** 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 on October 16th, 2014.	Yes	Interpretation on behalf of IESO-MACD	Complete.
7	Directory#8 Clarification	System Restoration	12/1/2015	TFCO	Yes on June 6th, 2015.	Yes	Clarification on Behalf of OPG.	Complete.
8	Directory#5 Clarification	Reserve		TFCO	Posting Completed July 28th, 2016		Clarification on Behalf of the NYISO.	Pending RCC Approval.

Quarterly Application to the Nova Scotia Utility and Review Board (NSUARB) for Approval of NPCC Regional Reliability Criteria

Revised: **7/19/2016**

Line No.	Filing Period	Filing Due	Filing Submitted	Comments
1	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.
2	January 1 to March 31, 2013	6/1/2013	N/A	No changes were made during the refeenced period which required filing.
3	April 1 to June 30, 2013	9/1/2013	N/A	No changes were made during the referenced period which required filing.
4	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.
5	October 1 to December 31, 2013	3/1/2014	N/A	No changes were made during the referenced period which required filing.
6	January 1 to March 31, 2014	6/1/2014	N/A	No changes were made during the referenced period which required filing.
7	April 1 to June 30, 2014	9/1/2014	N/A	No changes were made during the referenced period which required filing.
8	July 1 to September 30, 2014	12/1/2014	N/A	No changes were made during the referenced period which required filing.
9	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.
10		3/1/2015	N/A	(2) 10/6/14 the RSC approved revisions to the Directory Manual which incorporated cost considerations into the Manual.
11	January 1st to March 31st 2015	6/1/2015	N/A	No changes were made during the referenced period which required filing.
12	April 1st to June 30th 2015	9/1/2015	N/A	No changes were made during the referenced period which required filing.

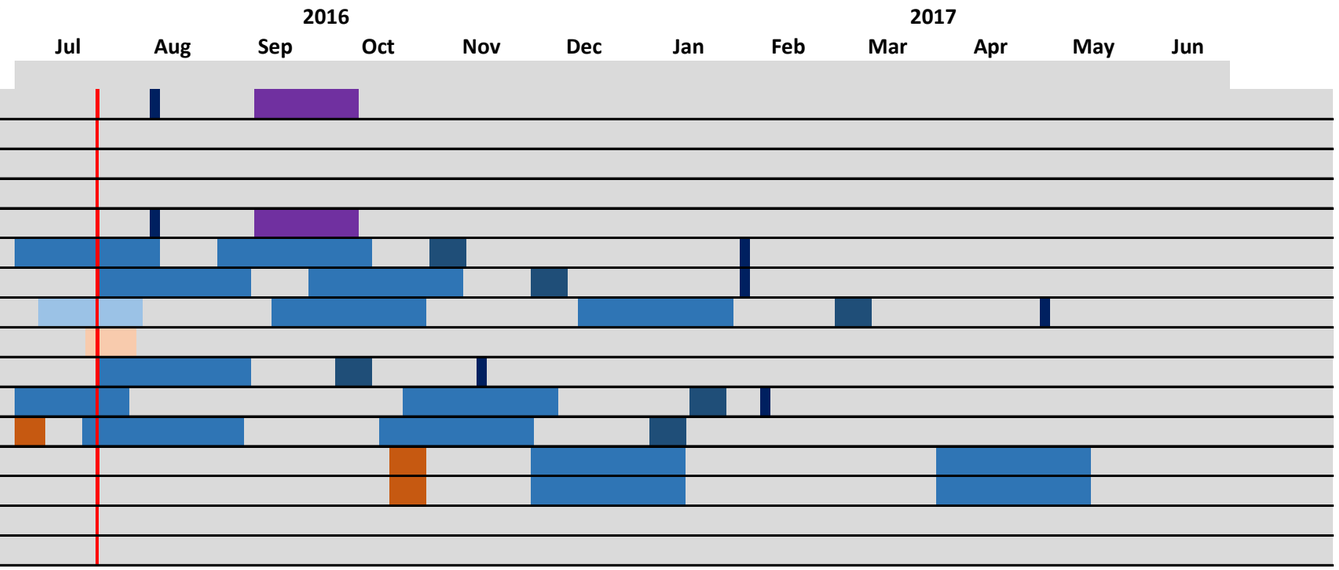
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

SUMMARY
Tutorial Video (11 min)
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Updated: 7/25/2016

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

HOME Project (Filter)	DO NOT SORT (Filtering Ok) Deliverables (Filter)	Early/(Late) Days (Filter)	Baseline/ Current (Filter)
2007-06.2 - Phase 2 System Protection Coordir	PRC-001-1.1.(Ret), PER-006-1 (	69	Current
2010-14.2.2 - Phase 2 of Balancing Authority R	BAL-004	(7)	Current
2013-03 - Geomagnetic Disturbance Mitigatior	TPL-007-1		Current
2015-04 - Alignment of Terms	Report on process (Phase II Im		Current
2015-07 - Internal Communications Capabilitie	COM-001-3	(74)	Current
2015-08 - Emergency Operations	EOP-005, EOP-006, and EOP-0(	(148)	Current
2015-08 - Emergency Operations	EOP-004	(101)	Current
2015-09 - Establish and Communicate System (	FAC-010-3, FAC-011-3, and FA(	(58)	Current
2015-10 - Single Points of Failure TPL-001	TPL-001		Current
2015-INT-01 - Interpretation of CIP-002-5.1 for	Interpretation CIP-002-5.1		Current
2016-01 - Modifications to TOP and IRO Standa	TOP/IRO Standards		Current
2016-02 - Modifications to CIP Standards	LERC Definition		Current
2016-02 - Modifications to CIP Standards	Directives, Control Center Com		Current
2016-02 - Modifications to CIP Standards	V5TAG, CA and BCA Definitions		Current
2016-EPR-01 - Enhanced Periodic Review of Pe	PER Stds.		Current
2016-EPR-02 - Enhanced Periodic Review of Vc	VAR-001-4.1 & VAR-002-4		Current



Project	Project Name	Status	Comments	Deliverable	Deadline	Priority in 2016-2018 RSDP, if applicable (see Note 1)	P81 Req (2013)	Number of Directives	No. of Guidances (see Note 2)	Directionally consistent with IERP findings (See Note 5)	Developer	PMOS Liaison
2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Pending Board Adoption	NERC staff are working on communicating the retirement to industry, including the Operating Committee, before presenting to the Board.	BAL-004	N/A	N/A	N/A	N/A	4	N/A	Darrel Richardson	Ken Goldsmith
2013-03	Geomagnetic Disturbance Mitigation	Pending Regulatory Approval	NOPR issued May 14, 2015. FERC established additional comment period in October 2015 for responses to material filed following NOPR comments. FERC Staff technical conference held Mar 2016. Pending Final Rule. NERC filed notice in April 2016 of plans to submit correction to project white papers. White papers are posted until June 13, 2016.	TPL-007-1	N/A	N/A	N/A	N/A	N/A	N/A	Mark Olson	Jennifer Sterling
2015-04	Alignment of Terms	Other	SDT is developing recommendations to present to SC.	Report on process (Phase II Improvement Report)	N/A	N/A	N/A	N/A	N/A	N/A	Lacey Ourso	Andrew Gallo
2015-07	Internal Communications Capabilities	Working to Final Ballot	Expected posting the week of June 13.	COM-001-3	N/A	HIGH	N/A	1	N/A	N/A	Darrel Richardson	Brenda Hampton
2015-08	Emergency Operations	Posted	Posted for a 45-day initial comment period and ballot.	EOP-005, EOP-006, and EOP-008	N/A	Medium	N/A	1	N/A	N/A	Laura Anderson	Ken Goldsmith
2015-08	Emergency Operations	Working to Initial Posting	Planning to post for an initial comment and ballot in late July 2016.	EOP-004	N/A	Medium	N/A	1	N/A	N/A	Laura Anderson	Ken Goldsmith
2015-09	Establish and Communicate System Operating Limits	Working to Initial Ballot	We are planning on posting for a 30-day informal comment period sometime in July. As of now, we are looking at July 8 (Fri) – August 8 (Mon). The plan is to obtain initial industry feedback through the informal comment period, and then (hopefully) have our draft standard ready in time to go to the September 14 Standards Committee meeting to request authorization for our initial 45 day formal comment and ballot period, which would occur September 15 (Th) – October 31 (Mon). All of this is still tentative, but I will know more after the meeting the week of June 20, 2016.	FAC-010-3, FAC-011-3, and FAC-014-2	N/A	Medium	N/A	N/A	N/A	N/A	Lacey Ourso	Andrew Gallo
2015-10	Single Points of Failure TPL-001	Nominations	Revisions made to the SAR at the March 21-23, 2016 SAR ST meeting. Revisions are adding two outstanding FERC Directives from Order 786 (p. 40 and 89). Additionally, the retired MOD standards stated in TPL-001-4 Requirement R1 will be updated with the current MOD standard. The SAR is currently out for a 30-day informal comment period (May 26-June 24). A projected schedule has not been set by the SDT.	TPL-001	N/A	High	N/A	N/A	N/A	N/A	Jordan Mallory / Al McMeekin	Mark Pratt
2015-INT-01	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	Working to Initial Ballot	SC approved RFI and for a project team to be formed in April 2016. The CIP SDT under Project 2016-02 is addressing this RFI.	Interpretation CIP-002-5.1	N/A	N/A	N/A	N/A	N/A	N/A	Stephen Crutchfield	Brian Murphy
2016-01	Modifications to TOP and IRO Standards	Posted	NOPR issued June 18, 2015 (under previous project 2014-03). Final Rule issued November 19, 2015 with three directives with an associated 18 month regulatory filing deadline. The SC authorized posting at the June 2016 SC meeting.	TOP/IRO Standards	FERC deadline of May 19, 2017.	N/A	N/A	N/A	N/A	N/A	Mark Olson	Rod Kinard
2016-02	Modifications to CIP Standards	Posted	Currently in initial comment and ballot.	LERC Definition	Directive: March 30, 2017 (LERC only)	High	N/A	1	N/A	N/A	Stephen Crutchfield / Al McMeekin	Brian Murphy
2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	Standing Review Team	Project is on hold until the SC Standing Review Team completes their grading and 30 day posting. Project expected to kick-off in September 2016.	PER Stds.	N/A	N/A	N/A	N/A	N/A	N/A	Darrel Richardson	Mike Brytowski
2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive Standards	Standing Review Team	Project is on hold until the SC Standing Review Team completes their grading and 30 day posting. Project expected to kick-off in September 2016.	VAR-001-4.1 & VAR-002-4	N/A	N/A	N/A	N/A	N/A	N/A	Scott Barfield-McGinnis	Amy Casuscelli

ARCHIVE SUMMARY		(Sorting okay)
Project	**Project Name**	**Status**
2007-06.2	Phase 2 System Protection Coordination	Adoption by Board
2009-02	Real-time Reliability Monitoring and Analysis Capabilities	Pending Regulatory Approval
2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls – BAL-005, BAL-006, FAC-001	Pending Regulatory Filing
2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls – BAL-005, BAL-006, FAC-001	Pending Regulatory Filing
2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls – BAL-005, BAL-006, FAC-001	Pending Regulatory Filing
2015-INT-02	Interpretation of CIP-007-5 for Foxguard Solutions	Inactive
2015-INT-03	Interpretation of TOP-002-2.1b for FMPP	Inactive

Comments	**Deliverable**
The standard passed overwhelmingly along with the definitions. Headed to BOT in August 2016.	PRC-001-1.1.(Ret), PER-006-1 (New), and revision to definitions of Operational Planning Analysis and Real-time Assessment
0	New IRO-018-1 and TOP-010-1
Passed final ballot with 72% approval February 2016. Adopted by NERC BOT in February 2016. Filed with FERC in April 2016.	BAL-005
Passed final ballot with 80% approval February 2016. Adopted by NERC BOT in February 2016. Filed with FERC in April 2016.	FAC-001
Passed final ballot with 94% approval February 2016. Adopted by NERC BOT in February 2016. Filed with FERC in April 2016.	BAL-006
Currently on hold. SC approved RFI and for the interpretation drafting team to be formed in April 2016.	CIP-007-5
Currently on hold. Interpretation drafting team recommendations were submitted to the SC in February 2016.	TOP-002-2.1b

Deadline	**Priority in 2016-2018 RSDP, if applicable (see Note 1)**	**P81 Req (2013)**	**Number of Directives**	**No. of Guidances (see Note 2)**	**Directionally consistent with IERP findings (See Note 5)**
NERC-imposed deadline of 12/31/2015	N/A	1 - Move PRC-001, R1 to Training	6	1	Yes - PRC-001-1.1(ii), R1 was noted as duplicative of TOP-006-2 R3, but TOP-006 was retired without addressing R1 under TOP/IRO in 2015.
N/A	N/A	N/A	3	N/A	N/A
N/A	N/A	N/A	N/A	4	N/A
N/A	N/A	11	7	1	N/A
N/A	N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A

	HOME	
Developer	**PMOS Liaison**	
Scott Barfield-McGinnis	Brenda Hampton	
Mark Olson	Jennifer Sterling	
Darrel Richardson	Ken Goldsmith	
Darrel Richardson	Ken Goldsmith	
Darrel Richardson	Ken Goldsmith	
Lacey Ourso	Brian Murphy	
Lacey Ourso	Brian Murphy	

Project	**2007-06.2**
Project Name	Phase 2 System Protection Coordination
Status	Adoption by Board
Comments	The standard passed overwhelmingly along with the definitions. Headed to BOT in August 2016.
Deliverable	PRC-001-1.1.(Ret), PER-006-1 (New), and revision to definitions of Operational Planning Analysis a
Deadline	NERC-imposed deadline of 12/31/2015
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	1 - Move PRC-001, R1 to Training
Number of Directives	6
No. of Guidances (see Note 2)	1
Directionally consistent with IERP findings (See Note 5)	Yes - PRC-001-1.1(ii), R1 was noted as duplicative of TOP-006-2 R3, but TOP-006 was retired without addressing R1 under TOP/IRO in 2015.
Developer	Scott Barfield-McGinnis
PMOS Liaison	Brenda Hampton
Affected Standards	PRC-001-1.1.(ret.), PER-006-1 (new)

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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							
Nominations - DT	1/6/2015	1/20/2015	1/30/2015	2/13/2015	24		
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/11/2007	7/10/2007	6/11/2007	7/10/2007			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	7/29/2015	9/11/2015	5/11/2015	6/25/2015	(79)	Regulatory Meeting	62.55%
CAB - Com/Add Ballot 2	10/6/2015	11/19/2015	7/27/2015	9/10/2015	(71)	Baseline Reset	57.29%
CAB - Com/Add Ballot 3	3/10/2016	4/30/2016	2/14/2016	3/30/2016	(25)	Change in Approach	80.57%
CAB - Com/Add Ballot 4			6/1/2016	7/16/2016		Not needed	

CAB - Com/Add Ballot 5							
FB - Final Ballot	5/17/2016	5/26/2016	7/25/2016	8/4/2016	69		82.52%
PTB - Present to BOT	8/10/2016	8/12/2016	8/10/2016	8/12/2016			
Filing - Filing with Regulators	9/10/2016	10/10/2016	9/10/2016	10/10/2016			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Explain the delay	5/1/2015	Did not pass Septmber 2015 ballot and will plan to conduct another SDT meeting and post for additional ballot. Goal to post end of January 2016; however, the SDT's plan to present a PER-005-2 revision met industry opposition during informal outreach. The SDT held a technical conference to resolve - resulting in PER-006-1 and definition changes to OPA and RTA. The first formal comment period for PER-006-1 runs March 10 to April 25 with an initial ballot.
Explain early finish	6/1/2016	PER-006-1 did not require an additional planned ballot, passed on initial.

Project	**2010-14.2.2**
Project Name	Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2
Status	Pending Board Adoption
Comments	NERC staff are working on communicating the retirement to industry, including the Operating Committee, before presenting to the Board.
Deliverable	BAL-004
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	4
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Darrel Richardson
PMOS Liaison	Ken Goldsmith
Affected Standards	BAL-004

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	3/17/2015	4/15/2015	1/15/2015	2/14/2015	(61)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	8/12/2015	8/25/2015	4/1/2015	5/1/2015	(133)		
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/24/2015	11/12/2015	10/1/2015	11/15/2015	7		
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							

CAB - Com/Add Ballot 5							
FB - Final Ballot	12/8/2015	12/17/2015	12/1/2015	12/11/2015	(7)		
PTB - Present to BOT	2/10/2016	2/12/2016	5/1/2016	5/3/2016	81		
Filing - Filing with Regulators			6/1/2016	6/11/2016			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes

Project	**2013-03**
Project Name	Geomagnetic Disturbance Mitigation
Status	Pending Regulatory Approval
Comments	NOPR issued May 14, 2015. FERC established additional comment period in October 2015 for responses to material filed following NOPR comments. FERC Staff technical conference held Mar 2016. Pending Final Rule. NERC filed notice in April 2016 of plans to submit correction to project white papers. White papers are posted until June 13, 2016.
Deliverable	TPL-007-1
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mark Olson
PMOS Liaison	Jennifer Sterling
Affected Standards	TPL-007-1

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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							
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
No dates provided	6/1/2016	Project finished prior to 2015.

Project	**2015-04**
Project Name	Alignment of Terms
Status	Other
Comments	SDT is developing recommendations to present to SC.
Deliverable	Report on process (Phase II Improvement Report)
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Lacey Ourso
PMOS Liaison	Andrew Gallo
Affected Standards	Glossary/ROP

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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							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

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

PTS Change Control

Reason for Update	Date	Notes

Project	**2015-07**
Project Name	Internal Communications Capabilities
Status	Working to Final Ballot
Comments	Expected posting the week of June 13.
Deliverable	COM-001-3
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	HIGH
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	Darrel Richardson
PMOS Liaison	Brenda Hampton
Affected Standards	COM-001-3

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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							
Nominations - DT	6/11/2015	6/24/2015	6/1/2015	6/15/2015	(10)		
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/11/2015	7/11/2015	6/1/2015	7/1/2015	(10)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/25/2015	11/16/2015	7/15/2015	8/29/2015	(72)		
CAB - Com/Add Ballot 2	3/23/2016	5/9/2016	10/1/2015	11/15/2015	(174)		
CAB - Com/Add Ballot 3			1/1/2016	2/15/2016		Not needed	
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	6/14/2016	6/24/2016	4/1/2016	4/11/2016	(74)		83.25%
PTB - Present to BOT	8/10/2016	8/12/2016	5/6/2016	5/8/2016	(96)		
Filing - Filing with Regulators	8/10/2016	8/12/2016	8/10/2016	8/12/2016			
PT - Post Approval Training	9/10/2016	10/10/2016	9/10/2016	10/10/2016			

PTS Change Control

Reason for Update	Date	Notes
Update to SC	6/15/2016	Update given to SC concerning delay.

Project	**2015-08**
Project Name	Emergency Operations
Status	Posted
Comments	Posted for a 45-day initial comment period and ballot.
Deliverable	EOP-005, EOP-006, and EOP-008
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	Medium
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	Laura Anderson
PMOS Liaison	Ken Goldsmith
Affected Standards	EOP-005, EOP-006, and EOP-008

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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							
Nominations - DT							
QR - Quality Review			1/11/2016	1/21/2016			
SP1 - SAR/PR/WP Posting 1	7/21/2015	8/19/2015	7/15/2015	8/14/2015	(6)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	***6/29/2016***	***8/12/2016***	***1/25/2016***	***3/10/2016***	(156)		
CAB - Com/Add Ballot 2	8/30/2016	10/14/2016	4/4/2016	5/19/2016	(148)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	11/1/2016	11/11/2016	6/6/2016	6/16/2016	(148)		
PTB - Present to BOT	2/1/2017	2/3/2017	8/8/2016	8/10/2016	(177)		
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Explain delay	6/6/2016	The SDT slowed development.

Project	**2015-08**
Project Name	Emergency Operations
Status	Working to Initial Posting
Comments	Planning to post for an initial comment and ballot in late July 2016.
Deliverable	EOP-004
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	Medium
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	Laura Anderson
PMOS Liaison	Ken Goldsmith
Affected Standards	EOP-004

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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							
Nominations - DT							
QR - Quality Review			1/11/2016	1/21/2016			
SP1 - SAR/PR/WP Posting 1	7/21/2015	8/19/2015	7/15/2015	8/14/2015	(6)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	***7/25/2016***	***9/8/2016***	4/18/2016	6/2/2016	(98)		
CAB - Com/Add Ballot 2	9/26/2016	11/10/2016	6/27/2016	8/11/2016	(91)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	12/1/2016	12/11/2016	8/22/2016	9/1/2016	(101)		
PTB - Present to BOT	2/1/2017	2/3/2017	10/31/2016	11/2/2016	(93)		
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Explain delay in project	5/1/2016	The delay was to reduce industry burden by simplifying the event reporting process such that a single form and submission system satisfies both EOP-004 and the U.S. Department of Energy's reporting requirements, the Project 2015-08 EOP SDT is collaborating with the U.S. Department of Energy to harmonize reporting requirements/reports. This collaboration has changed the project schedule for EOP-004. The project's PMOS representative, Ken Goldsmith, supports this project timeline change.

Project	**2015-09**
Project Name	Establish and Communicate System Operating Limits
Status	Working to Initial Ballot
Comments	We are planning on posting for a 30-day informal comment period sometime in July. As of now, we are looking at July 8 (Fri) – August 8 (Mon). The plan is to obtain initial industry feedback through the informal comment period, and then (hopefully) have our draft standard ready in time to go to the September 14 Standards Committee meeting to request authorization for our initial 45 day formal comment and ballot period, which would occur September 15 (Th) – October 31 (Mon). All of this is still tentative, but I will know more after the meeting the week of June 20, 2016.
Deliverable	FAC-010-3, FAC-011-3, and FAC-014-2
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	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	Lacey Ourso
PMOS Liaison	Andrew Gallo
Affected Standards	FAC-010-3, FAC-011-3, and FAC-014-2

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
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	***7/8/2016***	***8/7/2016***	***7/8/2016***	***8/7/2016***			

CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/15/2016	10/30/2016	4/18/2016	6/2/2016	(150)		
CAB - Com/Add Ballot 2	12/15/2016	1/29/2017	7/18/2016	9/1/2016	(150)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	3/1/2017	3/11/2017	1/2/2017	1/12/2017	(58)		
PTB - Present to BOT	5/1/2017	5/3/2017	2/1/2017	2/3/2017	(89)		
Filing - Filing with Regulators							
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.

Project	**2015-10**
Project Name	Single Points of Failure TPL-001
Status	Nominations
Comments	Revisions made to the SAR at the March 21-23, 2016 SAR ST meeting. Revisions are adding two outstanding FERC Directives from Order 786 (p. 40 and 89). Additionally, the retired MOD standards stated in TPL-001-4 Requirement R1 will be updated with the current MOD standard. The SAR is currently out for a 30-day informal comment period (May 26-June 24). A projected schedule has not been set by the SDT.
Deliverable	TPL-001
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	High
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Jordan Mallory / Al McMeekin
PMOS Liaison	Mark Pratt
Affected Standards	TPL-001

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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	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							
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
Expansion of Scope	6/14/2016	FERC directives added additional scoping in addition to industry comments following the second SAR posting. The MOD references are being updated due to some retiring in July 2016.

Project	**2015-INT-01**
Project Name	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)
Status	Working to Initial Ballot
Comments	SC approved RFI and for a project team to be formed in April 2016. The CIP SDT under Project 2016-02 is addressing this RFI.
Deliverable	Interpretation CIP-002-5.1
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Stephen Crutchfield
PMOS Liaison	Brian Murphy
Affected Standards	CIP-002-5.1

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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							
Nominations - DT			4/15/2016	4/29/2016			
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)	*7/25/2016*	*9/8/2016*	7/25/2016	9/8/2016			
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							

CAB - Com/Add Ballot 5							
FB - Final Ballot	10/4/2016	10/14/2016	10/4/2016	10/14/2016			
PTB - Present to BOT	11/15/2016	11/17/2016	11/15/2016	11/17/2016			
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Transfer RFI to the CIP SDT and update the SC	6/14/2016	Schedule updated to CIP SDT timeline.
Add CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison.

Project	**2016-01**
Project Name	Modifications to TOP and IRO Standards
Status	Posted
Comments	NOPR issued June 18, 2015 (under previous project 2014-03). Final Rule issued November 19, 2015 with three directives with an associated 18 month regulatory filing deadline. The SC authorized posting at the June 2016 SC meeting.
Deliverable	TOP/IRO Standards
Deadline	FERC deadline of May 19, 2017.
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mark Olson
PMOS Liaison	Rod Kinard
Affected Standards	TOP/IRO Standards

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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							
Nominations - DT	1/22/2016	2/4/2016	4/18/2016	5/2/2016	87		
QR - Quality Review			6/27/2016	7/7/2016			
SP1 - SAR/PR/WP Posting 1	1/22/2016	2/22/2016	3/7/2016	4/6/2016	45		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	***6/20/2016***	***8/3/2016***	7/11/2016	8/25/2016	21		
CAB - Com/Add Ballot 2	10/24/2016	12/8/2016	10/24/2016	12/8/2016			
CAB - Com/Add Ballot 3							

CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/17/2017	1/27/2017	1/17/2017	1/27/2017			
PTB - Present to BOT	2/7/2017	2/9/2017	2/7/2017	2/9/2017			
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Posted
Comments	Currently in initial comment and ballot.
Deliverable	LERC Definition
Deadline	Directive: March 30, 2017 (LERC only)
Priority in 2016-2018 RSDP, if applicable (see Note 1)	High
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	Stephen Crutchfield / Al McMeekin
PMOS Liaison	Brian Murphy
Affected Standards	CIP Standards

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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							
Nominations - DT	3/10/2016	3/24/2016	3/10/2016	3/24/2016			
QR - Quality Review	6/29/2016	7/9/2016	6/29/2016	7/9/2016			
SP1 - SAR/PR/WP Posting 1	3/23/2016	4/22/2016	3/23/2016	4/22/2016			
SP2 - SAR/PR/WP Posting 2	6/1/2016	6/30/2016	6/1/2016	7/1/2016		Expanded Scope	
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	***7/21/2016***	***9/6/2016***	9/12/2016	10/27/2016	53		
CAB - Com/Add Ballot 2	10/17/2016	12/1/2016	10/17/2016	12/1/2016			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	1/5/2017	1/15/2017	1/5/2017	1/15/2017			
PTB - Present to BOT							
Filing - Filing with Regulators			3/28/2017	3/30/2017			
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. Second SAR posting was required due to expansion of scope.

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	SAR
Comments	Draft rationale/purpose statements, consider requirement structures, Draft requirement language, Take a close look at Measures; To QR - Oct 20; SC Mtg - Nov 17 (Nov 3 SC agenda); (will require scheduling an off-cycle meeting)
Deliverable	Directives, Control Center Comm Nets (CIP-006), TD at Lows (CIP-010 or CIP-003)
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	High
P81 Req (2013)	N/A
Number of Directives	3
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Steve Crutchfield / Al McMeekin
PMOS Liaison	Brian Murphy
Affected Standards	CIP Standards

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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							
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							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	12/1/2016	1/15/2017	12/1/2016	1/15/2017			
CAB - Com/Add Ballot 2	3/31/2017	5/15/2017	3/31/2017	5/15/2017			
CAB - Com/Add Ballot 3	8/15/2017	9/29/2017	8/15/2017	9/29/2017			

CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/17/2017	10/27/2017	10/17/2017	10/27/2017			
PTB - Present to BOT	11/7/2017	11/9/2017	11/7/2017	11/9/2017			
Filing - Filing with Regulators							
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

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	SAR
Comments	Draft rationale/purpose statements, consider requirement structures, Draft requirement language, Take a close look at Measures; To QR - Oct 20; SC Mtg - Nov 17 (Nov 3 SC agenda); (will require scheduling an off-cycle meeting)
Deliverable	V5TAG, CA and BCA Definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), TO Control Centers, Virtualization
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	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	Steve Crutchfield / Al McMeekin
PMOS	Brian Murphy
Affected Standards	CIP Standards

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
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							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	12/1/2016	1/15/2017	12/1/2016	1/15/2017			
CAB - Com/Add Ballot 2	3/31/2017	5/15/2017	3/31/2017	5/15/2017			

CAB - Com/Add Ballot 3	8/15/2017	9/29/2017	8/15/2017	9/29/2017			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/17/2017	10/27/2017	10/17/2017	10/27/2017			
PTB - Present to BOT	11/7/2017	11/9/2017	11/7/2017	11/9/2017			
Filing - Filing with Regulators							
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.

Project	**2016-EPR-01**
Project Name	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards
Status	Standing Review Team
Comments	Project is on hold until the SC Standing Review Team completes their grading and 30 day posting. Project expected to kick-off in September 2016.
Deliverable	PER Stds.
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Darrel Richardson
PMOS Liaison	Mike Brytowski
Affected Standards	PER Stds.

Home

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

CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes

Project	**2016-EPR-02**
Project Name	Enhanced Periodic Review of Voltage and Reactive Standards
Status	Standing Review Team
Comments	Project is on hold until the SC Standing Review Team completes their grading and 30 day posting. Project expected to kick-off in September 2016.
Deliverable	VAR-001-4.1 & VAR-002-4
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Scott Barfield-McGinnis
PMOS Liaison	Amy Casuscelli
Affected Standards	VAR-001-4.1 & VAR-002-4

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
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

No.
Note 1
Note 2
Note 3
Note 4
Note 5
Note 6
Note 7
Note 8
Note 9
Note 10

Description
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.
Refers to guidances from regulatory orders for standards activity to consider, but that do not carry the same effect as a directive.
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.
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).
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.

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Projected Posting Schedule

Below is a schedule of upcoming postings so you have the opportunity to schedule time with appropriate subject matter experts in your organizations to review these standards and ensure that balloters will be available during the ballot windows or have assigned proxies. The projected schedule is subject to change. For a high-level view of the planned schedule for all active projects, including information regarding the number of paragraph 81 requirements, directives, and guidances, please see the Project Tracking Spreadsheet on the Standards page.

Week of July 25: *(*Pending SC Authorization July 20)*

- 45-day comment and initial ballot
  - Project 2015-08 Emergency Operations (EOP-004)*
  - Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)*

Week of August 1: None

Week of August 8: None

Week of August 15: None

Week of August 22: None

Week of August 29: None

**Please note that the dates in the chart below are estimates and are subject to change.

Projects	7/25	8/1	8/8	8/15	8/22	8/29	Closing Date
Cost Effectiveness Pilot							
EPR Standing Review Team Grading		8/1					
Functional Model							9/7
2015-08 Emergency Operations EOP-004	7/25						9/8
2015-08 Emergency Operations EOP-005				8/15			
2015-08 Emergency Operations EOP-006				8/15			
2015-08 Emergency Operations EOP-008				8/15			
2015-09 System Operating Limits FAC-010							
2015-09 System Operating Limits FAC-011			8/12				
2015-09 System Operating Limits FAC-014			8/12				
2015-10 Single Points of Failure TPL-001		8/5					
2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security	7/27						9/12
2015-INT-03 Interpretation of TOP-002-2.1b for FMPP							
2016-01 Modifications to TOP and IRO Standards		8/3					
2016-02 Modifications to CIP Standards							9/6
2016-EPR-01 – Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards PER-001, PER-003 and PER-004							
2016-EPR-02 – Enhanced Periodic Review of Voltage and Reactive Standards VAR-001 and VAR-002							
2017-2019 RSDP							

	Informal comment period
	Nomination solicitation
	30-day comment period
	45-day comment period and ballot/additional ballot
	Final ballot

RSC Meeting #16-4, Agenda Item 4.0 Open Action Items

Item	Description	Owner	Due	Status
4.1	Guy Zito will follow up with CCC on CIP-014 auditor practice guide and status of SAR.	Guy Zito	RSC Meeting	Ongoing
4.2	Si Truc Phan provide updates to the group on the status of GMD (Hydro Quebec Parameters)	Si Truc Phan	RSC Meeting	Ongoing

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Weekly Standards & Compliance Bulletin

August 1–7, 2016

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2016-01 – Modifications to TOP and IRO Standards | IRO-002-5 and TOP-001-4	Initial Ballots and Non-binding Polls	07/25/16	08/03/16
Project 2015-08 – Emergency Operations | EOP-005-3, EOP-006-3 and EOP-008-2	Initial Ballots and Non-binding Polls	08/04/16	08/15/16
Project 2016-02 – Modifications to CIP Standards | CIP-003-7, Implementation Plan, and Definition of LERC	Initial Ballots and Non-binding Polls	08/26/16	09/06/16
NEW Project 2015-08 – Emergency Operations | EOP-004-4	Initial Ballots and Non-binding Polls	08/30/16	09/08/16
NEW Project 2015-INT-01 – Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec) | CIP-002-5.1	Initial Ballot	09/02/16	09/12/16
Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2015-08 – Emergency Operations | EOP-005-3, EOP-006-3 and EOP-008-2	Join Ballot Pools	06/29/16	07/28/16
Project 2016-02 – Modifications to CIP Standards | CIP-003-7, Implementation Plan, and Definition of LERC	Join Ballot Pools	07/21/16	08/19/16
NEW Project 2015-08 – Emergency Operations | EOP-004-4	Join Ballot Pools	07/25/16	08/23/16
NEW Project 2015-INT-01 – Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec) | CIP-002-5.1	Join Ballot Pools	07/27/16	08/25/16

Posted for Comment (comment periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Enhanced Periodic Review | Standards Grading	Comment Form	06/30/16	08/01/16
Project 2016-01 – Modifications to TOP and IRO Standards | IRO-002-5 and TOP-001-4 Draft RSAWs are posted through August 3, 2016. Submit comments to RSAWfeedback@nerc.net.	Comment Form	06/20/16	08/03/16
Project 2015-09 – Establish and Communicate System Operating Limits	Comment Form	07/14/16	08/12/16
Project 2015-08 – Emergency Operations | EOP-005-3, EOP-006-3 and EOP-008-2 Draft RSAWs are posted through August 15, 2016. Submit comments to RSAWfeedback@nerc.net.	Comment Form	06/30/16	08/15/16
Project 2016-02 – Modifications to CIP Standards | CIP-003-7, Implementation Plan, and Definition of LERC	Comment Form	07/21/16	09/06/16
NEW Project 2015-08 – Emergency Operations | EOP-004-4	Comment Form	07/25/16	09/08/16
NEW Project 2015-INT-01 – Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec) | CIP-002-5.1	Comment Form	07/27/16	09/12/16

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
Request for Comments on Power Plant Model Verification Using PMU Draft Reliability Guideline: The NERC Planning Committee's Synchronized Measurement Subcommittee (SMS) developed the draft Reliability Guideline: Power Plant Model Verification Using	Submit comments to reliabilityguidelinecomments@nerc.net.	06/20/16	08/05/16

PMUs. This Reliability Guideline provides a strategy for using PMU data and disturbance-based verification tools as one available method for performing power plant model verification. It is meant to provide entities with PMUs monitoring power plant or generating unit output with appropriate technical material to effectively pursue model verification using disturbance data from PMUs. The NERC Planning Committee reviewed the draft of the guideline at its June 2016 meeting and approved it for a 45-day industry comment period.			
Request for Comments on Reactive Power Planning and Operations Draft Reliability Guideline: The NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS) developed the draft Reliability Guideline: Reactive Power Planning and Operations. This Reliability Guideline provides strategies and recommended practices for reactive power planning and voltage control. It is meant to provide utilities with guidance and direction related to the modeling, study, and placement of reactive power resources in support of robust voltage profiles. The strategies set forth in this Reliability Guideline center around the need for static and dynamic reactive power resource planning and operational planning, as outlined in relevant NERC Reliability Standards. In addition, this Reliability Guideline aligns with the NERC's mission of improved reliability through sharing industry practices for planning and operating the bulk power system.	Submit comments to reliabilityguidelinecomments@nerc.net.	06/20/16	08/05/16

The NERC Planning Committee reviewed the draft of the guideline at its June 2016 meeting and approved it for a 45-day industry comment period.			
Florida Reliability Coordinating Council Regional Reliability Standard Development Process Manual Posted for Comment: NERC is posting the proposed Florida Reliability Coordinating Council's Regional Reliability Standard Development Process Manual for a 45-day procedural comment period. Regional standards development procedures define a regional entity's process for development, revision, reaffirmation, and withdrawal of a Regional Reliability Standard. An unofficial Word version of the comment form is posted on the Regional Reliability Standards Under Development Page.	Submit comments using the electronic form.	07/01/16	08/15/16
Comment Period Open for PRC-006-3 – Automatic Underfrequency Load Shedding, NPCC Quebec Regional Variance Revision: A 45-day comment period for PRC-006-03 is open through August 22, 2016. This proposed revision to the NPCC Regional Variance specifically applies to the Quebec Region only. Due to the unique nature of the Quebec province being its own interconnection, the variance is being developed using the NPCC Regional Standard Processes Manual. Specifically, the "Section D. Regional Variance" and "Attachment 1A" are proposed to be revised.	Submit comments electronically through the NPCC website.	07/07/16	08/22/16
Request for Comments on Time Monitoring Reference Document: NERC Operating Committee's Resources Subcommittee developed the Time Monitoring Reference Document, which specifies how manual Time Error Corrections (MTEC) are to be implemented if needed to resolve issues and outlines procedural responsibilities assigned to the time monitor.	Submit comments via email using the Time Monitoring Reference Document Comment Form.	07/21/16	09/05/16

Based on the changes made in Reliability Standard BAL-001-2 regarding the calculation of BAAL, the Scheduled Offset methodology referenced in Attachment A of the Reference Document may lead to errors in the calculation of frequency support during MTEC. Therefore, in submitting comments regarding the draft Reference Document please respond to the following: • Do industry participants continue to use the Schedule Offset methodology? • If so, should this be allowed despite BAL-001-2 effectiveness or should the Schedule Offset methodology be removed as an option for MTEC? The NERC Operating Committee reviewed the initial draft of the document at its June 2016 meeting and approved it for additional comment by June 30, 2016. Subsequently, it was approved for a 45-day industry comment period.			
Comment Period Open for Functional Model Advisory Group Document: A 45-day informal comment period on the proposed revisions to the Reliability Functional Model (FM) and Reliability Functional Model Technical Document (FMTD), is open through September 7, 2016. The Functional Model Advisory Group will review all responses received during the comment period and determine the next steps of the project.	Submit comments using the electronic form	07/22/16	09/07/16
NEW **Request for Comments on Proposed Changes to NERC Rules of Procedure:** The current NERC Rules of Procedure contemplate that hearings to resolve contested noncompliance, mitigation plans, remedial action directives, penalties, or sanctions may be held at each Regional Entity (RE). NERC is proposing the introduction of a Consolidated Hearing Process, which would allow REs the *option* to	Submit comments electronically to ROPcomments@nerc.net.	07/26/16	09/09/16

move the hearing process to NERC. The proposed revisions are designed to streamline costs, enhance consistency, and increase efficiencies. As noted in the detailed summary of proposed changes, the composition of the consolidated Hearing Body, which would include members appointed by the RE, would ensure that a regional perspective is maintained. Redlined versions of NERC Rules of Procedure, Appendix 2, and Appendix 4C showing the proposed revisions are now available on the NERC Rules of Procedure web page. NERC intends to submit these changes to the NERC Board of Trustees for consideration at its November 2016 meeting.			

GENERAL STANDARDS NEWS

NEW Resources Posted
NERC has posted the streaming webinar and slide presentation for the July 22, 2016 Project 2016-01 – Modifications to TOP and IRO Standards webinar.

NEW Nomination Period Open for Project 2016-03 Standard Drafting Team
Nominations are being sought for members of the Project 2016-03 Standards Authorization Request and standard drafting team (SDT) through August 18, 2016.

QUICK LINKS
Register in the SBS
Original Balloting Software
Projected Standards Posting Schedule
Project Tracking Spreadsheet
Standards Related Questions – Single Portal
2016–2018 Reliability Standards Development Plan

On July 21, 2016, FERC issued Order No. 829, directing NERC to develop a new or modified Reliability Standard that addresses supply chain risk management for industrial control system hardware, software, and computing and networking services associated with Bulk Electric System (BES) operation. FERC also directed the new or revised Standard to be filed within one year of the effective date of the Order. Potential SDT members for Project 2016-03 – Cyber Security Supply Chain Management should have significant management experience or subject matter expertise with the global supply system related to communications and control hardware, software, and services affecting BES operations and BES Cyber Systems. Expertise with developing and implementing controls, including policies, practices, guidelines, and

standards designed to mitigate the introduction of cybersecurity risks in the supply chain is needed, with emphasis on experience in the four objectives outlined above. Also, there is a need for a team members with an understanding of the CIP Reliability Standards as discussed in Order No. 829 as well as procurement practices for BES Cyber Assets, with a focus on cyber security. In addition, compliance, legal, regulatory, facilitation, and technical writing skills are desired. Previous drafting team experience or other experience with development of standards is beneficial, but not required.

A significant time commitment is expected of SDT members to meet the one-year regulatory deadline established in Order No. 829. SDT activities include participation in technical conferences, stakeholder communications and outreach events, periodic drafting team meetings and conference calls. Approximately two in-person meetings per quarter can be expected (on average three full working days each meeting), as well as periodic conference calls as needed.

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 Standard Drafting Team Vacancies page and the project page. NERC staff will present nominations to the Standards Committee in September 2016. Nominees will be notified shortly after the appointments have been made.

Nomination Period Open for Project 2015-10 Standard Drafting Team

Nominations are being sought for Project 2015-10 – Single Points of Failure TPL-001 standard drafting team (SDT) members through August 5, 2016.

The time commitment for this project is expected to be up to two face-to-face meetings per quarter (on average three full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the SDT sets forth. Drafting teams may have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the SDT effort is outreach. Members of the team are expected to conduct outreach during development, prior to posting to ensure all issues can be addressed. Previous drafting team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included on the project page and the nomination form.

Use the electronic form to submit a nomination. 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 SDT meetings if appointed by the Standards Committee (SC). If appointed, you are expected to attend most of the face-to-face meetings as well as participate in the meetings held via conference calls. The SC is expected to appoint members to the team in September 2016. Nominees will be notified shortly after the appointments have been made.

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

NEW CIP V5 Transition Program Resources Updated

NERC has updated both the CIP V5 Transition Program Workshops document and the Curriculum document with additional NERC and Regional Entity events and links to resources from past events. These documents are located in the CIP Workshops and Curriculum section of the CIP V5 Transition Program web page.

NEW Newly Enforceable Standards

On August 5, 2016, Requirement 2.1 of CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments will become enforceable.

QUICK LINKS

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

OTHER NEWS

NEW NERC News Posted

NERC's monthly newsletter – NERC News – has been posted for July. Highlights in this edition include:

- 10-Year Anniversary of ERO
- NERC Signs Agreement with EU Energy Directorate
- Updated Key Players Page Reflects NERC's International Mission
- NERC Publishes New Lessons Learned
- Upcoming Events

STANDARDS SUBJECT TO FUTURE ENFORCEMENT

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

U.S. Enforcement Date	Standard(s)
August 5, 2016 ENFORCEABLE THIS WEEK	CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirement 2.1)
October 1, 2016	CIP-004-6 – Cyber Security – Personnel & Training (Requirement 4.2)
	FAC-003-4 – Transmission Vegetation Management
	MOD-031-2 – Demand and Energy Data
January 1, 2017	IRO-010-2 - Reliability Coordinator Data Specification and Collection (Requirements R1 and R2);
	TOP-003-3 – Operational Reliability Data (all Requirements except R5)
April 1, 2017	CIP-003-6 – Cyber Security – Security Management Controls (Requirements 1.2–2) CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirement 4)
	EOP-004-3 – Event Reporting; EOP-010-1 – Geomagnetic Disturbance Operations (Requirement 2); EOP-011-1 – Emergency Operations;
	FAC-010-3 – System Operating Limits Methodology for the Planning Horizon; FAC-011-3 – System Operating Limits Methodology for the Operations Horizon;
	IRO-001-4 – Reliability Coordination: Responsibilities; IRO-002-4 – Reliability Coordination: Monitoring and Analysis; IRO-008-2 – Reliability Coordinator Operational Analyses and Real-time Assessments; IRO-010-2 – Reliability Coordinator Data Specification and Collection (Requirement R3); IRO-014-3 – Coordination Among Reliability Coordinators; IRO-017-1 – Outage Coordination;
	MOD-029-2a – Rated System Path Methodology; MOD-030-3 – Flowgate Methodology;

	PRC-010-1 – Undervoltage Load Shedding; PRC-004-WECC-2 – Protection System and Remedial Action Scheme Misoperation; PRC-015-1 – Remedial Action Scheme Data and Documentation; PRC-016-1 – Remedial Action Scheme Misoperations; PRC-017-1 – Remedial Action Scheme Maintenance and Testing; PRC-023-4 – Transmission Relay Loadability
	TOP-001-3 – Transmission Operations; TOP-002-4 – Operations Planning; TOP-003-3 – Operational Reliability Data (Requirement R5);
April 2, 2017	PRC-004-5(i) – Protection System Misoperation Identification and Correction; PRC-010-2 – Undervoltage Load Shedding;
July 1, 2017	CIP-004-6 – Cyber Security – Personnel & Training (Requirements 2.3, 4.3, 4.4) CIP-006-6 – Cyber Security — Physical Security of BES Cyber Systems (Requirement 3.1) CIP-008-5 – Cyber Security — Incident Reporting and Response Planning (Requirement 2.1) CIP-009-6 – Cyber Security — Recovery Plans for BES Cyber Systems (Requirement 2.1–2.2) CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirement 3.1)
	MOD-033-1 – Steady-State and Dynamic System Model Validation
January 1, 2018	PRC-026-1 – Relay Performance During Stable Power Swings (Requirement 1)
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 R2, 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 R2, 2.1–2.1.5)
January 1, 2020	PRC-026-1 – Relay Performance During Stable Power Swings (Requirements 2–4)

BOARD OF TRUSTEES AND FERC ACTION

NEW NERC Filings

On July 25, 2016, NERC filed with FERC comments in response to the notice of proposed rulemaking for proposed Reliability Standard BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event.

NERC's 2016 filings to FERC are available here.

NEW NERC Board of Trustees Meeting Agenda Packages and Schedule of Events Posted

Agenda packages for the Board of Trustees, Compliance Committee, Corporate Governance and Human Resources Committee, Member Representatives Committee, and Standards Oversight and Technology Committee meetings on August 10–11, 20116 in Halifax, Nova Scotia are now available. The agenda package for the Finance and Audit Committee will be posted by August 4. A schedule of events is also available.

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

- Distributed Energy Resources Workshop – August 2–3, 2016, Atlanta | Meeting Registration | Hotel Registration | NEW Final Agenda
- Power Plant Model Verification and Testing Workshop – September 20–21, 2016, Atlanta | Details | Register | Agenda
- Monitoring and Situational Awareness Technical Conference – September 27–28, 2016, Folsom, CA | Register | Hotel and Travel Details | Previous Conference Presentations

Webinars

- NEW Project 2015-09 – System Operating Limits Webinar – 3:00–4:30 p.m. Eastern, August 3, 2016 | Register
- NEW Project 2016-02 – Modifications to CIP Standards Webinar 12:30–2:00 p.m. Eastern, August 16, 2016 | Register

Standing Committee Meetings and Conference Calls

- Board of Trustees, Members Representatives Committee, and Board Committees Meetings – August 10–11, 2016 | Halifax, Nova Scotia | Details and Registration
- Standards Committee Meeting – 8:00 a.m.–2:00 p.m. Pacific, September 14, 2016 | Register
- Critical Infrastructure Protection Committee Meeting – September 20–21, 2016 | Albuquerque, NM |Register | Register for hotel (hotel cutoff date: August 29, 2016)

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 2015-08 – Emergency Operations – August 16–18, Milwaukee, WI | Register | Agenda
- Project 2016-01 – Modifications to TOP and IRO Standards – August 16–18, St. Paul, MN | Register
- Project 2015-09 – System Operating Limits – August 23–25, Folsom, CA | 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.

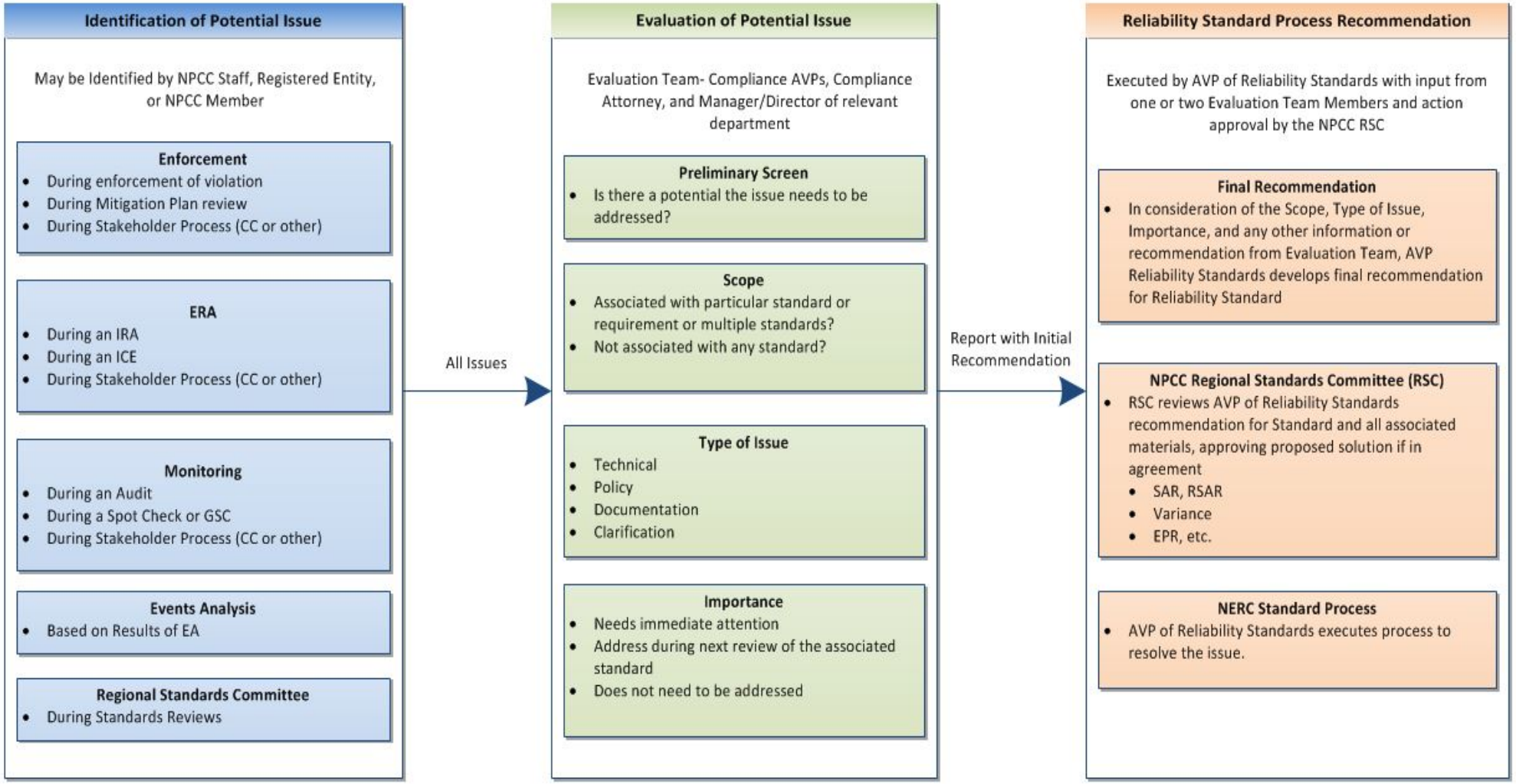
If you would like to receive this bulletin or be added to the distribution list for a particular standards project, please email sarcomm@nerc.net. For more information about any of the compliance news listed in the bulletin, please contact Linda Jenkins.

NPCC Feedback Mechanism

Presentation for 8/10/2016 Reliability Standards Committee Meeting

NPCC, Inc.

NPCC Regional Feedback Mechanism to Improve Reliability Standards



Issue Identification

- Four main areas:
  - Entity Risk Assessment, Monitoring, Enforcement, Events Analysis
- Identification by:
  - NPCC, Registered Entity, NPCC Member

NPCC, Inc.

Issue Evaluation

- Intended to identify the scope, type, and importance of the Issue
- Intended to identify the appropriate means within the existing NERC Standards Development Process to further examine the Issue
- Not intended to replicate or replace the existing means to change the Reliability Standard

NPCC, Inc.

Evaluation Team

- Two Compliance AVPs, Compliance Attorney, and potentially others;
- Evaluation Team notifies Compliance Committee of Issue to be evaluated.
- Additional people may be added and may include registered entity, NPCC member, other NPCC staff

NPCC, Inc.

Evaluation - Preliminary Screen

- Designed to eliminate non-issues
- Two weeks to perform
- Issue already addressed or other reason not to evaluate
- Preliminary Screen failures are documented and provided to CC, RSC, and requester

NPCC, Inc.

Evaluation

- Scope of Issue
  - Specific requirement, specific Standard, multiple Standards, etc.
- Type of Issue
  - Not prescriptive
  - Non-exhaustive list of factors
  - Technical, policy, documentation, duplication, etc.
- Importance of Issue
  - To help identify correct NERC Standards Development Process
- Other Input (not necessary)
  - Proposed Changes

NPCC, Inc.

Evaluation of Issues Report

- Within some timeframe (45 days)
- Must include: Evaluation Team members, Scope, Type, Importance
- May include: Other Input, Recommendation of NERC Process
- The Evaluation Team is expected to reach a consensus but,
  - AVP has final determination
  - Minority position included of non-consensus items
- Provided to CC, RSC, AVP of Reliability Standards, requestor

NPCC, Inc.

Reliability Standard Development Process

- Determined by AVP of Reliability Standards and RSC
- Uses Evaluation of Issue Report
- Evaluation of Issue Report may be shared with NERC process
- Potential NERC Processes
  - Add to RSDP
  - SAR
  - Interpretation
  - Variance
  - Implementation Guidance (not a standard activity)

NPCC, Inc.

Issues Recommended for Implementation Guidance

- Issues recommended for the development of Implementation Guidance in accordance with NERC Compliance Guidance Policy will go to the Compliance Committee

NPCC, Inc.

Tracking Issues

- Feedback Loop Tracking Sheet maintained by feedback loop administrator
- Tracking number, requester, evaluation team, leader, Issue (short description)
- Dates (submission date, evaluation team notification date, preliminary screen date, evaluation of issue report date)

NPCC, Inc.

Questions

NPCC, Inc.

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Functional Model Advisory Group

Guy V. Zito

Regional Standards Committee Meeting

August 10-11, 2016

RELIABILITY | ACCOUNTABILITY






Agenda

- Background information regarding the Functional Model (FM) and Functional Model Advisory Group (FMAG)
- 2016 FMAG project
- Questions

Background Information

- **Purpose of the Functional Model (FM)**:
  - Guideline that identifies the functions that must be performed to ensure that the Bulk Power System is planned and operated in a reliable manner.
  - Describes the specific tasks that are required to perform the reliability functions, and the relationships between the functional entities that perform those tasks

- **Functional Model Technical Document (FMTD):** Companion document that elaborates on various functions, tasks and relationships between functional entities.

Functional Model Advisory Group

- **<u>Purpose of the Functional Model Advisory Group (FMAG)</u>**:
  1. Maintain the FM (and FMTD) to ensure the model correctly reflects the industry today, and
  2. Evaluate and incorporate new and emergent reliability-related tasks

- **FMAG reports to the Standards Committee (SC) and "advises and consults" with the Planning Committee (PC), Operating Committee (OC), and Critical Infrastructure Protection Committee (CIPC)**

Revisions to the FM and FMTD

- **FMAG to maintain FM to ensure it accurately reflects the industry today and incorporates any new or emergent reliability-related tasks. Review may be initiated by the Standards Committee, FMAG or based on any identified reliability-related need, such as:**
  - Standing/technical committees may identify an issue or area for consideration, and request the FMAG assess whether appropriate to add a new (or revise an existing) function, task or relationship
  - Industry request
- **Revision process:**
  - FMAG to work with standing committees (Operating Committee, Planning Committee, Critical Infrastructure Protection Committee) to obtain "endorsement" of technical content
  - Proposed revisions posted for industry comment period
  - SC ultimately endorses revisions to the FM and FMTD, before the documents are posted on the NERC website

FMAG Roster

Name	Organization
Jim Cyrulewski (co-chair)	JDRJC Associates, LLC
Jerry Rust (co-chair)	Northwest Power Pool
Dennis Chastain	Tennessee Valley Authority
Al Dicaprio	PJM Interconnection
Pete Heidrich	FRCC
Tony Jankowski	We Energies
Lorissa Jones	Bonneville Power Administration

Name	Organization
Ben Li	Ben Li Associates
Linn Oelker	LG&E and KU Services Company
Steven Rueckert	WECC
Tom Siegrist	Stone, Mattheis
Mike Steckelberg	Great River Energy
Mike Yealland	Independent Electricity System Operator (retired)
Joseph A. Wilson	Tacoma Power

2016 FMAG project

- **Version 5 (current version) of the FM and FMTD developed in 2009 and approved by the NERC Board of Trustees in 2010.**

- **Focus of 2016 FMAG project:**
  - Review the model to ensure it correctly reflects the industry today
  - Identify changes needed to the model as a result of new and emergent reliability-related issues
  - Identify changes needed as a result of recent NERC initiatives (*i.e.*, Risk-Based Registration initiative) and standard development projects (*i.e.*, Alignment of Terms)

Project Timeline

- **January 19-20**: FMAG meeting to identify areas for focus
- **March 8**: Inform standing committees (OC, PC, CIPC) of work underway, and obtain initial feedback (specific to area of expertise)
- **March 17-18**: FMAG meeting to develop revisions to the FM
- **April 13-15:** FMAG meeting to develop revisions to FM and FMTD
- **June 7-8:** Present proposed revisions to committee members (OC, PC, CIPC) for the purpose of obtaining feedback
- **June 15-17:** FMAG meeting to review and incorporate feedback from committees (OC, PC, and CIPC), and revise FM and FMTD

Project Timeline (cont)

- **July 20:** Obtain SC approval to post proposed revisions to FM and FMTD for informal industry comment period
- **July 22 – September 7:** Post proposed revisions for 45-day industry comment period
- **September/October**: FMAG meeting to review industry comments and revise FM and FMTD based on industry feedback
- **December:** Present final revisions to the FM and FMTD to standing committees (OC, PC, and CIPC) for endorsement

Overview of Proposed Revisions to the FM

- Incorporated Glossary terms
- Consolidated ERO-related functions (Reliability Assurer function)

Overview of Proposed Revisions to the FM

- Clarified planning functions: Planning Coordinator (PC), Transmission Planner (TP), and Resource Planner (RP)
  - Identified differences in the various functions and tasks performed by the functional entities, and how the planners work together to ensure the BES has adequate reliability planning
  - Both the TP and PC perform assessments to evaluate whether future transmission system performance will meet the minimum acceptable system performance requirements
  - However, TP and PC may consider different system conditions (and BES facilities) in performing their respective assessments; this flexibility allows for studying a wider range of system conditions and allows for a more complete and comprehensive assessment of the BES

Overview of Proposed Revisions to the FM

- Planning functions (cont):
  - TP assessment includes the collection of transmission assets over which the TP is responsible for planning (“TP Area”).
  - PC assessment includes the collection of transmission assets over which the PC is responsible for coordinating planning (“PC Area”). The PC Area is normally comprised of more than one TP. The PC focuses on assessments of both Transmission and resource planning for its PC Area.
  - Every BES facility must have one associated TP and at least one PC. This means that every facility in the TP Area should be included in the assessment conducted by the TP.

Overview of Proposed Revisions to the FM

- Added cyber and physical security tasks (RC, BA, TOP, TO, IC, DP, GO and GOP)
  - "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data."
  - "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."

- Added TOP task related to operations: "Operate or direct the operation of Transmission Facilities in its TOP Area."

Overview of Proposed Revisions to the FM

- Revised tasks to clearly identify what actions are required for an Interchange transaction (IC, BA, TSP, PSE, and LSE)

- Clarified TSP task of acquiring Ancillary Services
  - "Acquire Ancillary Services to support Transmission Service."

- Clarified DP task includes delivery to end-use customer or distribution-connected energy resource(s)
  - "Provide and operate electrical delivery Facilities between the Transmission system and the end-use customer or distribution-connected energy resource."

Contact information

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- Jerry Rust (co-chair)

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Summary of Revisions to Reliability Functional Model

Functional Model Advisory Group

Background Information

Background regarding the Reliability Functional Model and Reliability Functional Model Technical Document

The Reliability Functional Model (FM) is a guideline that identifies the functions that must be performed to ensure that the Bulk Power System (BPS) is planned and operated in a reliable manner. The FM describes, in general terms, the functions that must be performed to ensure reliability, the specific tasks that are necessary to perform each function, and the relationships between functional entities that perform the various tasks. In its capacity of a guideline, the FM serves to provide a framework for NERC Reliability Standards as they are developed through the standard development process. The FM is independent of any particular organizational or market structure. The focus of the FM is solely on identification of reliability-related functions and the associated tasks and relationships. The FM is **not** a "standard" and does not have compliance effects. If there is a conflict between the FM and Reliability Standards, the Reliability Standards always take precedence. Also, the FM is **not** intended to identify the entities responsible for NERC registration. The NERC registration process is undertaken by NERC (and the Regional Entities) pursuant to authority from FERC, ultimately derived from the Federal Power Act. The FM has no authority, ability, or intent to impact or influence the NERC Registration process. The Reliability Functional Model Technical Document (FMTD) is a companion document to the FM. It serves to elaborate on the manner in which the various functional entities carry out their functions and perform their tasks.

Background regarding the Functional Model Advisory Group

The purpose of the Functional Model Advisory Group (FMAG), as outlined in the FMAG Scope document, is to (1) maintain the FM and FMTD to ensure the model correctly reflects the industry today, and (2) evaluate and incorporate new and emergent reliability-related tasks. The FMAG reports to the Standards Committee (SC), and works with the Planning Committee (PC), Operating Committee (OC), and Critical Infrastructure Protection Committee (CIPC) to obtain consensus regarding any proposed changes to the FM and FMTD. All proposed changes to the FM must be posted for industry comment, obtain consensus agreement from the PC, OC, and CIPC, and, ultimately, approval by the SC.

Overview of the 2016 FMAG project

In December 2015, the FMAG began a comprehensive review and assessment of the FM and FMTD to determine if it correctly reflects the industry today and whether there was a need to incorporate any new or emerging reliability-related tasks. As a result of the review, the FMAG identified many areas in need of revision. Below is a general summary of the type and nature of the revisions proposed by the FMAG.

General Overview of Proposed Revisions

1. Incorporated defined terms from the NERC Glossary of Terms: A large majority of the proposed revisions relate to incorporation of definitions from the NERC Glossary of Terms. For each proposed revision, the FMAG undertook a review to determine whether it was appropriate to incorporate the defined term, given the context and usage of the term in the FM. In some instances, the Glossary term was not used because the FMAG did not believe it had the intended meaning of the defined term, as used in the FM. In some instances, the term was simply capitalized to indicate it had the meaning of the Glossary term. In other instances, the word or phrase was replaced with a defined term (*i.e.*, reliability-related services replaced with Interconnected Operations Service).

2. Consolidated ERO-related functions: In the current version of the FM (version 5), there are separate functions for Standards Developer, Compliance Enforcement Authority and Reliability Assurance. The FMAG believes that all of these fall under one "function" of ensuring the reliability of the BPS. Therefore, all functions related to reliability assurance were moved to the Reliability Assurance function. The Reliability Assurance function is intended to include any tasks performed by the Electric Reliability Organization (ERO) to ensure the reliability of the BPS, including, for example, development of Reliability Standards, development and implementation of a compliance and enforcement program, and development and maintenance of a program for identifying and registering entities responsible for compliance.

3. Clarified the planning functions: Planning Coordinator (PC), Transmission Planner (TP), and Resource Planner (RP): The proposed revisions seek to identify the differences in the various planning functions, the tasks performed by the functional entities, and how the planners work together to ensure the Bulk Electric System (BES) has adequate reliability planning.

4. Clarified how Interchange occurs: The proposed revisions provide clarity regarding how the various functions and functional entities work together to perform Interchange, including incorporation of appropriate Glossary terms (*i.e.*, Requests for Interchange, Arranged Interchange, Confirmed Interchange).

5. Added cyber and physical security tasks: The FMAG is proposing to add two new tasks related to security protections for cyber assets and physical assets, and communication regarding an actual or suspected threat to those assets. The new tasks have been added to the following functions:

- Reliability Coordinator (RC)
- Balancing Authority (BA)
- Transmission Operator (TOP)
- Transmission Owner (TO)
- Interchange Coordinator (IC)
- Distribution Provider (DP)
- Generator Owner (GO)
- Generator Operator (GOP).

45-day informal comment period

The proposed revisions to the FM and FMTD are posted for a 45-day informal comment period. The FMAG will review all comments submitted and incorporate, as appropriate, proposed revisions to the FM and FMTD. In the documents posted for comment, the highlighted language is intended to indicate that the revision relates to a substantive change. The FMAG requests that you focus your comments on these highlighted revisions. Revisions that are not deemed substantive include revisions related to:

- Incorporation of a Glossary term;
- Clarification to the existing language (*i.e.*, use of consistent terminology);
- Changes to the order or manner of presentation of information (*i.e.*, rearrangement of tasks to follow a chronological order of how the tasks are performed);
- Consolidation of related items or removal of redundancies; and
- Changes to reflect how Interchange works, including incorporation of NERC Glossary terms.

Below is a mapping of the proposed revisions, along with an explanation of why the revision was needed necessary.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
1	General (Executive Summary, Introduction, Purpose, etc.)	Consolidated general background information and into one section (Section I – Purpose of the FM).	Provided clear, concise summary of the purpose of the FM; also, explained that the FM is a guideline and not a standard, nor does it identify entities for NERC Registration.
2	Standards Developer	Deleted entire section	See “Reliability Assurer” section

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
3	Compliance Enforcement Authority	Deleted entire section	See "Reliability Assurer" section
4	Reliability Assurer	Revised section to include greater detail regarding the tasks performed by the ERO (and the Regional Entities).	Identified the various tasks performed by NERC (and the Regional Entities) in its role as the ERO.
5	Planning Coordinator	Revised entire section to provide clarity regarding the differences in roles and tasks performed by the planning entities (*i.e.*, Planning Authority, TP, and RP). Also, provided greater clarity regarding how the planners work together to ensure the BES has adequate reliability planning.	New Tasks 1, 2, 3 work together to outline the sequential process followed by the PC to conduct transmission system assessments. The component of "analysis and development of resource adequacy plans" was intentionally removed from the PC tasks. With regard to the assessments performed: • Both the TP and PC perform assessments to evaluate whether future transmission system performance will meet the minimum acceptable system performance requirements. However, the TP and PC may consider different system conditions (and BES facilities) in performing their respective assessments; this flexibility allows for studying a wider range of system conditions and allows for a more complete and comprehensive assessment of the BES. • TP assessment includes the collection of transmission assets over which the TP is responsible for planning ("TP Area"). • PC assessment includes the collection of transmission assets over which the PC is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one TP. The PC focuses on assessments of both Transmission and resource planning for its PC Area. • Every BES facility must have one associated TP and at least one PC. This means that every facility in the TP Area

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
			should be included in the assessment conducted by the TP.
6	Transmission Planner	Deleted Task No. 7: ~~Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.~~	The nature of the TP's work requires that the TP has an understanding of the "typical" system protection and control schemes utilized by the associated Transmission Owner(s). Through interaction with the TO, the TP can also have an influence on the system protection scheme standards that a TO uses. In some instances, the TP may recommend a Remedial Action Scheme (RAS) as a means of addressing Transmission system performance issues. The TP's awareness of, and influence on, system protection schemes were viewed as an integral part of the TPs' modeling and assessment tasks. The FMAG determined that a discussion of the TP's involvement with protection systems was better suited to the FMTD. Therefore the task was deleted.
7	Transmission Planner	Revised Relationship No. 9: Deleted "Resource Planner" and added "Planning Coordinator" "Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Transmission Planner area with other Transmission Planners and the Planning Coordinator~~Resource Planners~~, as appropriate."	Removed "Resource Planner" and added "Planning Coordinator" because the PC is also concerned with transmission system assessments, whereas the RP is not.
8	Transmission Planner	Revised Relationship No. 10: Added "Planning Coordinator"	Added "Planning Coordinator" because of the PCs role and interest in assessing transfer capability.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		"Coordinates and develops transfer capability values with other Transmission Planners, Reliability Coordinators, Transmission Operators, Transmission Owners ~~and~~ Transmission Service Providers, and the Planning Coordinator."	
9	Resource Planner	Revised entire section to provide clarity and to distinguish resource planning tasks from other planning functions. Also, provided greater clarity regarding how the RPs interact with the TPs and Transmission Service Providers to ensure the BES has adequate resource planning.	Removed the prescriptive language to emphasize the completion of the task versus "how to perform" the task. Also, revised the language to improve clarity of the functional relationships.
10	Reliability Coordinator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 11: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 12: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 11: Additional task necessary to identify RC reliability related responsibilities associated with cyber and physical security. New Task No. 12: Additional task necessary to identify RC communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
11	Reliability Coordinator	Revised Relationship No. 2: Added Distribution Providers	Added DP because the RC receives reliability-related facility and operational data from the DP.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		"Receives facility and operational data from Generator Operators, Distribution Providers, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators."	
12	Reliability Coordinator	Revised Relationship No. 6: "Develop~~s~~ Interconnection Reliability Operating Limits, and provide them to those entities with a reliability-related need~~based on Transmission Owners' and Generator Owners' specified equipment ratings, and provides them to Transmission Operators~~."	Revised the relationship to reflect fact that RC establishes IROLs based on a number of factors (not limited to the equipment ratings); and the RC communicates the IROLs to various entities (not solely the TOP) based upon the specific requirements outlined in the RC's methodology or specific procedure in place.
13	Reliability Coordinator	Deleted Relationship No. 12: Duplicative ~~"Provide IROLs and TTC to the Transmission Service Provider for ATC calculation."~~	This is covered in Relationship No. 6.
14	Balancing Authority	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 14: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 15: "Communicate to appropriate authorities and relevant functional	New Task No. 14: Additional task necessary to identify BA reliability related responsibilities associated with cyber and physical security. New Task No. 15: Additional task necessary to identify BA communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		entities of an actual or suspected attack on cyber assets and/or physical assets."	
15	Balancing Authority	Added new Relationship: New Relationship No. 1: "Ahead of Time: Receive generator Facility plans from Generator Operators within the Balancing Authority Area."	Clarifies how and when information is provided from GOP in the BA Area.
16	Balancing Authority	Added new Relationship: New Relationship No. 2: "Ahead of Time: Receive operational data from Generator Operators within the Balancing Authority Area."	Clarifies how and when information is provided from the GO in the BA Area.
17	Balancing Authority	Deleted Relationship No. 2: Duplicative ~~"Receive operating and availability status of generating units from Generator Operators within the Balancing Authority Area."~~	Covered in Relationship No. 14
18	Balancing Authority	Revised Relationship No. 10: Removed GOP. "Implements generator commitment and dispatch schedules from the Load-Serving Entities ~~and Generator Operators~~ who have arranged for generation within the Balancing Authority Area."	Removed GOP because the information is from the LSE, not the GOP. The GOP operates the generator, the LSE has the schedule.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
19	Balancing Authority	Added new Relationship: New Relationship No. 1: "Receive reports on frequency regulating equipment from Generator Operators within the Balancing Authority Area."	Clarifies how and when information is provided associated with frequency regulation from the GOP in the BA Area.
20	Transmission Operator	Revised Task No. 8: "Adjust Real Power, Reactive Power and voltage ~~flow control devices within the transmission area~~ to maintain reliability."	Revised language to improve clarity regarding the task performed, while not limiting or specifying "how" the TOP maintains parameters to ensure reliability.
21	Transmission Operator	Deleted Task No. 9: Duplicative. ~~"Deploy reactive resources to maintain transmission voltage within defined limits."~~	Repeat of Task No. 8.
22	Transmission Operator	Added new Task: New Task No. 9: "Determine the Transmission capability that supports the Reliable Operation of the Transmission Operator Area."	Additional task supports the required Transmission capability assessments required to be completed by the TOP.
23	Transmission Operator	Added new Task: New Task No. 10: "Operate or direct the operation of Transmission Facilities in its TOP Area."	Additional task necessary to correctly identify the TOP responsibilities associated with the operation of the Transmission System.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
24	Transmission Operator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 14: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 15: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 14: Additional task necessary to identify TOP reliability related responsibilities associated with cyber and physical security. New Task No. 15: Additional task necessary to identify TOP communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
25	Transmission Operator	Revised Relationship No. 11: "Ahead of time: Provides Total Transfer Capabilities, and System Operating Limits, and methodology for calculating to, and coordinates Available Transfer Capability for respective Transmission paths to with, Transmission Service Provider."	Revised language to improve clarity of the functional relationship.
26	Transmission Operator	Revised Relationship No. 12: "Ahead of time: Receives operating and availability status of generating units from Generatorion Operators including status of automatic voltage regulators and power system stabilizers."	Added "and power system stabilizers" to identify the need of the TOP to be aware of component status.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
27	Transmission Operator	Added new Relationship: New Relationship No.13: "Ahead of time: Receive operational data from Generator Operators."	Additional relationship necessary to ensure that the TOP has all necessary operational data to support Operations Planning functions and real-time contingency analysis.
28	Transmission Operator	Revised Relationship No. 18: "Real-time: Deploy~~s~~ reactive resources from Transmission Owners, ~~and~~ Generator Owners, and Distribution Providers to maintain acceptable voltage profiles."	Relationship expanded to include the DP as an operating authority for reactive resources.
29	Transmission Operator	Added new Relationship: New Relationship No.24: "Real-time: Receive Real-time operating information from Generator Operators."	Additional relationship necessary to ensure that the TOP has all necessary operational data to support real-time contingency analysis.
30	Interchange Coordinator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 9: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 10: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 9: Additional task necessary to identify IC reliability related responsibilities associated with cyber and physical security. New Task No. 10: Additional task necessary to identify IC communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
31	Interchange Coordinator	Added new Relationship: New Relationship No. 7: "Receive reliability alerts from the Reliability Coordinators."	This was a missing reciprocal relationship to an existing RC relationship.
32	Transmission Service Provider	Revised Task No. 2: "Determine and post available transfer ~~capability~~ capacity values."	Changed capability to capacity to avoid Glossary conflict.
33	Transmission Service Provider	Added new Task: New Task No. 5: "Acquire Ancillary Services to support Transmission Service."	Added task to recognize provider of last resort responsibilities for required Ancillary Services to support Transmission Services in the Open Access Transmission Tariff.
34	Transmission Service Provider	Added new Task: New Task No. 6: "Update information that is relevant to a long-term Transmission Service arrangement."	Added task to support an existing reciprocal relationship with TP.
35	Transmission Service Provider	Added new Relationship: New Relationship No. 1: "Ahead of Time: Receive the methodology to determine available transfer capacity from the Transmission Operator."	Added relationship to recognize TOP responsibility to develop methodology.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
36	Transmission Service Provider	Revised Relationship No. 1: "Ahead of Time: Receive~~s~~ Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from ~~Planning Coordinator,~~ the Transmission Planner, Transmission Operator and Reliability Coordinator, and coordinates ~~A~~available ~~T~~transfer capacity ~~Capability~~ with these entities and other Transmission Service Providers."	Deleted PC. Changed ATC to available transfer capacity to avoid Glossary conflict.
37	Transmission Service Provider	Revised Relationship No. 3: "Ahead of Time: Receive~~s~~ ~~t~~Transmission expansion plans identified by the Transmission Planner(s)~~Planning Coordinator~~ to help determine ability to accommodate long-term transmission service requests."	Changed PC to TP.
38	Transmission Service Provider	Added new Relationship: New Relationship No. 4: "Ahead of Time: Arrange for providers of Ancillary Services, and notify the Transmission Operator and Balancing Authority."	Supports newly added task to provider of last resort responsibilities for required Ancillary Services to support Transmission Services in the Open Access Transmission Tariff.
39	Transmission Service Provider	Added new Relationship:	Supports newly added task to provider of last resort responsibilities for required Ancillary Services to support Transmission Services in the Open Access Transmission Tariff.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		New Relationship No. 15: "Notify the Transmission Operator and Balancing Authority of changes to Ancillary Services."	
40	Transmission Owner	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 6: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 7: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 6: Additional task necessary to identify TO reliability related responsibilities associated with cyber and physical security. New Task No. 7: Additional task necessary to identify TO communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
41	Transmission Owner	Revised Relationship No. 1: "Coordinates with Transmission Planners and the Planning Coordinator, Generator Owners, other Transmission Owners, and Load-Serving Entities desiring to connect with the Bulk Electric System."	Deleted GO and LSE. Clarified scope.
42	Transmission Owner	Revised Relationship No. 9: "Develops interconnection agreements with the Distribution Providers and Generation Owners for connecting to the Bulk Electric System."	Deleted LSE.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
43	Distribution Provider	Revised Task No. 1: "Provide and operate electrical delivery ~~f~~Facilities between the ~~t~~Transmission system and the ~~E~~end-~~u~~Use ~~C~~customer or distribution-connected energy resource."	Added "distribution-connected energy resource" to recognize increasing number of these types of resources that impact the amount of energy supplied to the BES.
44	Distribution Provider	Added New Task: New Task No. 2: "Identify and characterize its connected load and energy resources."	DP should understand the characteristics of the load and resources connected to its system, which can have an impact on the BES performance.
45	Distribution Provider	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 7: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 8: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 7: Additional task necessary to identify DP reliability-related responsibilities associated with cyber and physical security. New Task No. 8: Additional task necessary to identify DP communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
46	Distribution Provider	Revised Relationship No. 1: "Ahead of time: Coordinate~~s~~ with Transmission Planners on interconnected load and energy	Added energy resources instead of only load.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		resources to support ~~t~~Transmission analysis~~expansion~~."	
47	Distribution Provider	Revised Relationship No. 3: "Ahead of time: Coordinate~~s~~ with ~~E~~end-use ~~C~~customers, distributed energy resources, and Load-Serving Entities to identify new ~~f~~Facility connection needs."	Added "distribution-connected energy resource" to recognize increasing number of these types of resources that impact the amount of energy supplied to the BES.
48	Distribution Provider	New Relationship added: New Relationship No. 7: "Ahead of time: Provide protective relaying systems, under-frequency Load shedding systems, under-voltage Load shedding systems, and Remedial Action Schemes as defined by the Transmission Planner and Planning Coordinator."	Relationship added to support existing Task No. 4
49	Distribution Provider	New Relationship added: New Relationship No. 8: "Real-time: Obtain voltage and power factor requirements from the Transmission Operator."	Relationship added to support existing Task No. 6
50	Generator Operator	Revised Task No. 5: "Support Interconnection frequency and voltage."	Accounted for GOP task of contributing to voltage support.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
51	Generator Operator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 6: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 7: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 6: Additional task necessary to identify GOP reliability related responsibilities associated with cyber and physical security. New Task No. 7: Additional task necessary to identify GOP communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
52	Generator Operator	Revised Relationship No. 3: "Ahead of Time: Provide~~s~~ availability and operating ~~and availability~~ status of generator~~ing~~ Facilities~~units~~ to Reliability Coordinator, Balancing Authority and Transmission Operators for reliability analysis."	Added RC.
53	Generator Operator	Revised Relationship No. 4: "Ahead of Time: Report~~s~~ status of automatic voltage regulating equipment and power system stabilizer equipment ~~or frequency regulating equipment~~ to Transmission Operators."	Deleted frequency regulating equipment; added as a new task.
54	Generator Operator	Added new Relationship:	Added new Relationship to support existing Task.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		New Relationship No. 5: "Ahead of Time: Report on frequency regulating equipment to Balancing Authority."	
55	Generator Operator	Revised Relationship No. 5: "Ahead of Time: Provides operational data to Reliability Coordinator, Balancing Authority and Transmission Operator."	Added BA and TOP.
56	Generator Owner	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 5: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 6: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 5: Additional task necessary to identify GO reliability related responsibilities associated with cyber and physical security. New Task No. 6: Additional task necessary to identify GO communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
57	Generator Owner	Revised Relationship No. 2: "Provide~~s~~ Facility~~unit~~ maintenance schedules and ~~unit~~ generator Facility retirement plans to the Reliability Coordinator, Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner."	Added RC.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
58	Generator Owner	Revised Relationship No. 7: "Revises the generator~~ion~~ maintenance plans as requested by the Balancing Authority, Transmission Operator, and Reliability Coordinator."	Added BA and TOP.
59	Purchasing-Selling Entity	Added New Relationship No. 1: Arrange for energy and capacity from Generator Owners.	Added missing reciprocal relationship for Task No. 1.
60	Load-Serving Entity	Revised Task No. 3: "Identify and communicate ~~Participate in under-frequency load shedding systems and under-voltage load shedding systems through identification of~~ critical customer loads that are to be excluded from the load shedding systems."	Added communication element.
61	Load-Serving Entity	Revised Relationship No. 1: "Ahead of Time: Submit~~s~~ load data~~profiles and characteristics, plans, and forecasts~~ as needed to the appropriate entity (*e.g.*, Balancing Authorities, ~~Purchasing-Selling Entities, Planning Coordinator,~~ Resource Planners, and Transmission Service Providers~~Planners~~) in	Link the load data submission need and types to applicable tariff, interconnection agreements or other arrangements as opposed to a generic set.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		accordance with applicable tariffs, interconnection agreements or other arrangements."	
62	Load-Serving Entity	Revised Relationship No. 2: "Ahead of Time: Coordinate with Distribution Provider to identify critical loads that are to be excluded from load-sheddingIdentifies new facility connection needs for End-use Customers."	Clarify that the DP is the entity impacted by the identified information.
63	Load-Serving Entity	Revised Relationship No. 12: "Real-time: Receives requests from the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider for voluntary load cCurtailment."	Added RC and TOP, who also make these requests.
64	Load-Serving Entity	Revised Relationship No. 13: "Real-time: Communicate requests for voluntary load cCurtailment to end-use customers as directed by the Reliability Coordinator, Balancing Authority, Transmission Operator and Distribution Provider."	Added RC and TOP, who also make these requests.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Functional Model Technical Document

Version 6~~5~~

Prepared by the Functional Model Advisory Group
Approved by the Standards Committee: [Month, Year]

RELIABILITY | ACCOUNTABILITY






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Introduction

The Functional Model Technical Document (FMTD) ~~This document~~ is intended as a companion to Version ~~5~~ 6 of the Functional Model to help explain the functions, including the functional entities, the respective tasks performed by each functional entity, and the relationships with other functional entities that are necessary to perform the tasks. ~~the reader better understand the Model's Functions, functional entities and their relationships. This document therefore provides context, explanation and opinions. It is a companion to, rather than a formal part of, Version 5 of the Model.~~

Section I – Functional Entity Tasks and Interrelationships provides details regarding the functional entity tasks and interrelationships. ~~about each of the Responsible Entities.~~ A number of the ~~Some~~ functional entities, such as the Transmission Owner or Purchasing-Selling Entity, are adequately described in the FM~~unctional Model document~~, so~~and~~ there is no need to provide further ~~little~~ detail in the FMTD~~to add here~~. Other entities, such as the Interchange Coordinator and Balancing Authority, are more complex, including their ~~both unto themselves and in their~~ relationships with other functional entities, and the FMTD ~~is document~~ provides further explanation regarding how these entities work together to ensure reliability~~additional explanations~~.

Section II – Technical Discussion includes technical discussions on related topics such as managing Arranged and Confirmed Interchange, and functional entity areas and boundaries~~y conditions~~. ~~The discussion of Market Operations illustrates that the Model applies to different market structures.~~

SECTION I – FUNCTIONAL ENTITY TASKS AND INTERRELATIONSHIPS

~~Version 4 of the Model, issued in 2008, clarified the concept of responsibility in the Model, as reflected in the use of the term Responsible Entity. In particular, it was clarified that while there were responsibilities of the entities in the Functional Model within the context of the Model itself, the responsibilities that will actually apply to an organization will be determined within NERC's registration, certification and compliance processes and Reliability Standards, not by the Model.~~

~~However, it subsequently became apparent to the Functional Model Working Group that having two different contexts for responsibility did not completely eliminate the potential for confusion. On this basis, Version 5 goes one step further and eliminates reference to responsibility within the Model, replacing the term responsible entity with the term functional entity. In Version 5 of the Model, an entity is defined by the functions it performs.[1]~~

~~As a result of refocusing the Model on Tasks rather than responsibility, Version 5 of the Technical Document has removed discussions associated with responsibility of individual organizations. These matters are now addressed within the context of NERC's registration and compliance programs, typically within the NERC Rules of Procedure. These include situations where:~~

- ~~an organizations may "bundle" a number of different functions and register as the corresponding functional entities, for example Reliability Coordinator and Transmission Operator~~
- ~~two or more organizations may register jointly with NERC as functional entities and thereby divide or share responsibility for meeting standards requirements (Joint Registry Organizations)~~
- ~~an organization may register and assume responsibility for Tasks performed by others, such as a rural cooperative on behalf of its members.~~

~~[1] Version 5 of the Model uses the term "functional entity" to apply to the *entity described in the Functional Model* (Balancing Authority, etc). It is proposed that other NERC documents follow this usage, and also that they use the terms "registered entity", "certified entity" and "responsible entity", in reference to *specific organizations*. For example, PJM is a registered entity and certified entity for the Balancing Authority functional entity.~~

Part 1 - Reliability Coordinator

The Reliability Coordinator~~'s~~ purview must be broad enough to enable it to ~~calculate~~ establish Interconnection Reliability Operating Limits, which will involve ~~s~~System and facility operating parameters beyond its own Area as well as within it. This is in contrast to the Transmission Operator, which also maintains reliability, but is directly concerned with system parameters within its own Area.

The Reliability Coordinator is the highest operating authority; the underlying premise is that reliability of a wide-area takes precedence over reliability of any single local area. Only the Reliability Coordinator has the perspective/vision necessary to act in the interest of wide-area reliability.

The Reliability Coordinator also assists the Transmission Operator in monitoring for and relieving equipment or facility overloads through transmission loading relief measures if market-based dispatch procedures are not effective.

Role in Interchange. The Reliability Coordinator does not receive tags, but may curtail Interchange Transactions until they are arranged and ready for implementation as Interchange Schedules. As such, it does not approve or deny tags. However, once the Reliability Coordinator receives the Interchange Schedule information, it will have the necessary information to aid its assessment of the impacts of flowing and impending Transaction Schedules on its area's reliability. As necessary, the Reliability Coordinator may issue transmission loading relief requests (or similar requests for congestion management) which may result in reducing, removing or halting flowing or impending Interchange Transactions. This is viewed by some as "denying" the Interchange Transactions although in this context, the "denial" is not provided during the collection of approval stage.

Day-ahead analysis. The Reliability Coordinator will receive the dispatch plans from the Balancing Authority(ies) on a day-ahead basis. The Reliability Coordinator will then analyze the dispatch from a transmission reliability perspective. If the Reliability Coordinator determines that the Balancing Authority's dispatch plans will jeopardize transmission reliability, the Reliability Coordinator will work with the Balancing Authority to determine where the dispatch plans need to be adjusted. The Reliability Coordinator obtains generation and transmission maintenance schedules from Generator Operators and Transmission Operators. The Reliability Coordinator has final authority in coordination and resolution of conflicts regarding transmission and generation outage requests. The Reliability Coordinator can deny a transmission outage request and some elective, generation outage requests if a transmission system reliability constraint would be violated.

The Transmission Operator is responsible for the reliability of its "local" transmission system in accordance with establishing and maintaining System Operating Limits (SOLs).However, in some circumstances, as noted above for reliability analysis associated with generation dispatch instructions, the Reliability Coordinator may become aware of a potential SOL ~~violation~~ exceedance and issue a dispatch adjustment. Therefore, in this context, the Reliability Coordinator also has a role regarding the Transmission Operator's management of SOL exceedances.

Emergency actions. The Reliability Coordinator is responsible for Real-time system reliability, which includes calling for the following emergency actions:

- Curtailing Interchange Schedules
- Directing re-dispatch to alleviate congestion or other SOL exceedances

- Mitigating energy and transmission emergencies
- Ensuring energy balance and Interconnection frequency
- Directing load shedding.

The Reliability Coordinator, in collaboration with the Balancing Authority and Transmission Operator, can invoke public appeals, voltage reductions, ~~d~~Demand-~~s~~Side ~~m~~Management, Energy Emergency alerts, and even load shedding if the Balancing Authority cannot achieve resource-demand balance.

System restoration actions. The Reliability Coordinator directs and coordinates ~~system~~ restoration of the BES for its RC Area, with Transmission Operators, ~~and~~ Balancing Authorities and other Reliability Coordinators.

~~**Authority to perform its reliability functions**. The Reliability Coordinator's authority is documented in one or more regional reliability plans, as applicable, for the Region in which the Reliability Coordinator Area is located. In cases where a Reliability Coordinator Area spreads over multiple Regions, its authority will be documented in and accepted by all the concerned Regions through their respective reliability plans.~~

In addition, since the Reliability Coordinator may also have a role regarding the Transmission Operator's management of SOL exceedances, delineation of its authority and that of the Transmission Operator needs to be clearly defined ~~in the reliability plan(s)~~.

Part 2 - Balancing Authority

The Balancing Authority operates within the metered boundaries that establish the Balancing Authority Area. Every generator, ~~t~~Transmission ~~f~~Facility, and end-use customer is in a Balancing Authority Area. The Balancing Authority's mission is to maintain the balance between ~~loads~~ Demand and resources in real time within its Balancing Authority Area by keeping its actual ~~i~~Interchange equal to its scheduled ~~i~~Interchange and meeting its ~~f~~Frequency ~~b~~Bias obligation. The demand~~load~~-resource balance is measured by the Balancing Authority's Area Control Error (ACE). In performing its balancing function, the Balancing Authority does not own the resources.

~~NERC's Reliability Standards require that t~~The Balancing Authority maintains its ACE within acceptable limits. Maintaining ~~resource-d~~Demand-resource balance within the Balancing Authority Area requires four types of resource management, all of which are the Balancing Authority's responsibility. Each of these resource management functions require sufficient resources provided to it by other entities:

- ~~F~~frequency control through tie-line bias
- Regulation ~~s~~Service deployment
- ~~L~~load-following through economic dispatch
- Interchange implementation

Frequency control through ~~t~~Tie-~~l~~Line ~~b~~Bias. To maintain frequency within acceptable limits, the Balancing Authority controls resources within its Balancing Authority Area to meet its ~~f~~Frequency ~~b~~Bias obligation to the ~~i~~Interconnection.

Regulation service deployment. To maintain its ACE within these acceptable limits, the Balancing Authority controls a set of generators within its Balancing Authority Area that are capable of providing ~~r~~Regulation ~~s~~Service.

Load-following through economic dispatch. The organization that serves as the Balancing Authority will in general also perform unit commitment and economic dispatch; however, in some markets, Generator Operators may be permitted to perform unit commitment and economic dispatch among the fleet of generators under their control and within the requirements accepted by the market operator.

Interchange implementation. The Balancing Authority receives Confirmed Interchange from one or more Interchange Coordinators, and enters those Interchange Schedules into its energy management system.

Unit commitment and schedules from Load-Serving Entities. The Balancing Authority receives resource dispatch plans from the Market Operator and/or unit commitment and dispatch ~~s~~Schedules from the Load-Serving Entities that have bilateral arrangements for generation within the market or the Balancing Authority Area. The Balancing Authority provides this commitment and dispatch ~~s~~Schedule to the Reliability Coordinator.

Role in approving Interchange. The Balancing Authority approves an Arranged Interchange with respect to the ramping requirements of the generation that must increase or decrease to implement the Interchange. The Balancing Authority provides its approval or denial to the Interchange Coordinator.

Energy Emergencies. In the event of an Energy Emergency, the Balancing Authority can implement public appeals, ~~d~~Demand-~~s~~Side ~~m~~Management programs, and, ultimately load shedding. Obviously, it must do this in concert with the Reliability Coordinator.

Failure to balance. The Balancing Authority must take action, either under its own initiative or direction by the Reliability Coordinator, if the Balancing Authority cannot comply with NERC's Reliability Standards regarding frequency control and Area Control Error.

~~See "Managing Bilateral Interchange Transactions"~~

Reserve Sharing Groups: In the past, only reserve sharing groups have been associated with Contingency Reserve. However, as the industry has evolved, additional commercial relationships between Balancing Authorities are occurring and thus creating new responsible groups. These responsible groups now include Regulation Reserve Sharing Groups, Frequency Response Sharing Groups, Frequency Response Sharing Groups and Contingency Reserve Sharing Groups. These groups are the responsible entities, but the Balancing Authorities remain responsible for performance within each respective group. The Balancing Authorities enter into commercial arrangements among themselves to form the respective sharing groups.

Part 3 - Planning Coordinator

The Planning Coordinator coordinates and integrates ~~t~~Transmission facility and service plans, resource plans, and protection system plans among the Transmission Planner(s) ~~and Resource Planner(s)~~ within its area of purview. These activities range from review and ~~integration~~ assessing~~of~~ expansion ~~reinforcement~~ and corrective action plans developed by the Transmission Planner(s) ~~functional entities whose area of responsibility is~~ within the Planning Coordinator's area ~~with respect to established reliability needs to providing procedures, protocols, modeling and methodology software, etc. for consistent use within its area~~. The assessment should consider the interaction of system changes under a range of selected scenarios across the entire Planning Coordinator area. The PC assessment includes the collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one Transmission Planner; however, the area under the purview of a Planning Coordinator may include as few as one Transmission Planner. The Planning Coordinator's scope of activities is intended to span a broader area that may include BES assets of multiple Transmission Planners. All BES Facilities should be assigned to a Transmission Planner and to a Planning Coordinator, so that there are no gaps in the assessment of the BES.

Planning Coordinators work through a variety of processes to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all portions of the interconnected BES are completely coordinated for planning activities. While much of what the Planning Coordinator performs could be actually performed by a Transmission Planner, such as developing methodologies in conjunction with surrounding Transmission Planners, recognition of resource plans, assessing system performance consistent with reliability needs by itself, and collaborating with other Transmission Planners to assess impacts on the interconnected area, the Planning Coordinator by its very nature will generally take responsibility over a wider perspective than the Transmission Planners for which its coordinates. The Planning Coordinator generally conducts system performance assessments, in collaboration with other Planning Coordinators to consider transfer/flows across multiple Transmission Planner areas or intra- and inter- state areas such as generation dispatch scenarios caused by temperature or fuel extremes. Geographic size is not necessarily a critical consideration, it is the extent and impact of the electrical network that the planners have taken responsibility for assessing that determines whether an area is large enough for analysis and planning

~~Although the Functional Model sets forth the concept of the Planning Coordinator and how a functional entity could perform as such, there may be situations or circumstances under actual organizational structures whereby a single entity does not exist that performs the Reliability Planning Function but rather the function is taken on by a number of entities, *e.g.*, a group of Transmission Planners, or an organization such as a regional group formed within a region or possibly the Regional Entity itself. In all these cases the Reliability Planning Function is still performed in some manner by some entity or organization.~~

The boundaries for the Planning Coordinator area are basically defined by the location of the Bulk Electric System facilities under the purview of the Planning Coordinator, *i.e.* those facilities for which the Planning Coordinator coordinates and evaluates and recommends reinforcement and corrective plans resulting from studies and analysis of system performance and interconnection of facilities. The BES facilities under its purview, are generally contiguous and cover in aggregate the same areas as the Transmission Planners its coordinates. Traditionally transmission planning has been associated with one or more Transmission Owners, *i.e.* reinforcement and corrective action plans must be associated with certain Transmission Owner facilities. Since transmission ownership may cross state or provincial or regional boundaries, the BES ~~f~~Facilities on one side of the Transmission Owner boundary may be in one Planning Coordinator area

whereas the remaining facilities may be in another. As such the Planning Coordinator area is not constrained to fit within a Reliability Coordinator or Transmission Operator Area. However, the Planning Coordinator area must cover at least one Transmission Planner Area. ~~and one Resource Planner area, or part thereof if either or both of these planner areas is larger than the Planning Coordinator area. On the other hand, there is the possibility that a Planning Coordinator area could be nested inside an even larger Planning Coordinator area provided the smaller Planning Coordinator does in fact perform the appropriate system assessments. In this special case, the larger Planning Coordinator would perform the ultimate planning coordinating function for all the Resource Planners, Transmission Planner and smaller Planning Coordinator in its Area. As an example, some ISOs and RTOs perform the Reliability Planning Functions but they are also under the purview of the Regional Entity that also performs the Reliability Planning Functions at a broader scale.~~

In many areas, there may exist more than one Transmission Planner ~~and Resource Planner, as well as a nested Planning Coordinator, within a Planning Coordinator area,~~ each performing a different role demarcated primarily by their particular function and scale (area-wise) of assessments performed. In order to ensure all BES Facilities are associated with a Planning Coordinator, clear delineation of the "PC Area" should establish the BES Facilities and associated connections to its adjacent Planning Coordinators. ~~In these cases, delineation of the role of the various functional entities needs to be clearly defined in the regional reliability plan(s).~~

The Planning Coordinator is not responsible for implementing the ~~t~~Transmission and resource plans. However, it helps to facilitate the process whereby adequate resources and ~~t~~Transmission ~~f~~Facilities are placed into service in a timely and efficient manner through coordinated planning with the ~~Resource Planners,~~ Transmission Planners~~, and possibly others through the coordinated planning process~~.

Part 4 - Transmission Planner

The Transmission Planner develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.[2] ~~area of purview.~~

The Transmission Planning function is typically associated with the Transmission Ownership function. The Transmission Planner performs the tasks of modeling, simulating and assessing the performance of the Transmission system under a range of future scenarios on a recurring basis. As Transmission system performance deficiencies are identified through this process, the Transmission Planner studies alternative solutions for correcting the deficiencies. Through interactions with various stakeholders, the Transmission Planner ultimately arrives at a recommended Corrective Action Plan that will resolve the identified deficiencies. For solutions that involve Transmission system capacity expansion, the associated Transmission Owner(s) is responsible for implementing the solution.

Both the Transmission Planner and Planning Coordinator perform assessments to evaluate whether future Transmission system performance will meet the minimum acceptable system performance requirements. The Transmission Planner and Planning Coordinator may consider different system conditions (and BES Facilities) in performing their assessments. This flexibility allows the Transmission Planner and Planning Coordinator to study a wider range of system conditions, which leads to a more complete and comprehensive assessment of the BES. For example, a Transmission Planner may set higher System performance criteria for a particular area under assessment.

The Transmission Planner assessment includes the collection of Transmission assets over which the Transmission Planner is responsible for planning ("TP Area"). The Planning Coordinator assessment includes the collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one TP. Every Facility must have one associated Transmission Planner and at least one Planning Coordinator. This means that every Facility in the TP Area should be included in the assessment conducted by the TP.

As noted above, this typically aligns with the Transmission system facilities owned by an associated Transmission Owner(s). Because of the interconnected nature of the Bulk Electric System, the Transmission Planner works with other Transmission Planners to periodically update power system models used to perform simulations. Information needed to update these models is collected from various functional entities within a particular Transmission Planner's area of purview. Power system modeling data is also "rolled up" by the Transmission Planner(s) to the Planning Coordinator to support development of Interconnection level models.[3] ~~, *i.e.*, those facilities for which the Transmission Planner develops reinforcement and corrective action plans resulting from studies and analysis of system performance and interconnection of facilities. This means that the Transmission Planner's area is not defined by the extent of the models it uses or studies that it performs since any planner can assess and perform simulations on readily available interconnection wide models. The BES facilities in its area, *i.e.*, under its purview, are generally contiguous.~~

[2] Definition of Transmission Planner (effective July 1, 2016) from the NERC Glossary of Terms. In the Glossary, Planning Coordinator and Planning Authority are defined interchangeably.

[3] In some instances, the same entity may serve as both a Transmission Planner and Planning Coordinator.

~~Traditionally transmission planning has been associated with one or more Transmission Owners, *i.e.*, reinforcement and corrective action plans must be associated with the facilities of certain Transmission Owners. In some cases where transmission ownership crosses a state line, the BES facilities on one side of a geographic boundary line may be in one Transmission Planner Area while the remaining facilities may be in another. As such, the Transmission Planner Area is not constrained to fit within one Reliability Coordinator or Transmission Operator Area. However, the Transmission Planner Area can only be smaller than or equal to the area of its related Planning Coordinator.~~

~~Develop Transmission Expansion Plans~~. The Transmission Planner evaluates the impact of ~~facilities that will be needed in response to~~ long-term ~~requests for t~~Transmission ~~s~~Service requests, and the ~~needed to~~ integration~~e~~ of new generation, ~~t~~Transmission, and end-use customers, ~~into the Bulk Electric Systems~~on the planned Transmission system performance. In evaluating requests ~~developing plans~~ for long-term ~~t~~Transmission ~~s~~Service or~~and~~ new interconnection~~s requests~~, the Transmission Planner is expected to coordinate ~~plans or engage in joint planning~~ with other Transmission Planners, as appropriate, to ensure new service/facilities do not adversely affect the reliability of neighboring ~~t~~Transmission systems.

~~Based on customer requests for transmission service, native load growth, changes in existing native load, and the planning procedures and protocols established for their Transmission Planning Areas, the Transmission Planners will develop transmission plans to accommodate long-term firm transmission service requests and native load requirements with due regard to established reliability needs. While developing these plans, the Transmission Planner may provide alternate solutions and evaluate alternatives suggested by entities requesting customer service.~~

The Transmission Planner~~s~~ provide~~s~~ its assessment results ~~transmission plans~~ to ~~its~~ the appropriate Planning Coordinator for review to ensure that the impacts on the interconnected systems are duly addressed. In reporting its ~~transmission expansion plan~~assessment results to the Planning Coordinator, the Transmission Planner is expected to assess whether its plans for new or reinforced facilities meet reliability needs or whether corrective plans are necessary. The Transmission Planners work with the Planning Coordinator to identify potential alternative solutions, including solutions proposed by stakeholders, to meet interconnected Bulk Electric System requirements.

Part 5 - Resource Planner

The Resource Planner develops a long-term (generally 1 year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Resource Planner area. Note: The term "resource" is to be understood to include supply resources and demand-side resources (such as dispatchable loads).

The boundaries for the Resource Planner area are basically defined by the location of the specific loads being considered for resource adequacy. The loads under considerations are generally contiguous and form the fundamental input for analysis of resources such as loss of load studies. The Resource Planning function may be performed by one or more Resource Planners within a Planning Coordinator area, Transmission Planner or Reliability Coordinator Area; however, the Resource Planning Function could be performed by one Resource Planner that covers one, or more than one, Planning Coordinator area, Transmission Planner Area or Reliability Coordinator Area. As such the Resource Planner area is not constrained to fit within the footprint of any other functional entity. The analysis and development of resource plans by their very nature will need to consider generation capacity and other resources outside the area defined by the specific loads as well as the transmission capability to access those resources.

In some markets, market rules may require the same organization to assume the role of both the Planning Coordinator and the Resource Planner. For example, in those markets where there are no entities responsible for or obligated to serve load, the Planning Coordinator will generally assume the Resource Planner's role. In these cases, the Planning Coordinator identifies the need for additional resources to be provided by the market and performs the Resource Planning Function.

Types of Resource Planning

Resource planning, in a generic sense, may be divided into two types:

- Planning conducted by an organization under the authority of legislation, regulation order, tariff or market rule. Such planning will typically be conducted in an open process and subject to industry, public and stakeholder review. It will have as one objective, ensuring resource adequacy.
- Planning directed to identifying and realizing commercial opportunities. Such plans will typically be commercially sensitive, may not be made public before required for the plan to be implemented, and will not be directed to ensuring resource adequacy.

The Resource Planner described in the Model is associated with the former type of planning, *i.e.*, planning having a mandate to ensure resource adequacy.

The latter type of planning, which is driven primarily by commercial opportunity, may be viewed as an activity associated with generation ownership. However, resource planning that is purely commercially-driven clearly will have an impact on resource adequacy. The Resource Planner, with its mandate for resource adequacy, must reflect to the extent possible commercially-directed planning affecting its Resource Planner area.

Part 6 - Transmission Operator

The Transmission Operator acts or authorizes action to connect to, disconnect from or reconfigure (switching operations) Facilities classified as Transmission assets, as described by the following:

a. Actions may include direct or indirect control of Transmission assets from a Control Center to conduct operations during Normal and Emergency conditions.

b. Authorizations to act may include orders directing designated field personnel with Transmission System switching responsibilities to perform switching operations on Facilities classified as Transmission assets during Normal and Emergency conditions.

The Transmission Operator ~~operates or directs the operation of transmission facilities, and~~ maintains local-area reliability, that is, the reliability of the system and area for which the Transmission Operator has responsibility. The Transmission Operator achieves this by operating the ~~t~~Transmission system within its purview in a manner that maintains proper voltage profiles and System Operating Limits, and honors ~~t~~Transmission equipment limits established by the Transmission Owner. The Transmission Operator is under the Reliability Coordinator's direction respecting wide-area reliability considerations, that is, considerations beyond those of the system and area for which the Transmission Operator has responsibility and that include the systems and areas of neighboring Reliability Coordinators. The Transmission Operator, in coordination with the Reliability Coordinator, can take action, such as implementing voltage reductions, to help mitigate an Energy Emergency, and can take action in ~~s~~System restoration.

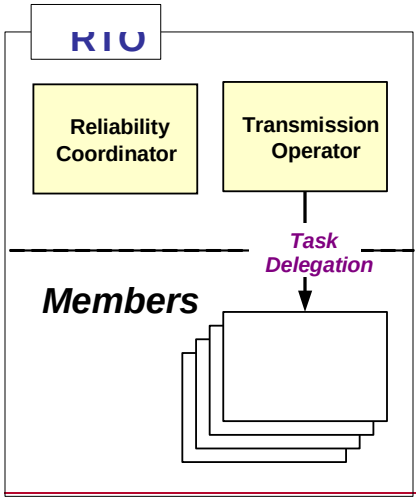
~~Note that the Model does not attempt to define what is and isn't a transmission facility, versus a generating facility. As discussed in Section II-13, this is assumed to be defined elsewhere by NERC or by governmental authorities.~~

~~**Maintenance**. The Transmission Owner provides the overall maintenance plans and requirements for its equipment, specifying, for example, maintenance periods for its transformers, breakers, and the like. The Transmission Owner then develops or arranges for the development of the detailed maintenance schedules (dates and times) based on the Transmission Owner's maintenance plans and requirements, and provides those schedules to the Reliability Coordinator and others as needed.~~

~~The organization serving as Transmission Operator may also physically provide or arrange for transmission maintenance, but it does this under the direction of the Transmission Owner, which is ultimately responsible for maintaining its owned transmission facilities.~~

~~**Bundled with the Reliability Coordinator or Transmission Owner**. A single organization may be the functional entity for multiple Functions. In such a case, the functional entities are said to be "rolled up" or "bundled" into a single organization. An organization may be a Transmission Operator without being a Reliability Coordinator or Transmission Owner. However, in many cases the Transmission Operator is bundled with one of these functional entities.~~

~~**Bundled with Reliability Coordinator**. For example, consider an RTO with several members. The RTO registers with NERC as a Reliability Coordinator and Transmission Operator and is NERC-certified for both. The RTO then delegates/assigns some of the Transmission Operator Tasks to its members.~~



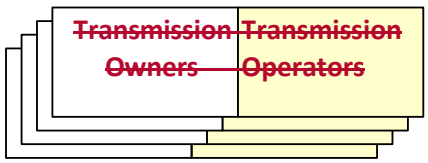
~~***Figure 1 – Transmission Operator bundled with Reliability Coordinator***~~

~~**Bundled with the Transmission Owner**. In other situations, the RTO registers with NERC as the Reliability Coordinator, and its members register as Transmission Owners and Transmission Operators, as shown in Figure 2. In this case, the Model views the RTO as responsible for complying with Reliability Standards associated with the Reliability Coordinator and would be NERC-certified as such. The RTO members would be responsible for complying with all Reliability Standards associated with the Transmission Operator, and would be NERC certified as such.~~

~~**RTO**~~

~~**Reliability Coordinator**~~

~~***Members***~~



~~***Figure 2 – Transmission Operator bundled with Transmission Owner***~~

Part 7 - Interchange Coordinator

The e-tagging process exists for scheduling Transmission usage by entities who have contracted for Transmission access. NAESB maintains the e-tagging specification. The Interchange Coordinator is equivalent to the tag authority described in the specification. (NAESB states this service has been assigned to the Sink Balancing Authority. The functional model envisions that the Sink Balancing Authority may serve as its own Interchange Coordinator or have this service provided by a separate organization.)

The "authority service"[4] is the focal point for all interactions with an e-Tag and maintains the single authoritative "copy of record" for each e-Tag received. Every Sink Balancing Authority is responsible for registering the URL of an "authority service." The authority service forwards all valid received RFI to each entity identified in the transaction as having "approval" or "viewing" rights over that RFI, and collects approvals/denials issued by these approval services. Based on time and the message(s) received from the approval services, the authority service arbitrates and sends the final disposition of the request to each entity in the distribution list. The authority service also provides the capability for both the agent (requestors of service) and approval services to interrogate the current approval state of any transaction RFI on demand.

~~The Interchange Coordinator collects approvals or denials for Arranged Interchange from Balancing Authorities and Transmission Service Providers and verifies the validity of the source and sink. The NERC Tag Authority provides this service that had been assigned to the Sink Balancing Authority.~~

~~The Interchange Coordinator provides the Balancing Authority with the individual bilateral Arranged Interchange. The Balancing Authority must track the individual Interchange Schedules in case one or more of them are curtailed by the Reliability Coordinator or by the Balancing Authority in those cases where a generator or load is interrupted. The Balancing Authority then creates a "net" interchange total for use in its energy management system as well as a "net" interchange for each neighboring Balancing Authority. The net Interchange Schedule for each neighboring Balancing Authority is used by the Receiving Balancing Authority for checkout with the neighboring Balancing Authorities.~~

~~All bilateral Interchange Transactions *that cross a Balancing Authority Area boundary* are coordinated through the Interchange Coordinator.~~

~~While the approval/denial process may utilize tools (such as computer software and communication protocols), the Model envisages that the Interchange function will be assigned to an actual organization. A Balancing Authority may serve as its own Interchange Coordinator or have this service provided by a separate organization.~~

~~**Assessing ramping capability and connectivity**. The Balancing Authority approves/denies the capability to ramp the Arranged Interchange in or out and notifies the Interchange Coordinator. The connectivity of adjacent Balancing Authorities is also verified by the Balancing Authorities before responding to the~~

[4] Definitions from NAESB:
e-Tag Agent Service: Software component used to generate and submit new e-Tags, corrections, and profile changes to an e-Tag Authority Service and to receive state information for these requests.
e-Tag Authority Service: Software component that receives e-Tag Agent Service and e-Tag Approval Service requests and responses and forwards to the appropriate approval service. Also maintains master copy of e-Tag (all associated requests), the composite state of the e-Tag, etc. and responds to queries regarding the e-Tags in its possession.
e-Tag Approval Service: Software component used to indicate individual approval entity responses when requested by the e-Tag Authority Service, as well as submit profile changes.

~~Interchange Coordinator.~~

~~**Ensuring balanced, valid Interchange Transactions**. The Interchange Coordinator also ensures that the resulting Confirmed Interchange Transactions is balanced and valid prior to physical delivery. This means:~~

- ~~The source MW must be equal to the sink MW (plus losses if they are "self-provided"), and~~
- ~~All reliability entities involved in the Arranged Interchange are currently in the NERC registry.~~

~~Only when it receives approvals from the Transmission Service Providers and Balancing Authorities, does the Interchange Coordinator direct the Balancing Authorities to implement the Transaction. If any of these entities TSPs or BAs does not approve the Arranged Transaction, then the Interchange Coordinator does not authorize the Transaction to become Confirmed Interchange.~~

~~**Curtailments**. The Interchange Coordinator coordinates curtailments of Confirmed Interchange ordered by the Reliability Coordinator by notifying the Balancing Authorities, Transmission Service Providers, and Purchasing-Selling Entities. The Interchange Coordinators also communicates and coordinates the resulting modified Arranged Interchange that result from the curtailments.~~

Part 8 - Transmission Service Provider

The Transmission Service Provider authorizes the use of the transmission system under its authority. In ~~most~~ some cases, the organization serving as Transmission Service Provider is also the market operator.

Role in approving Interchange. The Transmission Service Provider approves Arranged Interchange by comparing the ~~t~~Transmission ~~s~~Service previously arranged by the ~~t~~Transmission ~~c~~Customer (Purchasing-Selling Entity, Generator Owner, Load-Serving Entity) with the ~~t~~Transmission information supplied by the Interchange Coordinator. The Transmission Service Provider also ensures that there is a contiguous ~~t~~Transmission path and that adjacent Transmission Service Providers~~SPs~~ are on the ~~s~~Scheduling ~~p~~Path. The Transmission Service Provider then provides its approval or denial to the Interchange Coordinator.

Providing Transmission and Ancillary Service. As its name implies, the Transmission Service Provider provides transmission service and Ancillary Service to transmission customers, such as Generator Owners, Load-Serving Entities, and Purchasing-Selling Entities. The Transmission Service Provider determines Available Transfer Capability based on the established Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits (by various entities including the Planning Coordinator, Transmission Planner, Transmission Operator and Reliability Coordinator), and coordinates ATC with other Transmission Service Providers. The Transmission Service Provider manages the requests for transmission service according to the Transmission Owner's tariff, and within the operating reliability limits determined by the Reliability Coordinator. The Transmission Service Provider ensures necessary Ancillary Services are provided to the Transmission Operator and Balancing Authority. The Transmission Service Provider does not itself have a role in maintaining system reliability in ~~r~~Real time — that is done by the Reliability Coordinator and Transmission Operator and Balancing Authority.

The Transmission Service Provider arranges for transmission loss compensation and Ancillary Service requirements with the Balancing Authority.

Part 9 - Transmission Owner

The Transmission Owner owns its transmission facilities and provides for the maintenance of those facilities. It also specifies equipment operating limits, and supplies this information to the Transmission Operator, Reliability Coordinator, and Transmission Planner and Planning Coordinator.

In many cases, the Transmission Owner has contracts or interconnection agreements with generators or other transmission customers that would detail the terms of the interconnection between the owner and customer.

~~**Relationship with the Transmission Operator**. The organization serving as Transmission Owner may operate its transmission facilities or arrange for another organization (which may or may not be a Transmission Owner) to operate and/or maintain its transmission facilities.~~

Maintenance. The Transmission Owner provides the overall maintenance plans and requirements for its equipment, specifying, for example, maintenance periods for its transformers, breakers, and the like. The Transmission Owner then develops or arranges for the development of the detailed maintenance schedules (dates and times) based on the Transmission Owner's maintenance plans and requirements, and provides those schedules to the Reliability Coordinator and others as needed.

The organization serving as Transmission Operator may also physically provide or arrange for transmission maintenance, but it does this under the direction of the Transmission Owner, which is ultimately responsible for maintaining its owned transmission facilities.

~~See "Transmission Operator," Section "Bundling with the Reliability Coordinator or Transmission Owner"~~

Part 10 - Distribution Provider

The Distribution Provider provides the physical connection between the end-use customers, distribution-connected energy resources, and the BES~~electric system~~, including customers served at ~~t~~Transmission level voltages. The Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. One Distribution Provider may be directly connected to another Distribution Provider, such connections must be reported to the Balancing Authority even though ~~and~~ not directly connected to the BES~~ulk Electric System~~.

The Distribution Provider maintains "local" safety and reliability and is responsible for the distribution facilities to serve end-use customers and distribution-connected energy resources. The Distribution Provider provides the switches and re-closers necessary for emergency action and information necessary for the Transmission Operator and Transmission Planner. The Distribution Provider may need to demonstrate manual ~~l~~Load-shedding capability to the Balancing Authority and Transmission Operator. Design and maintain protective relaying systems, under-frequency load-shedding systems, under-voltage Load-shedding systems, and Remedial Action Schemes that interface with the Transmission system.

~~The same organization may serve as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well.~~ Unlike the Load-Serving Entity, the Distribution Provider has the facilities or assets ("wires") and does not take title to any energy. However, while these functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these functions together.

~~Part 11 – Generator Operator~~

~~The Generator Owner may operate its generating facilities or designate a separate organization to perform the Generator Operation Function.~~

~~The Generator Operator operates, or directs the operation of generation facilities. The Generator Operator supports the needs of the Bulk Electric System up to the limits of the generating facilities in its purview. Ultimately the Generator Operator's role is to meet generation schedules, manage fuel supplies, and provide frequency support and reactive resources without jeopardizing equipment.~~

~~**Relationship with the Generator Owner.** The organization that serves as Generator Operator may also be the owner of the generation facilities it operates, or it may be a separate organization designated by the Generator Owner to operate the facilities. The Generator Operator receives maintenance and performance verification schedules from the Generator Owner, and develops operating and unit commitment plans based on these schedules~~

~~**Relationship with the Transmission Operator.** The Generator Operator provides reliability related services through arrangements or by direction from the Transmission Operator for support of the Bulk Electric System. The Generator Operator provides maintenance schedules, generator status, and AVR status to the Transmission Operator. The Generator Operator receives notification of transmission system problems affecting its generator from the Transmission Operator or Reliability Coordinator.~~

~~**Relationship with the Balancing Authority.** The Generator Operator provides unit commitment schedules, generator status, and operating and availability status of generating units to the Balancing Authority.~~

Relationship with the Reliability Coordinator. The Generator Operator provides annual maintenance plans, and operational data to the Reliability Coordinator. The Generator Operator takes actions based on directives from the Reliability Coordinator for the needs of the Bulk Electric System.

Relationship with Purchasing Selling Entity. The Generator Operator receives notice of Arranged Interchange approved by the Purchasing Selling Entity.

Part 12 – Generator Owner

The Generator Owner owns its generation facilities and provides for the maintenance of those facilities.It also provides verified equipment operating limits and supplies this information to the Generator Operator, Reliability Coordinator, Transmission Planner and Planning Coordinator.

In many cases, the Generator Owner has contracts or interconnection agreements with Transmission Owners or Distribution Providers that detail the terms of the interconnection between these parties.

Relationship with the Generator Operator. The organization serving as Generator Owner may operate generation facilities, or arrange for another organization to do so. In addition, the organization serving as Generator Owner may perform maintenance and facility verification, or may arrange with another organization to do so.

Part 13 – Purchase-Selling Entity

The Purchasing Selling Entity (PSE) arranges for and takes title to energy products (capacity, energy and reliability-related services) that it secures from a resource for delivery to a Load- Serving Entity (LSE). The PSE also arranges for transmission service with the Transmission Service Provider that provides transmission service to the LSE under a tariff or market rule.

The Purchasing-Selling Entity initiates a bilateral Interchange between Balancing Authority Areas by submitting a Request for Interchange (RFI) to the Interchange Coordinator.

Part 14 - Load-Serving Entity

The Load-Serving Entity (LSE) arranges for the provision of energy Resources and Ancillary Services to its Balancing Authority and Resource Planner in order to supply its end-use customers, but does not provide distribution services ("wires"). ~~The LSE defined in the Model is not to be confused with or equated to the LSE as defined in any tariff or market rule.~~

~~Today, o~~Organizations serving as Load-Serving Entities may also be Generation Owners and can self-provide, or have contracts with other Generator Owners for capacity, ~~and~~ energy and Ancillary Services to serve the Load-Serving Entity~~'s~~ customers, or purchase capacity, ~~and~~ energy, and Ancillary Services from non-affiliated Generator Owners through a Purchasing-Selling Entity (or Market Operator), or employ a combination of these three options.

The Load-Serving Entity reports its ~~generation~~ resource (affiliated and non-affiliated) arrangements to serve load to the Balancing Authority, which forwards this information to the Reliability Coordinator, for day-ahead analysis.

The LSE may contract for ~~reliability-related services~~ Ancillary Services through the Transmission Service Provider or the ~~M~~market ~~O~~operator (if the Load-Serving Entity is part of a market or pool) or directly from Generator Owners or loads.

~~The same organization may serve as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well.~~ Unlike the Distribution Provider, the Load-Serving Entity, does not have Bulk Electric System assets ("wires") but does take title to energy. However, while these functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these functions together.

~~The Functional Model assigns to t~~The Load-Serving Entity is responsible for the identification of loads for ~~c~~Curtailment and those critical customer loads that are to be excluded from the load-shedding systems, and the development of load profiles and load forecasts. ~~Please see Section II, 114: Roles in Load Curtailment for more detailed information.~~

The Load-Serving Entity communicates requests for ~~voluntary c~~Curtailment to the appropriate end-use customer loads~~, thereby ensuring that these loads will in fact be curtailed~~.

~~Part 15 – Compliance Enforcement Authority~~

~~NERC is the Compliance Enforcement Authority. The Regional Entities have a major role in the actual performance of the monitoring, under delegated authority from NERC.~~

~~Part 16 – Standards Developer~~

~~The Standards Developer is written to be NERC. The Reliability Standards referenced in the Model consist of standards developed by either NERC or a Regional Entity and that are approved by NERC and subsequently by governmental authorities. This would therefore not include regional reliability criteria that are not submitted to NERC for approval. This is discussed further in Section II.~~

~~Part 17 - Market Operator (Resource Integrator)~~

~~Market Operations is not a reliability Function. It is included in the Model to provide a linkage between reliability Functions and commercial functions. The associated functional entity is the Market Operator (Resource Integrator). The term Resource Integrator replaces Resource Dispatcher used in Version 3 of the Model. This recognizes that integration of resources is the essential feature, not resource dispatch, which is the responsibility of the Balancing Authority.~~

~~The Market Operator is described further in Section II, Technical Discussions.~~

Part 18 - Reliability Assurer

The Reliability Assurer is subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. The Reliability Assurer assures the reliability of the Bulk Power System in North America by developing and enforcing Reliability Standards; annually assessing seasonal and long-term reliability; monitoring the Bulk Power System through system awareness; and, educating, training, and certifying industry personnel.

~~In Version 4 of the Model, the Reliability Assurer entity and the Reliability Assurance Function replaced Version 3's Regional Reliability Organization entity and the Regional Reliability Assurance Function.~~

~~The change to Reliability Assurer reflected the fact that a name specific to the Model is preferable to a name already in use in another context. Moreover, since this Function can be performed on other than a regional basis, the Functional Model allows for the assignment to be made to an organization other than a Regional Entity.~~

~~The changes therefore provide NERC with flexibility in assigning the functional entity for Reliability Assurance.~~

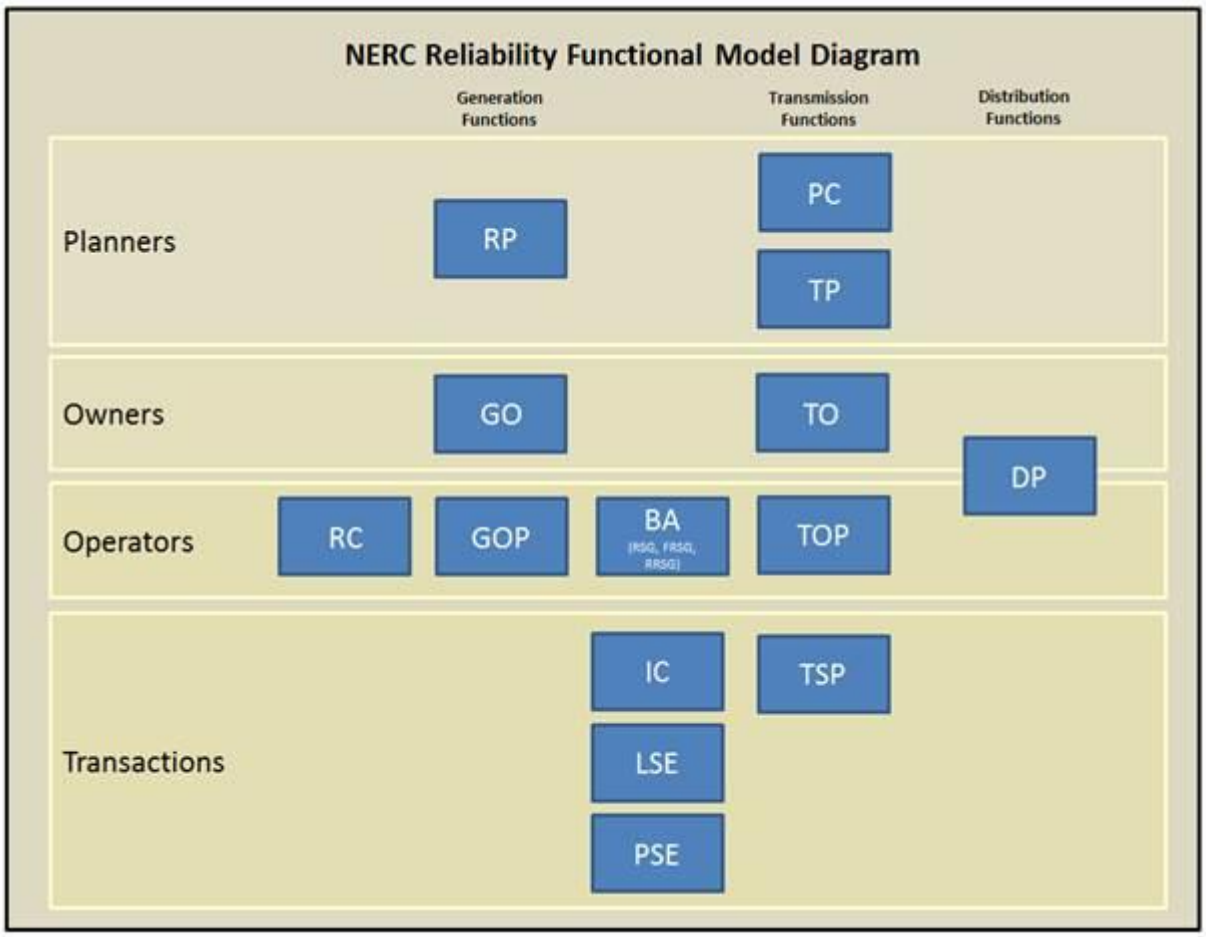
~~The role of the Reliability Assurer may be considered to provide "defense-in-depth." That is, the Reliability Assurer provides an independent assessment of Tasks performed by other functional entities, or facilitates or coordinates such Tasks. While the specific role of the Reliability Assurer is not fully developed at the present time, the following are representative of the Tasks that might be performed:~~

- ~~Perform high level evaluations, such as at a regional or Interconnection level, of transmission and resource adequacy. These evaluations may be based on a review of the plans of Transmission Planners.~~
- ~~Develop regional reliability plans, to ensure there are no reliability gaps, or no missing or ambiguous responsibilities or relationships.~~
- ~~Perform high-level evaluations, such as at a regional or Interconnection level, of protection systems as they relate to the reliability of the Bulk Electric System.~~
- ~~Perform disturbance analysis evaluations.~~

~~The selection of particular Tasks for the Reliability Assurer will reflect NERC's judgment on which Tasks merit such a "defense-in-depth" approach.~~

SECTION 2 – TECHNICAL DISCUSSION

The below diagram provides an illustration of how the various functional entities can be categorized.



~~Part 1 – General Clarifications of the Functional Model~~

~~The general features of the Functional Model are described in the Introduction, Purpose and Guiding Principles sections of the Model. In brief:~~

~~The NERC Reliability Functional Model ("the Model") provides the framework for the development and application of NERC's Reliability Standards, as follows:~~

- ~~The Model describes a set of Functions that are performed to ensure the reliability of the Bulk Electric System. Each Function consists of a set of related reliability Tasks. The Model assigns each Function to a functional entity, that is, the entity that performs the Function's Tasks. The Model also describes the interrelationships between that functional entity and other functional entities (that perform other Functions).~~

- NERC's Standard Development Teams develop Reliability Standards that assign each reliability requirement within a standard to a functional entity, as defined in the Model.
- This is possible because a given standard requirement will be logically related to a Task within a Function. A standards requirement will be very specific whereas a Task will be more general in nature.
- NERC's compliance processes require specific organizations to register as functional entities and comply with standards requirements assigned to the functional entities.
- The Model's Functions and functional entities also provide for consistency and compatibility among different Reliability Standards.

The NERC Reliability Functional Model ("the Model") does NOT address:

- Entity Certification
- Registration
- Compliance
- Sanctions

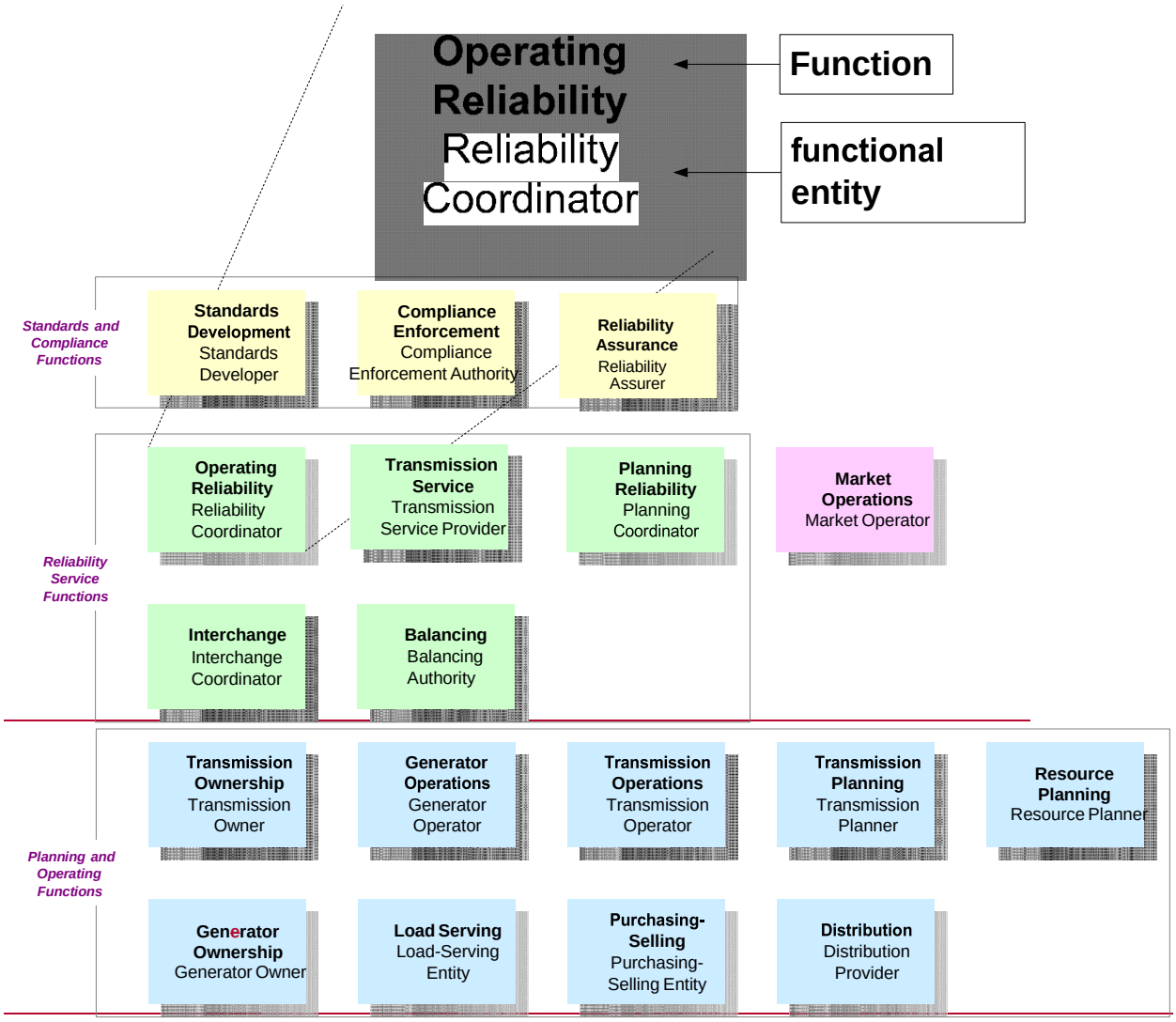
There are a number of clarifications that are important for those involved in developing standards and monitoring compliance with them. These clarifications are generally made in the Model itself, but because of their importance and potential for misinterpretation, they warrant being repeated.

The Model is a guideline, it is not prescriptive. The Model is not a standard, and does not have compliance requirements. The Model is a guideline for the development of standards and their applicability; it is not a NERC requirement. Standards developers are not required to include tasks envisioned in the model, nor are the developers precluded from developing Reliability Standards that conflict with the Model. The Reliability Standards requirements take precedence over the Model.

A Functional Entity is not an actual organization. The Model describes Tasks performed by functional entities, which are in effect generic *classes or categories* of organizations. The Model itself does not address *specific* organizations. The Model, for example, describes the Reliability Coordinator, a functional entity; the Model does not reference PJM and MISO, which are specific organizations. It is through the NERC registration process that the PJM and MISO organizations become a member of the category of organization called Reliability Coordinator, and thereby responsible for meeting standards requirements specified for the Reliability Coordinator.

Reliability is best served if there is consistency of definitions within all NERC documents. These documents include, but are not limited to, the Functional Model, the NERC Rules of Procedure and Glossary of Terms.

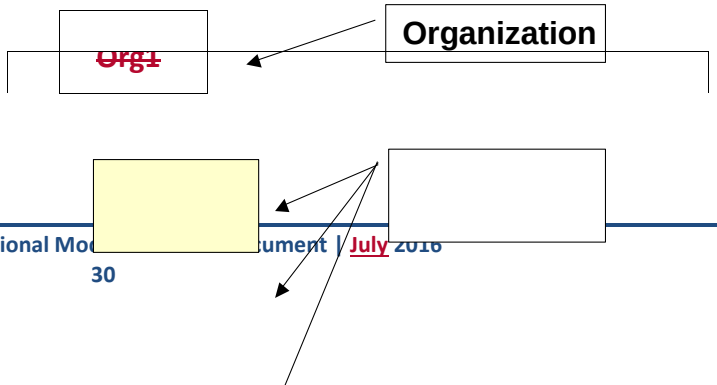
Every Function has an associated functional entity. A Function is a set of related reliability Tasks; whereas the functional entity is the name given to the category of organization that performs these Tasks. The diagram (Figure 3) of the Model includes two names within each Function box. The Function is shown in a larger typeface with the associated functional entity underneath.

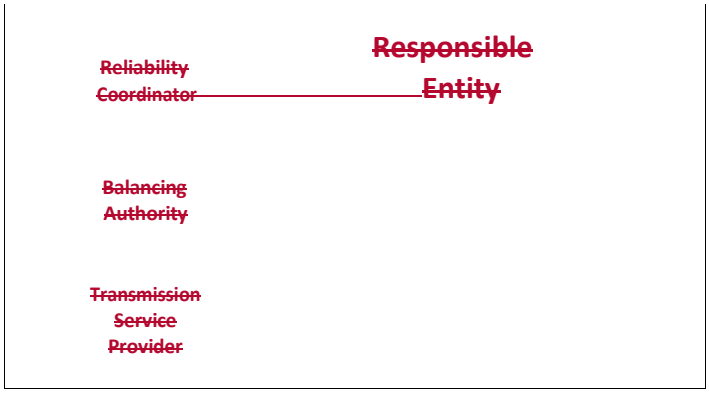


~~Figure 3 – Function and Functional Entity~~

~~Organizations, such as Regional Transmission Organizations or integrated utilities, may register with NERC as Responsible Entities by identifying which Functions they perform.~~

~~For example, as shown in Figure 4 an RTO (organization) may register with NERC to be a Reliability Coordinator, Balancing Authority, and a Transmission Service Provider. In this case we say that the RTO is the **Responsible Entity** for the Operating Reliability, Balancing, and Transmission Service Functions. We also use the expression that the RTO has "rolled up" these three Functions and is responsible for ensuring that the Tasks within each of those Functions are performed and all applicable standards requirements met.~~




~~Reliability Coordinator~~
~~Responsible Entity~~
~~Balancing Authority~~
~~Transmission Service Provider~~

~~**Figure 4 — Organizations may "roll up" more than one functional entity.**~~

Part 2 - Reliability Standards

The Functional Model describes the Standard Development Function and the Standards Developer functional entity and how these are related to Reliability Standards.

Reliability Standards can be developed at the North American level as well as at the regional level and can therefore be placed in two categories:

Reliability Standards Developed at the North American Level Within NERC

NERC, under regulatory authority, develops and maintains Reliability Standards using the NERC Reliability Standards Development Procedures. The standards are applicable across North America upon approval by governmental authorities, unless specifically stated otherwise within the standard, and enable NERC and Regional Entities to monitor and enforce compliance with the standards requirements.

NERC can use the Reliability Standards Development Procedures to approve a variance from a NERC Reliability Standard; the variance then becomes part of the standard. The three categories of variance are:

- Entity Variance that applies to an area less than a NERC Region
- Regional Variance that applies to a NERC Region but less than an Interconnection
- Regional Variance that applies to a NERC Region on an Interconnection-wide basis.

1. Reliability Standards Developed Within a Regional Entity

Regional Entities may develop and propose to NERC regional reliability standards that:

- Set more stringent reliability requirements than the NERC Reliability Standard
- Cover matters not covered by an existing NERC Reliability Standard.

Alternatively, NERC may direct Regional Entities to develop a regional reliability standard in order to implement a NERC Reliability Standard. Such a regional reliability standard, upon approval by NERC, becomes part of the NERC Reliability Standard.

Regional Entities must use a NERC-approved development process to develop these regional reliability standards. Such regional reliability standards, upon approval by NERC, become NERC Reliability Standards. As appropriate, NERC will approve the regional reliability standard as an:

- Interconnection-wide regional standard, or
- Non-Interconnection-wide regional standard.

Regional Criteria. Regional Entities may develop regional reliability criteria that are necessary to implement, to augment or to comply with Reliability Standards, or to address issues not within the scope of Reliability Standards. Such criteria are not approved by NERC and are not (NERC) Reliability Standards. As such, regional criteria, while clearly serving a reliability purpose, are best considered to be outside of the (NERC) Functional Model.

Part 13 - Market Operations (Resource Integration)

Market OpOperations is not a reliability Ffunction. NERC does not assign standards requirements to the Market Operator. Nevertheless, Mmarket Ooperations, a commercial or market function, is included in the Functional Model, in order to provide an interface point between reliability and commercial functions.

The role of the Mmarket Ooperator[5] also varies in design and responsibilities depending on whether resources are dispatched within a full-service market or where there is not a full-service market. However, , but all Mmarket Ooperators perform a resource integration task of one form or another under a resource integration protocol set of market rules that is are recognized by a state, federal, or provincial regulator. A resource integration protocol is the method used to determine the merit order of the generation to be dispatched. Generally, resource integration protocols are either cost-based or bid-based, depending on the market rules established by the regulatory authority. The basis and results for the resource integration algorithms are generally the same for cost-based and bid-based dispatch, which is why the Functional Model accommodates either type of protocol. Resource integration is discussed further in the following section II-4, Functional Model and Market Structures.

Multiple Balancing Authorities Within a Market Area. If the market area includes more than one Balancing Authority Area, then the market operator will also provide each Balancing Authority with the Net Interchange Schedule that results from the resource plan ("Resource Dispatch Interchange Schedule", or RDIS). Each Balancing Authority's RDIS will be an import or export to the Balancing Authority Area, and the sum of all RDISs within the market area must add to zero at each dispatch cycle.

Resource integration is discussed below for the cases of a full-service market and where there is no full-service market. Versions 4 and 5 of the Model refer to the entity as "Market Operator (Resource Integrator)", where Resource Integrator is seen as a better term than Market Operator in areas not having a full-service market. For simplicity, the discussion below uses only the term Market Operator, to apply even where there is not a full-service market.

1. The Market Operator in a Full-Service Market.

A full-service market is one which offers both the commercial services such as integrating resources ahead of Real-time and settlement after the completion of Implemented Interchange and dispatch cycles, and implement the resource plan in Real-time, making adjustment as necessary to meet other reliability requirements not envisaged during the resource integration process (for example, reliability constraints). In a full-service market, the Market Operator tasks involve integrating resources in accordance with established market rules. Following its market rules and using available market mechanisms, the Market Operator integrates market resources by establishing a generation dispatch plan to meet the load forecast for the upcoming dispatch cycle (typically five minutes or longer).

This generation dispatch plan is usually a function of the generators' incremental bids ("merit order"). The established generation dispatch plan is submitted to the Balancing Authority for implementation. When the plan is tested for implementation, and limitations caused by transmission congestion are identified, the Balancing Authority will adjust the dispatch schedules accordingly. This constitutes a "security-constrained" dispatch.

[5] For simplicity, only the term "market operator" is used; this is intended to apply even where there is not a full-service market.

Bid-Based Resource Integration. In those areas of North America having a full-service market, market protocols provide Generator Owners the ability to bid into the market. In those cases, Generator Owners will direct the submission of bids via the Generator Operators to the Market Operator. The Market Operator, in turn, provides the Balancing Authority with the generator dispatch plan, so that the generators within the market footprint would be instructed to operate at the same incremental bid. Transmission constraints may cause the actual dispatch to deviate from the dispatch plan. Re-dispatch methods used to relieve the congestion may use: direct resource assignments, area / zonal dispatch signals, or bus-signals. The zonal and bus methodologies are often referred to as "Locational Marginal Pricing," or LMP.

Relationship between the Market Operator and Balancing Authority. In a full-service market, there is a close relationship between the ~~M~~market ~~O~~operator and the Balancing Authority. A full-service ~~M~~market ~~O~~operator performs resource integration tasks and is assigned the tasks of:

- Determining the generation dispatch plan (unit commitment) ahead of time
- Integrating scheduled interchange into that generation plan
- Designating which generators are available for regulation service
- Providing the generation dispatch plan to the Balancing Authority ahead of ~~r~~Real-~~-~~time.

The Balancing Authority receives the plan, and implements it in real time.

2. The Market Operator Where There is not a Full-Service Market~~.~~

Cost-based Resource Integration. Where there is not a full-service market, the Market Operator will often be a traditional, vertically-integrated utility that acts also as Balancing Authority. The utility will dispatch its resources based on its incremental costs (fuel and operations and maintenance) and losses. The regulatory authority might specify the accounting rules for calculating these costs.
~~In jurisdictions not having a full-service market there will often be a traditional, vertically-integrated utility that may be both the Market Operator and the Balancing Authority, and most or all of the associated tasks will be performed internal to the utility. The generation dispatch plan will typically be cost-based, in contrast to bid-based dispatch in a full-service market.~~

In addition, there are jurisdictions that use a model other than full-service market and vertically-integrated utility, in particular bilateral Interchange Transactions. In this case, the organization serving as Balancing Authority will also be the ~~M~~market ~~O~~operator, operating on the basis of ~~n~~Net ~~i~~Interchange.

3. Summary: The Market Operator Using Different Structures

The table below describes how the current operating tasks may be performed by both the vertically-integrated utility and the unbundled, full-service market operator.

~~Part 4 - The Functional Model and Market Structures~~

~~This section explains how the Functional Model can accommodate different market structures by examining these structures from the perspective of resource integration protocol.~~

~~**Resource Integration Protocol**. A resource integration protocol is the method used to determine the merit order of the generation to be dispatched. Generally, resource integration protocols are either cost-based or bid-based, depending on the market rules established by the regulatory authority, as described in section II-3, Market Operations (Resource Integration). The basis and the results for the resource integration algorithms are generally the same for cost-based and bid-based dispatch, which is why the Functional Model can accommodate either type of protocol.~~

~~**Bid-Based Resource Integration**. In those areas of the U.S. and Canada having a full-service market, market protocols provide Generator Owners the ability to bid into the market. In those cases, Generator Owners will direct the submission of bids via the Generator Operators to the Market Operator. The market protocols are established by the governmental authority, such as the Federal Energy Regulatory Commission in the U.S. and provincial regulators in Canada. The Market Operator, in turn, provides the Balancing Authority with the generator dispatch plan, so that the generators within the market footprint would be instructed to operate at the same incremental bid. Transmission constraints may cause the actual dispatch to deviate from the dispatch plan. Re-dispatch methods used to relieve the congestion may use: direct resource assignments, area / zonal dispatch signals, or bus signals. The zonal and bus methodologies are often referred to as "Locational Marginal Pricing," or LMP.~~

~~**Cost-based Resource Integration**. Where there is not a full-service market, the Market Operator may be a traditional, vertically-integrated utility that acts also as Balancing Authority. The utility will dispatch its resources based on its incremental costs (fuel and operations and maintenance) and losses. The regulatory authority, such as the state public utility commission, might specify the accounting rules for calculating these costs.~~

~~**Multiple Balancing Authorities Within a Market Area.** If the Market Area includes more than one Balancing Authority Area, then the Market Operator will also provide each Balancing Authority with the net "interchange" schedule that results from the resource plan ("Resource Dispatch Interchange Schedule", or RDIS). Each Balancing Authority's RDIS will be an import or export to the Balancing Area, and the sum of all RDISs within the Market Area must add to zero at each dispatch cycle.~~

~~The table below describes how the current operating tasks may be performed by both the vertically-integrated utility and the unbundled, full-service market operator.~~

Task	No Full-Service Market: Vertically Integrated Structure	Full-Service Market: Unbundled Structure
Unit Commitment	Utility (performing as the Generator Owner) decides which units to run.	Generator Owners decides which units to make available.

Economic Dispatch	Utility (as Market Operator or Resource Integrator) performs economic dispatch calculation based on incremental costs or other requirements. Utility must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.	Market Operator collects bids from Generator Owners and develops integrated resource plans based on market rules (*e.g.*, bids). Market Operator must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.
Congestion Management	Results in different incremental costs ("lambdas").	Depending on the market structure, results in Different locational marginal prices (LMP), or Different marginal costs
Regulation Service	Utility (serving as the Balancing Authority, Load-Serving Entity, and Generator Owner) in concert with the Reliability Coordinator, determines the amount of regulation service required, and designates those units that provide the regulation service. Utility (as Balancing Authority) uses this information in its economic dispatch.	Balancing Authority, along with Reliability Coordinator, determines the amount of regulation service required. Generator Owners decide which units to bid in for regulation service. Market Operator runs bid pool for regulation service. Load-Serving Entity arranges for regulation services.
Generator Control	Utility (as Balancing Authority) pulses units that are designated by the Market Operator for regulation service. As regulating ability declines, the part of the utility that acts as Balancing Authority directs the part of the utility that acts as Market Operator to develop a new dispatch plan.	Balancing Authority pulses units that are designated by the Market Operator for meeting energy and regulation service requirements. As regulating ability declines, the Balancing Authority asks the Market Operator for a new dispatch plan.

Part 25 - Providing and Deploying Ancillary and Interconnected Operations Services~~Reliability-Related Services~~

The North American electric power system is transforming to a resource mix that relies less on coal and nuclear while integrating more natural gas, wind, solar, distributed generation, and demand response resources. Additionally, the power system will change further as micro-grids, smart networks, and other advancing technologies continue to be deployed. Recognizing that these changes represent a fundamental shift in the operational characteristics of the power system with potential reliability implications, the policies that govern Ancillary Services and the characteristics of Interconnected Operations Services may evolve to address these newer resources. Proper planning and providing system operators with the ability to manage resources in real time will be required to ensure that the appropriate levels of Interconnected Operations Services are available so that reliability is maintained as the resource mix evolves.

The Building Blocks of Reliability[6]

Based on the analysis of geographic areas that are experiencing the greatest level of change in their types of resources, a number of measures and industry practices are recommended to identify trends and prepare for the transition in resource mix. These recommendations consider both real-time operations and future planning to support frequency, ramping and voltage of the system.

Frequency – The electric grid is designed to operate at a frequency of 60 hertz (Hz). Deviations from 60 Hz can have destructive effects on generators, motors, and equipment of all sizes and types. It is critical to maintain and restore frequency after a disturbance such as the loss of generation. Frequency will immediately fall given such an event. This requires an instantaneous (inertial) response from some resources and a fast response from other resources to slow the rate of fall during the arresting period, a fast increase in power output during the rebound period to stabilize the frequency, and a more prolonged contribution of additional power to compensate for lost resources and bring system frequency back to the normal level.

Ramping – Adequate ramping capability (the ability to match load and generation at all times) is necessary to maintain system frequency. Changes to the generation mix or the system operator's ability to adjust resource output can impact the ability of the operator to keep the system in balance.

Voltage – Voltage must be controlled to protect system reliability and move power where it is needed in both normal operations and following a disturbance. Voltage issues tend to be local in nature, such as in sub-areas of the Transmission and distribution systems. Reactive power is needed to keep electricity flowing and maintain necessary voltage levels.

[6] Excerpt from North American Electric Reliability Corporation (NERC) ERS Framework Report, December 2015

Tariff Domain — Requirement for Ancillary Services. ~~The FERC open access (pro forma) tariff requires the (U.S.) Transmission Provider to provide the following Ancillary Services to all customers taking basic transmission service (Figure 5):~~

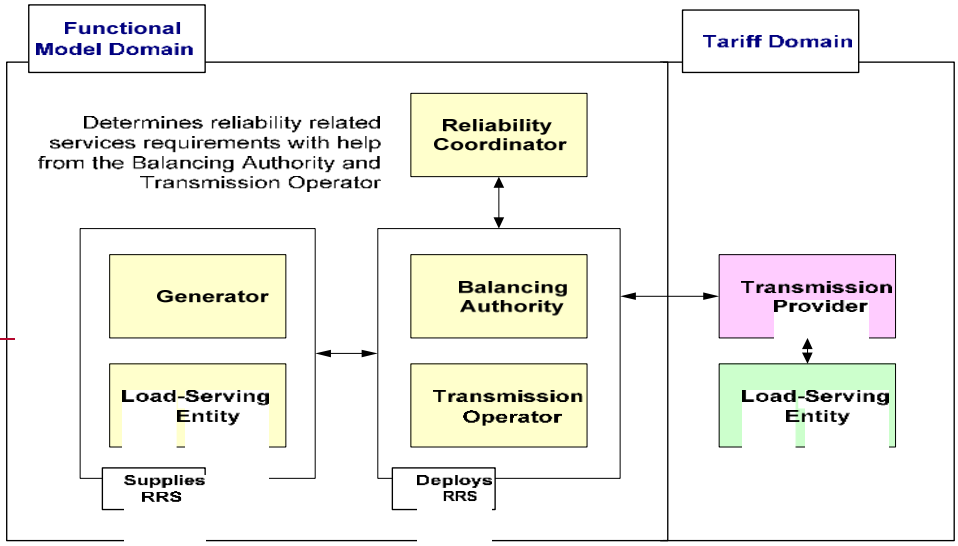


Figure 5 - Supply and Deployment of Ancillary Services and Reliability-Related Services.

The FERC pro-forma tariff requires that the Transmission Provider offer to provide Ancillary Services, as a provider of last resort, ~~the following services~~ to customers serving loads within the Transmission Provider's own area which do not purchase or self-provide:

1. Scheduling, system control, and dispatch
2. Reactive supply and voltage control from generation.
3. Energy imbalance
4. Regulation and frequency response
5. Operating reserve — spinning
6. Operating reserve — supplemental.
7. Generator Imbalance

Functional Model Domain — Interconnected Operations ~~Reliability-related~~ Services. A service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.[7] ~~The term "reliability-related services" means those services other than the supply of energy for load that are~~ These Interconnected Operations Services are physically provided by generators, transmitters and loads in order to maintain reliability.

~~Reliability-related services include voltage control and reactive power resources from generators, transmitters and loads.~~ Certain ~~t~~Transmission facilities can provide reactive support, but are not considered an Ancillary Service in the open access tariff, rather, they are considered part of basic ~~t~~Transmission service. In addition, loads may provide reserves through load-shedding or ~~d~~Demand-~~s~~Side ~~m~~Management, and may also provide frequency response.

Ancillary Services in the “tariff domain” could be served by Interconnected Operations Services ~~reliability-related services~~ in the "reliability domain.” The Functional Model explains that the Balancing Authority, alone or

[7] Definition of Interconnected Operations Services from the NERC Glossary of Terms (as of May 15, 2016).

in coordination with the Reliability Coordinator, determines the amount required and arranges for Interconnected Operations Services ~~reliability-related services~~ to ensure balance:

- The Balancing Authority determines regulation, load following, frequency response, ramping capability and contingency reserves, ~~etc.,~~ and deploys these as Interconnected Operations Services~~reliability-related services~~.
- The Transmission Operator determines the reactive resources ~~reliability-related services~~ necessary to meet its ~~r~~Reactive ~~p~~Power requirements to maintain ~~t~~Transmission voltage within operating limits, and deploys these as its set of Interconnected Operations Services~~reliability-related services~~.
- The Reliability Coordinator, working with the Transmission Operator, determines the need for black start~~Black Start~~ capacity. The Transmission Operator cannot do this alone, because it may not have a wide enough picture of the ~~t~~Transmission system.

~~Through its Reliability Standards, NERC holds organizations (those registered as Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Service Providers) responsible to comply with applicable standards requirements, including those requirements that depend on reliability-related services.~~ The quantity of and processes used to deploy those Interconnected Operations Services ~~reliability-related services~~ depend on the ~~R~~regional and local system characteristics and regulatory requirements. The responsible organizations establish the quality and quantity of their own Interconnected Operations Services ~~reliability-related services~~, using these processes and procedures in a manner that ensures reliable operation of the BES~~compliance with the standards' requirements~~.

~~Part 6 - Managing Bilateral Interchange Transactions – Basic Concepts~~

~~Interchange that crosses multiple Balancing Authority (BA) Areas can be broken down daisy-chain fashion into individual Balancing Authority to Balancing Authority Interchange Transactions, with the Sink Balancing Authority designated as the "manager" (the "Tag Authority").~~

~~The Functional Model recognizes this Interchange process as the current Industry practice and includes BA to BA "after hour" checkout for net Interchange between adjacent Balancing Authorities. Also, the Interchange Coordinator function "coordinates" and "communicates Interchange ("deals") that is ready for physical implementation between Balancing Authorities. The IC receives approvals that recognize ramping capability. The IC also communicates the individual Interchange information to all involved parties (Figure 6).~~

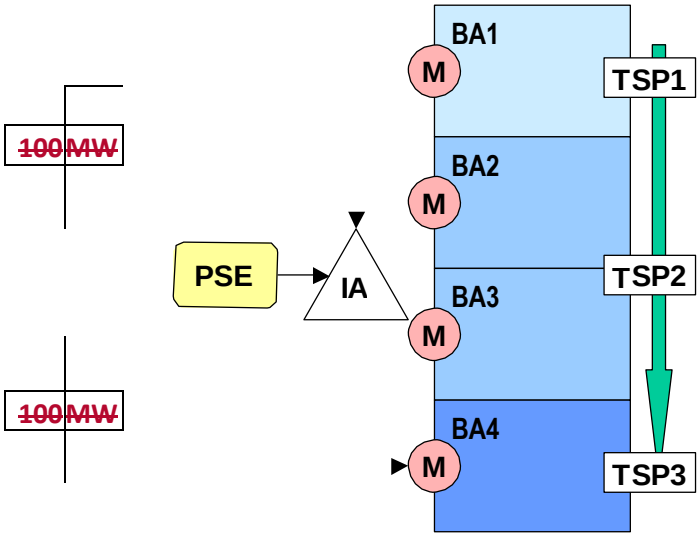


Figure 6 — The Interchange Coordinator manages transactions between the source and sink Balancing Authorities.

Managing Bilateral Interchange Transactions — Allowable Concept

The Functional Model does not prevent Balancing Authorities from scheduling Interchange with Interchange Coordinators. The ICs would ensure that the Arranged Interchange is balanced (equal and opposite) between the Source and Sink BAs. In the example in Figure 6, the IC manages a transaction from BA1 to BA4. The schedule is

BA1 → IA → BA4

and the transmission service path is

TSP1 → TSP2 → TSP3.

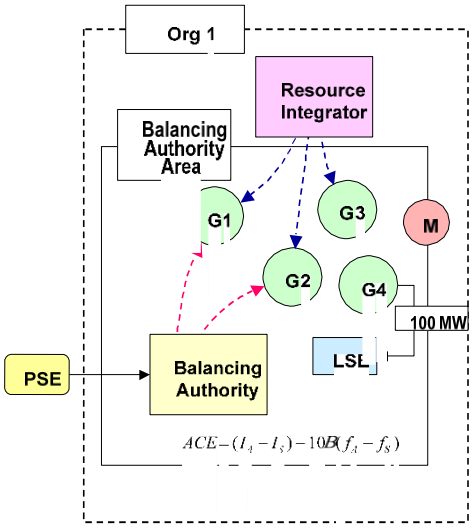


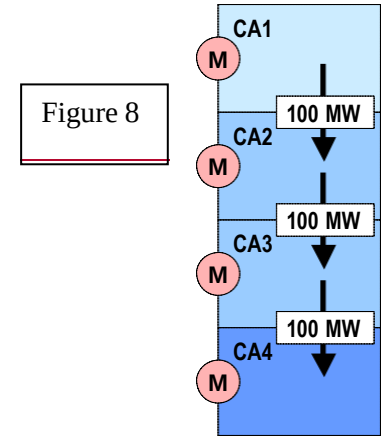
Figure 7 – The Purchasing-Selling Entity submits the bilatera transaction to the Balancing Authority for intra-BA transactions.

~~**Interchange Transactions within a Balancing Authority Area.** A bilateral Interchange within a Balancing Authority Area does not require Interchange Coordinator authorization. In the example in Figures 8 and 9, the Purchasing-Selling Entity submits the 100 MW request for Interchange to the Balancing Authority who will inform the Resource Integrator (or Market Operator) if the Resource Integrator needs to know which generators are committed to the Interchange, and to the Reliability Coordinator for reliability assessment.~~

~~The tables on the following page compare the Interchange checkout procedures that the Balancing Authorities use today with the procedures that the Balancing Authorities would use if this type of Interchange concept were applied.~~

Checkout under Existing NERC Practice Figure 8			
Control Area	**Actual from Tie Meters**	**Schedule with CA**	**Inadvertent**
CA1	+100 to CA2	+100 to CA2	0
CA2	-100 from CA1 +100 to CA3	-100 from CA1 +100 to CA3	0
CA3	-100 from CA2 +100 to CA4	-100 from CA2 +100 to CA4	0
CA4	-100 from CA3	-100 from CA3	0
Potential Future Checkout Figure 9			
Balancing Authority	**Actual from Tie Meters**	**Schedule with IC**	**Inadvertent**
BA1	+100 to BA2	+100 to IC	0
BA2	-100 from BA1 +100 to BA3	0	0
BA3	-100 from BA2 +100 to BA4	0	0
BA4	-100 from BA3	-100 from IC	0

Figure 8



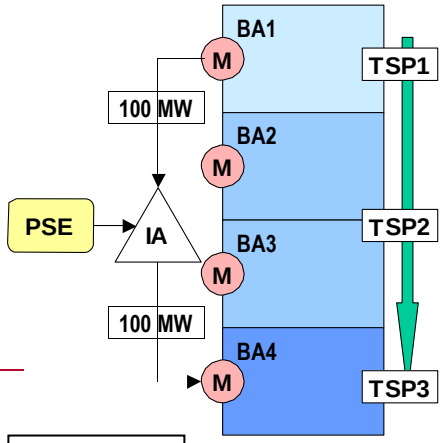


Figure 9

Part 7 - Managing Bilateral Interchange – Scheduling Agents

Some Transmission Providers provide a Scheduling Agent service for their Balancing Authority members. The Scheduling Agent provides a single point of contact for all Interchange into or out of those Balancing Authorities. For example, the Southwest Power Pool serves as a Scheduling Agent for its members, and any Balancing Authority external to SPP will schedule to any SPP Balancing Authority by way of the SPP as the Scheduling Agent. This simplifies Interchange scheduling for parties both internal and external to SPP.

In the example in Figure 10, two Interchange Coordinators arrange a total of 225 MW with the Scheduling Agent for a group of four Balancing Authorities as follows:

IS1 = 100 MW into BA1 IS3

= 50 MW into BA3 IS4 = 75

MW into BA4 IS2 = 0

The Scheduling Agent must ensure that the sum of the Interchange from all Interchange Coordinators is exactly equal to the sum of the Interchange from the Scheduling Agent to its Balancing Authorities:

ISA1 + ISA2 = IS1 + IS2 + IS3 + IS4

$I_{S1} + I_{S2} + I_{S3} + I_{S4} = 225$ MW

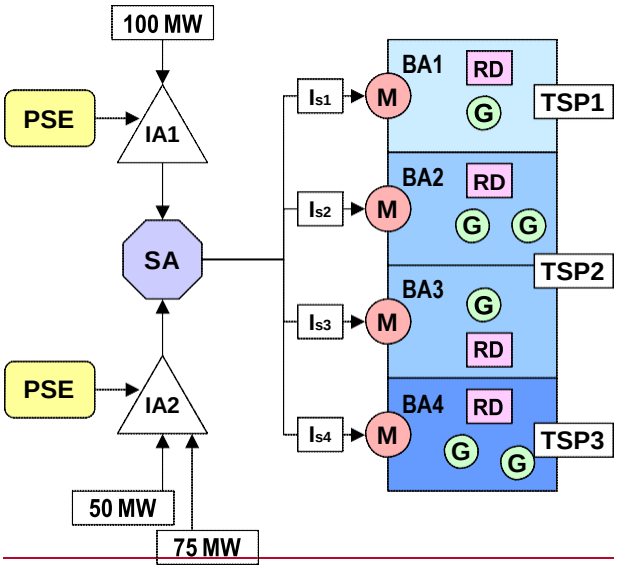


Figure 10 - The Scheduling Agent divides a 100 MW transaction among a group of Balancing Authorities.

If the Balancing Authority(ies) use a Scheduling Agent, then the Interchange Coordinator will request approvals from the Scheduling Agent — not the Balancing Authority(ies) — during the Interchange authorization process. The Interchange Coordinator will also notify the Scheduling Agent of any Interchange curtailments.

Because Interchange scheduling is an integral function of the Balancing Authority, the Functional Model Working Group defines that the Scheduling Agent is actually an agent of the Balancing Authorities. The Balancing Authorities would still be the Responsible Entities for ensuring that the Interchange from the Scheduling Agent was incorporated into the BAs' energy management systems. Some have argued that the Scheduling Agent would need to be certified and monitored to ensure that it handled the Interchange properly.

~~Part 8 – Non-coincident Resource Integrator and Balancing Authority Areas~~

~~**Bilaterals between Market Areas.** In the examples above, each Balancing Authority Area was the same as the Market or Resource Integrator Area. When generation is dispatched (either cost-based or bid-based) over several Balancing Authority Areas, we may be faced with a bilateral Interchange whose source or sink is the entire Market Area, and cannot be identified with any particular Balancing Authority within that area. In this situation, the Interchange Coordinator interfaces with the Scheduling Agent for the Market Area. Then the Scheduling Agent, working with the Market Operator will determine how the bilateral Interchange is allocated among the Balancing Authority Areas.~~

~~As was explained in the technical discussion on reliability related services, the Scheduling Agent ensures that the RDIS are properly allocated to the Balancing Authorities.~~

~~Now we can combine the Scheduling Agent's management of RDIS with bilateral Interchange Transactions as shown in Figure 11.~~

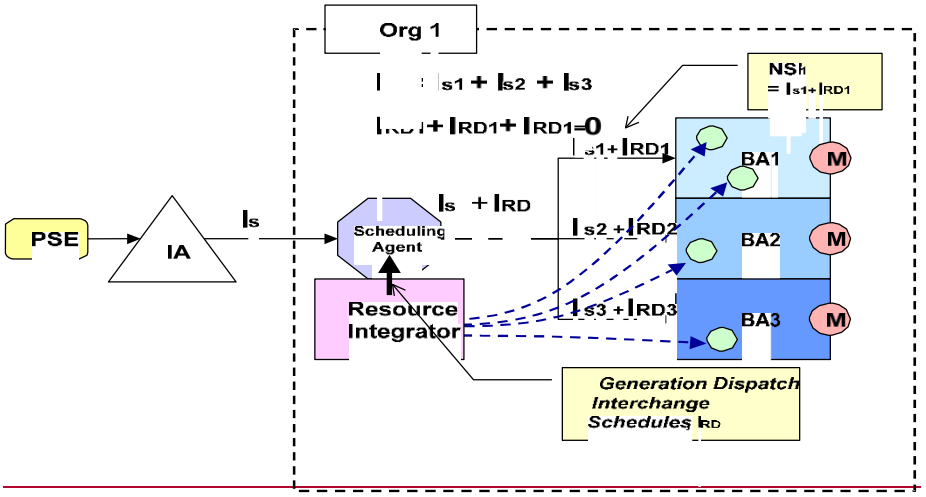
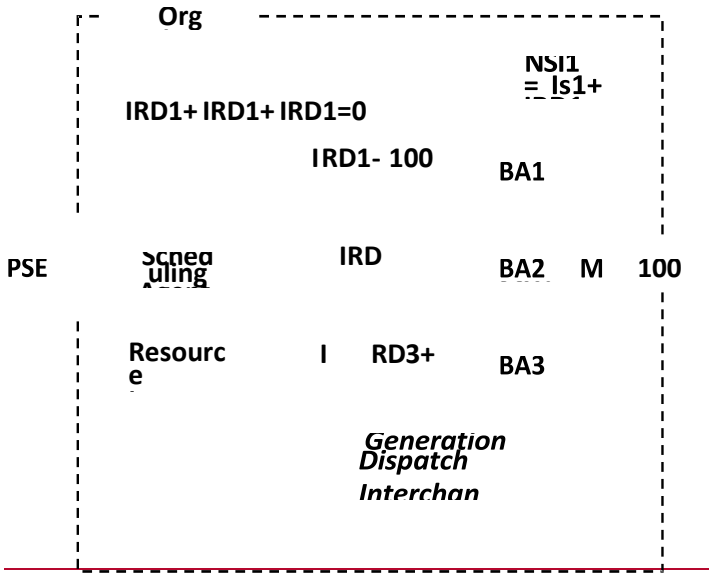


Figure 11 - The Scheduling Agent manages bilateral Interchange Transactions in to or out of the Market Area ~~as well as the Interchange Schedules that result from the~~ economic dispatch or market operations.

~~**Bilaterals between Balancing Authorities within the same Market Area**. Bilateral Interchange between two Balancing Authorities within the same Market Area does not require Interchange Coordinator management because the Market Area is under a common tariff, and the Market Operator would have a close relationship with the Reliability Coordinator. In the example in Figure 12 the Purchasing Selling Entity has submitted a 100 MW request for Interchange from BA1 to BA3 directly to the Scheduling Agent, who would then coordinate the transaction between the source and sink Balancing Authorities. The Scheduling Agent then submits the resulting interchange schedule to the Source and Sink Balancing Authorities, and informs the Market Operator if the Market Operator needs to know which generators are committed to the transaction.~~



~~*Figure 12 - The PSE submits its Interchange Transaction information directly to the Scheduling Agent when the bilateral transaction is within the same Market Area.*~~

Part 39 – Implementing Interchange Coordination

Requests for Interchange (RFI) are initiated by entities (Purchasing-Selling Entities, Load-Serving Entities, or Generator Owners) who have arranged for Interchange and contracted for Transmission Service from a Transmission Service Provider. The RFIs are submitted to a (Tag) agent service who confirms all information needed and electronically sends Tags to the authority service, or the Interchange Coordinator. The Interchange Coordinator IC Ttasks are being performed by the organization functional entities registered as Balancing Authorities (BAs), specifically the Sink Balancing Authority"sink BA"[8] for a particular interchange transaction. A Sink Balancing Authority is defined as, "[the Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule."[9] It has been noted that the Functional Model could in principle have assigned the IC Tasks to the BA and avoided the need for a separate Interchange function. This approach was not followed because it was envisioned in the future that the IC Tasks could be performed by entities other than a BA, a possibility that is allowed for by defining the IC separate from the BA. Therefore, the Functional Model *accommodates* the sink BA as the IC, but does not *require* it.

The implementation of the IC extends also to the NERC INT standards that exist today, which impose data collecting and interchange-information distribution requirements on an IC.

The NERC direction regarding registering of ICs is compatible with the approach taken in the Model:

- There is a need for a separate Interchange Coordinator functional entity
- Allowance is made for BAs to register as ICs, but organizations that are not BAs are not precluded from doing so.
- The IC is an entity, not a software tool.

The remainder of this section clarifies the context and need for an Interchange Coordinator from the perspective of the Model, by describing the associated reliability tasks and their implications. As such, it may be of use to those involved in registration processes.

INTERCHANGE PRACTICE

Background

To help ensure reliability, "requests" for iInterchange tTransactions (Arranged Interchange) must be approved before that request is allowed to become an "iImplemented" Iinterchange transaction (or Confirmed Interchange). Without approvals, it is possible that the sum of all iInterchange sSchedules in an interconnection will not sum to zero. That, in turn, would lead to the condition that even if every Balancing Authority were controlling to zero Area Control Error, there could still be off-generation occurring because of the Net Interchange sSchedule being in error.

Historically, approvals were handled on a control area to control area basis. Net iInterchange sSchedules between neighbors were checked and approved prior to implementation. Only if there were disagreements did individual requests get checked. This pragmatic practice served the industry well — but not perfectly. When given control areas did not take the time to compute their own Net Schedule interchange (and instead merely accepted the numbers from its individual neighbors) — what can and did happen was that individual

[8] That is, the BA in whose area the bilateral interchange transaction terminates.

[9] Definition of Sink Balancing Authority from the NERC Glossary of Terms (as of Mary 15, 2016).

schedules were active on one side of the control area, but not on the other side. Not until serious operational symptoms arose (*e.g.*, unexplained parallel flows, or unusual number of time error corrections) was there an investigation.

Current Practice

The ~~Functional Model's~~ inclusion of an Interchange Coordinator in the Functional Model recognizes a reliability concern regarding responsibility for approving a ~~r~~Request for ~~i~~Interchange, and the distribution of the information for the approved request for ~~i~~Interchange. Each and every Interchange ~~t~~Transaction that a Purchasing-Selling Entity~~SE~~ desires to implement must have approvals from all parties involved, and must have approval by each of them regarding the characteristics of each of those Interchange ~~t~~Transactions.

Today, the approval and communication are implemented in a two-step process — each step focusing on different quantities. One step focuses on the individual Interchange ~~t~~Transactions and their respective characteristics. This step is carried out by a tagging authority, which is the Interchange Coordinator. In order to obtain approval or denial, the Interchange Coordinator sends the Request for Interchange electronically, as Arranged Interchange, to the (tag) approval service provider for the Balancing Authorities, Transmission Service Providers, Load-Serving Entities, Purchasing-Selling Entities, and Generator Owners. After obtaining approval or denial, the approval service then sends the decision to the Interchange Coordinator. If all parties approve the Interchange Transaction, the Arranged Interchange becomes Confirmed Interchange. The Interchange Coordinator then informs all parties of this status.

The other step focuses on implementing Net Interchange ~~s~~Schedules (*i.e.*, the net of the ~~t~~Transactions that were approved). This step is carried out by neighboring Balancing Authorities~~As~~. The Sink Balancing Authority is responsible for ensuring the process is properly carried out. ~~This two-step process can and does work. The problem is that when there is a breakdown in the process, there is no compliance process in place.~~

~~For example, if the tagging authority were the root cause of non-compliance (such as a computer error) that caused transaction information to elude analysis of a participant in the transaction, and that error resulted in a blackout, then no one would be held non-compliant, if no entity is registered as IC for the transaction. If a BAleft accepts a Net Schedule from BAcenter but the transactions within that Net do not agree with the complementary transactions of the accepted Net Schedule between BAcenter and BAright, then again no one can be held non-compliant if no one is registered as IC.~~

~~What is in place t~~Today ~~is~~ the NAESB ~~NERC~~ Tagging Specification is in place. ~~,~~ Under the NAESB Tagging Specification, ~~under which~~ each ~~s~~Sink Balancing Authority is responsible for providing ~~T~~ttagging ~~S~~sservices, either directly or by arranging with a third party to provide this service as its agent.[10] ~~However, the Tagging Specification is not a standard and therefore not a sufficient basis for compliance enforcement.~~

~~An important question for many within industry is "how do you implement the concept of an Interchange Coordinator (IC)".~~

~~The initial step of the implementation requirements has been met with the NERC Board adoption of the Version 1 Interchange standards, which contain concepts and functions of the IA (now referred to as the IC). The Electronic Tagging Function Specification assigns the Tag Authority requirements to the entity responsible for Balancing Authority operations (*i.e.*, Sink BA).~~

[10] See, NAESB Electronic Tagging Functional Specification, version 1.8.0, approved November 7, 2007. Click here: http://reg.tsin.com/Tagging/e-tag/e-tag-spec-v-18-20071107.doc

~~To implement this concept, the Electronic Tagging Functional Specification (E-tag Spec.) was revised to map the Tagging Service requirement from the Balancing Authority to the entity performing the Interchange function for the Sink Balancing Authority's organization (still allows the Sink BA to use third party to fulfill the tasks of the requirements).~~

Part ~~10~~ 4 - ~~Distribution Provider as Load-Serving Entity~~ Risk-Based Registration

In support of its mission to assure the reliability of the Bulk Power System, NERC has transformed its approach to compliance and enforcement to be forward-looking with a focus on high reliability risk areas. The purpose of the NERC Risk-Based Registration (RBR) initiative was to ensure that the right entities are subject to the right set of applicable Reliability Standards, using a consistent approach to risk assessment and registration. In December 2014, NERC submitted a petition for approval of proposed revisions to the NERC Rules of Procedure (ROP), seeking to implement the changes sought as a result of the RBR initiative.[11] Specifically, NERC requested major reforms to the registration process, including the elimination of the Purchasing-Selling Entity (PSE), Interchange Authority (IA), and Load-Serving Entity (LSE) functional registration categories; modifications to the thresholds for registering entities as Distribution Providers (DP); and procedural improvements to the registration process. The procedural improvements to the registration process included: (1) the establishment of a materiality test for registration, with clear procedures and criteria for evaluation of whether an entity has a material impact on reliability with respect to above-the-line and below-the-line Registry Criteria determinations; (2) an enhanced process for review by a NERC-led, multi-regional panel of certain registration, deactivation and deregistration decisions, as well as certain requests for sub-set lists of Reliability Standards; (3) development of a common registration form to facilitate uniformity in Regional Entity collection of the information from registration candidates; and (4) one-time attestations that allow entities to record that a specific Reliability Standard requirement is "Not Applicable." On March 19, 2015, the Commission issued an order largely approving proposed revisions to the NERC ROP.[12]

As outlined in the RBR petition, the ERO compliance program and stakeholders benefit from the proposed revisions as they appropriately focus resources on entities with the greater potential impact on reliability. The RBR reforms were based on the February 2011 Commission technical conference in Docket No. AD11-6-000 on *Priorities for Addressing Risks to the Reliability of the Bulk-Power System*, where there was a recognition that "if everything is a priority, then nothing is a priority."[13] Priorities must be driven by a clear understanding of risks and consequences, and the costs and benefits associated with addressing them. With a shift toward risk-based approaches and a learning industry, NERC introduced quantitative measures of reliability performance. The revisions were a result of NERC taking a risk-based approach to reliability and to incorporating lessons-learned through continuously improving and adapting operations.

Even though the three entities (PSE, IA, and LSE) were removed from the NERC Registry Criteria, these entities–as users, owners and operators of the Bulk Power System–remain within in the statutory scope of both FERC and NERC pursuant to Section 215 of the Federal Power Act. Functionally, Load-Serving Entities, Purchasing-Selling Entities and Interchange Authorities continue to exist and continue to perform in the markets or operate under open access transmission tariffs, as applicable. The revisions did not alter the NERC registered ballot body (codified in Appendix 3D of the NERC Rules of Procedure).

~~FERC Order of October 16, 2008 approved a NERC filing that proposed, as a short-term solution, revisions to the NERC Statement of Compliance Registry Criteria (Registry Criteria) to provide that a distribution provider to~~

[11] See, Petition of the North American Electric Reliability Corporation for Approval of Risk-Based Registration Initiative Rules of Procedure Revisions, Docket No. RR15-4-000 (2014).

[12] North American Electric Reliability Corporation, 150 FERC ¶ 61,213 (2015).

[13] Additional information available on FERC website: http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=5561&CalType=%20&CalendarID=116&Date=02/08/2011&View=Listview.

whose system the electric loads in retail choice areas are connected will be registered as the LSE for all loads connected to its system.[14]

The Order requires that "the Distribution Provider to whose system the electric loads in retail choice areas are connected are to be registered as the LSE for all loads connected to its system for the purpose of compliance with NERC's approved reliability standards applicable to LSEs."

NERC states that, with respect to load served by retail choice through load aggregators, there may not be a clear agreement in place between the distribution providers and the load aggregators delineating the responsibilities between the parties regarding compliance with mandatory Reliability Standards. Further, the compliance filing explains that "NERC will exercise its discretion in the application of penalties or sanctions upon Distribution Providers who are providing this information on the behalf of loads served by a retail choice load aggregator until such time as both entities are either registered or the standards are updated to clarify the responsibilities for each party as ultimately identified in the longer term solution proposed by NERC."

NERC stated that DPs have both the infrastructure and access to information to enable them to comply with the Reliability Standards that apply to LSEs. Moreover, distribution providers provide the wires over which the load of retail power marketers is served. NERC also pointed out that, with regard to distribution providers that provide wires service for retail power marketers, these DPs were LSEs for that load prior to state retail access programs. In many instances, these distribution providers remain providers of last resort and must plan their system taking into consideration all load served over their wires, including retail access load.

The Order also provides that a distribution provider will not be registered based on the above criterion if it has transferred responsibility to another entity (that is appropriately registered) by written agreement.

NERC also stated that this approach ensures that all loads are represented in the planning and operation of the Bulk Power System by the entity with the best information regarding those loads.

The scope of the review leading to Version 5 of the Functional Model included consideration of whether changes should be made in the Model to accommodate these changes to the Registry Criteria.

Version 5 does *not* contain changes to reflect these changes to the Registry Criteria, as follows:

- the problem and its solution relate to registration, not the Tasks performed, and as such do not directly affect the Model; this is in keeping with the approach used for the Joint Registration Organization, which is defined for compliance purposes and not in the Model
- the present solution is a short-term one, with the longer-term solution yet to be defined.

[14] This section contains extracts from the order, which may be found at http://www.nerc.com/files/Statement_Compliance_Registry_Criteria_V5-0.pdf

Part 11 – Terminology Changes in Version 5

Version 5 contains terminology changes intended to improve consistency between the Model and the NERC Glossary, the Rules of Procedure (ROP) and Reliability Standards.[15] Inconsistency has potential for creating needless complexity, confusion and wasted effort for those who use NERC documents. The changes are of three types:

- Entity terminology
- Entity names
- Entity definitions. Entity terminology

The term "responsible entity" in the Model has been changed to "functional entity".[16]

- The usage of "responsible" in Version 4 derived from an earlier version of the Model. Version 4 clarified that the Model is limited to describing the performance of tasks, but not compliance aspects such as responsibility for such performance. Version 5 takes this clarification one step further by replacing the term "responsible" in the Model.
- The Model uses the term functional entity to apply to a *class of entity*, such as a Balancing Authority, and makes no reference to the *specific organizations* that register as functional entities. Consistency within NERC documents would be improved if conforming changes were made to the NERC Rules of Procedure and Glossary of Terms to consistently use the term "functional entity" when the reference is to the *class of entity* (*e.g.*, BA), and use the terms "responsible entity" and "registered entity" when the reference is to a *specific organization* regarding its responsibility or registration, respectively.[17]

Entity names

- The functional entity name Interchange Authority has been changed to Interchange Coordinator
  - The term "coordinator" better reflects the nature of the function.
  - A conforming change would be required in the Glossary (which also uses Interchange Authority)
- Conforming changes would be required in other NERC documents.

Entity definitions

- The Model has been revised to define the various functional entities, not the Functions as at present, consistent with the approach used in the Glossary and standards.
- The functional entity definitions have been revised.
  - The form of the definitions is uniform, with each definition beginning: "The functional entity …"
  - Each definition is single sentence, limited to a simple statement of the nature of the tasks performed. As a result some of the current descriptive wording in Version 4 or Glossary definitions has been removed in the Version 5 definitions.

[15] Full alignment will require conforming changes in Reliability Standards, the Glossary and ROP. These changes are seen as editorial that is, not representing changes to essential content.

[16] Version 4 actually uses "Responsible Entity". Because the Glossary and ROP generally use "responsible entity", *i.e.*, all lower case, this usage has been adopted for version 5 of the Model.

[17] These changes in terminology are intended to address confusion between the entity described in the Model and specific organizations, which has been a frequently expressed concern of stakeholders.

The following table gives the Version 4 definitions, the Glossary definitions (April 20, 2009), and the Version 5 definitions (recommended for use in the Glossary.

Functional Entity Definitions:

Model Version 4, NERC Glossary and Model Version 5

VERSION 4[18]	GLOSSARY[19]	VERSION 5[20]	COMMENT
Balancing Authority	**Balancing Authority**	**Balancing Authority**	
Integrates resource plans ahead of time, and maintains load-interchange- generation balance within a Balancing Authority Area and supports Interconnection frequency in real time.	The responsible entity that integrates resource ahead of time, maintains load- interchange-generation balance within a Balancing Authority Area, and supports Interconnection	The functional entity that integrates resource plans ahead of time, maintains generation-load-interchange balance within a Balancing Authority Area, and contributes to Interconnection frequency	Minor Glossary change needed.
Compliance Enforcement Authority	**Compliance Monitor**	**Compliance Enforcement Authority**	
Monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards.	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.	The functional entity that monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-	Glossary needs to be updated
Distribution Provider	**Distribution Provider**	**Distribution Provider**	

[18] For simplicity of presentation, the definitions indicated for the Model in Version 4 are assigned to the functional entity, not the function. For example, the Model has a definition for the Standards Development function, but the definition is shown below as applying to the Standards Developer *functional entity*.

[19] Glossary version of February 12, 2008. See link at http://www.nerc.com/files/Glossary_12Feb08.pdf

[20] These definitions would replace existing definitions in the Glossary (but entities not currently defined in the Glossary would not be added).

VERSION 4	GLOSSARY	VERSION 5	COMMENT
Provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.	The functional entity that provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.	Glossary change needed – descriptive detail removed. Revised version would be essentially that of Version 4 of the Model.
Generator Operator	**Generator Operator**	**Generator Operator**	
Operates generating unit(s) to provide real and reactive power.	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.	The functional entity that operates generating unit(s) and performs the functions of supplying energy and reliability-related services.	Minor Glossary change needed.
Generator Owner	**Generator Owner**	**Generator Owner**	
Owns and provides for maintenance of generating facilities.	Entity that owns and maintains generating units.	The functional entity that owns and maintains generating	Minor Glossary change needed.
Interchange Coordinator	**Interchange Authority**	**Interchange Coordinator**	
Ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Arranged Interchange between Balancing Authority Areas.	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.	The functional entity that ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Confirmed Interchange between Balancing Authority Areas.	Glossary changed needed. Revised version would be essentially that of Version 4 of the Model.
Load-Serving Entity	**Load-Serving Entity**	**Load-Serving Entity**	

~~Secures capacity, energy and transmission services (including necessary reliability-related services) to serve the End-use Customer.~~	~~Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of~~	~~The functional entity that secures energy and transmission services (and reliability-related services) to serve the electrical demand and energy~~	~~Minor Glossary change needed.~~

VERSION 4	GLOSSARY	VERSION 5	COMMENT
	its end-use customers.	requirements of its end-use customers.	
Market Operator (Resource Integrator)	[not defined]	**Market Operator (Resource Integrator)**	
The Market Operations function, its tasks, and the interrelationships with other entities are included in the Functional Model only as an interface point of reliability Functions with		The market entity whose interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.	Term not used in Reliability Standards and therefore is not required in the Glossary..
Purchasing Selling Entity	**Purchasing Selling Entity**	**Purchasing Selling Entity**	
Purchases or sells energy, capacity, and necessary reliability-related services as required.	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.	The functional entity that purchases or sells, and takes title to, energy, capacity, and reliability related services.	Glossary change needed – descriptive detail removed.
Planning Coordinator	**Planning Authority / Coordinator**	**Planning Coordinator**	
Ensures a plan (generally one year and beyond) is available for adequate resources and transmission within a Planning Coordinator area. It integrates and evaluates the plans from the Transmission Planners and Resource Planners within the Planning Coordinator area to ensure those plans	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.	The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas	Minor Glossary changed needed.
Reliability Assurer	[not defined]	**Reliability Assurer**	

Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to		The functional entity that monitors and evaluates the activities related to planning and operations, and coordinates activities of	Term not used in Reliability Standards and therefore is not required in the Glossary.

VERSION 4	GLOSSARY	VERSION 5	COMMENT
secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.		functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer Area and adjacent areas.	
Reliability Coordinator	**Reliability Coordinator**	**Reliability Coordinator**	
Ensures the real-time operating reliability of the bulk power system within a Reliability Coordinator Area.	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.	The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.	Glossary changed – descriptive detail removed. Revised version would be essentially that of Version 4 of the Model.

Resource Planner	**Resource Planner**	**Resource Planner**	
Develops a plan (generally one year and beyond) within its portion of a Planning Coordinator area for the resource adequacy of its specific loads (End-use Customer demand and energy requirements) within a reliability area.	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy [of] specific loads (customer demand and energy requirements) within a Planning Authority Area.	The functional entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Resource Planner area.	Minor Glossary change needed.
Standards Developer	[not defined]	**Standards Developer**	

VERSION 4	GLOSSARY	VERSION 5	COMMENT
Develops and maintains Reliability Standards to ensure the reliability of the bulk power system.		The functional entity that develops and maintains Reliability Standards to ensure the reliability of the Bulk Electric System.	Term not used in Reliability Standards and therefore is not required in the Glossary.
Transmission Operator	**Transmission Operator**	**Transmission Operator**	
Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.	The functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area.	Glossary changed needed. Revised version would be essentially that of Version 4 of the Model.
Transmission Owner	**Transmission Owner**	**Transmission Owner**	
Owns and provides for the maintenance of transmission facilities.	The entity that owns and maintains transmission facilities.	The functional entity that owns and maintains transmission facilities.	Minor Glossary change needed.

~~Transmission Planner~~	~~Transmission Planner~~	~~Transmission Planner~~	
~~Develops a plan (generally one year and beyond) for the reliability of the interconnected bulk power system within the Transmission Planner Area. Ensures that the plan integrates resources and transmission within its area as well as coordinating with the plans from adjacent and overlapping Transmission Planners and Resource Planners. The Transmission Planner also ensures that the plan meets the Reliability Standards.~~	~~The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.~~	~~The functional entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a Transmission Planner Area.~~	~~Minor Glossary change needed.~~
~~Transmission Service Provider~~	~~Transmission Service Provider~~	~~Transmission Service Provider~~	
~~Administers the transmission tariff and provides transmission services under applicable transmission service agreements (for example, the pro forma tariff).~~	~~The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.~~	~~The functional entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.~~	~~Minor Glossary change needed.~~

Part 512 - ~~Reliability~~ Areas and Boundaries

~~**Assets versus Geography as the Basis for Defining Areas and Boundaries**~~

~~It is useful for organizations that are functional entities to specify an associated Area, which defines the portion of the Bulk Electric System within which their functional entity status applies. Moreover, by reviewing all of the Areas for a particular functional entity, it is possible to establish whether there are overlapping responsibilities or gaps, which can then be eliminated. The concept of Areas and boundaries (the interfaces between adjacent Areas) is therefore important in establishing clear responsibilities for compliance with Reliability Standards.~~

The ~~Functional Model~~ building block for defining boundaries and ~~A~~areas for the functional entities that operate and plan the Bulk Electric System is electrical, namely the individual Bulk Electric System asset. That is, the building blocks are the individual ~~t~~Transmission, generation and customer equipment assets that collectively constitute the Bulk Electric System. This enables any given Bulk Electric System asset to be associated with at least one ~~single organization, with respect to any particular~~ functional entity. This will ~~therefore~~ provide the basis for clear assignment of responsibility for managing the potential reliability impacts of the asset~~., where the specific responsibility is to be established in NERC's registration, certification and compliance processes.~~

~~It is noted that a~~ A geographic definition is not ~~adequate~~ appropriate in a situation where there are, for example, two Transmission Operators in a given geographic footprint, differentiated by the voltage level of the assets under their respective control. In such a situation, the use of the specific Bulk Electric System assets provides an adequate basis for defining Areas/boundaries.

The following areas and boundaries are essential for understanding how to reliably operate and plan for a particular BES asset:

1. **Reliability Coordinator Area**: The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
2. **Balancing Authority Area**: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
3. **Transmission Operator Area**: The collection of Transmission assets over which the Transmission Operator is responsible for operating.

~~1.~~4. **Transmission Planner area**: The collection of Transmission assets over which the Transmission Planner is responsible for planning.

~~2.~~5. **Planning Coordinator area**: The collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning. Its area includes one or more Transmission Planner Areas.

~~NERC Rules of Procedure specify area relationships among functional entities, excerpted as follows:~~

~~2.2 Regional entities shall verify that all balancing authorities and transmission operators are under the responsibility of one and only one reliability coordinator.~~

~~2.3 Regional entities shall verify that all transmission elements of the bulk power system operated within their geographic boundaries are under the authority and control of one and only one transmission planner, planning authority, transmission owner, and transmission operator.~~

~~2.4 Regional entities shall verify that all loads and generation sources within their geographic boundaries are under the authority and control of one and only one balancing authority.~~

~~2.5 Regional entities shall verify that no geographical or electrical areas of the bulk power system within their boundaries have duplication of coverage or are lacking an entity to perform required duties and tasks as identified in the reliability standards.~~

~~Size Considerations Relating to Area~~

~~The Functional Model does not specify a minimum or maximum size for a reliability area. From the perspective of the Model, an organization qualifies to be the Responsible Entity for a particular Function by virtue of performing the Function's Tasks.~~

~~Size is not a consideration in the distinction between local-area versus wide-area reliability. Local-area reliability is the responsibility of the Transmission Operator in the sense of considerations relating to the Transmission Operator's local system or area, regardless of how large that area may be. Similarly, wide-area reliability is the responsibility of the Reliability Coordinator in the sense of considerations relating as well to the systems and areas of neighboring Reliability Coordinators, regardless of how small the Reliability Coordinator's own area may be.~~

~~Part 13 – Generating versus Transmission Assets~~

~~The Model does not attempt to define the boundary between generating and transmission facilities, in particular regarding facilities such as protective relays and lines that are within or in proximity to a generating plant perimeter. Such boundaries may be defined by NERC, Regional Entities or governmental authorities.~~

~~From the perspective of the Model, for a facility that is determined to be a generating facility, its owner will be a Generator Owner, and its operator a Generator Operator. Correspondingly, for a facility that is determined to be a transmission facility, its owner will be a Transmission Owner, and its operator a Transmission Operator.~~

~~It is recognized that an owner may not be the operator of its facility, as a result of delegating the operating of the facility to another party through an agreement, and that in all cases it is NERC's registration process, not the Model that determines assignment as a functional entity.~~

~~Part 14 – Roles in Load Curtailment~~

~~This section discusses the roles of the various functional entities that may be involved in load curtailment. These entities include: Reliability Coordinator, Balancing Authority, Transmission Operator, Distribution Provider and Load-Serving Entity.~~

~~Types of Load Curtailment~~

~~There are two general types of load curtailment — voluntary and non-voluntary.~~

~~A. Voluntary Load Curtailment~~

~~Voluntary load curtailments are usually arranged ahead of real time under some form of agreements — market price trigger, compensation, etc., or on a totally voluntary basis with or without any compensation. Implementation of voluntary load curtailment is intended to provide a relief to the market price in some established markets, or a relief to system demand to aid the Balancing Authority in a tight capacity/energy situation, or a relief to loading on a Distribution Provider system.~~

~~Voluntary load curtailment based on pricing structure need not be requested since it is governed by pre-arranged agreement and mechanism. Voluntary curtailments that have not been pre-arranged may need to be communicated. Since end-use customers are involved in the decision-making process and must respond to the request, and the Load-Serving Entity holds the contractual obligation to serve these customers, such requests are usually communicated to the end-use customers through the Load-Serving Entity as directed by the initiating entities, which include the Balancing Authority and the Distribution Provider, to address potential capacity/energy shortfall in the Balancing Authority area or potential overload on the Distribution Provider system.~~

~~B. Non-Voluntary Load Curtailment (Shedding)~~

~~Non-voluntary load curtailments are usually implemented in real time to address imminent or existing capacity/energy shortfalls or transmission reliability concerns such as exceedance of an IROL or SOL, or a low voltage problem. Some pre-arrangements may be made ahead of time such as identifying the amount and location of load to be shed, and specific critical loads that may be excluded from curtailment by feeder configuration. However, since implementation is often of urgent nature, a decision process involving the end-use customers and communication via the Load-Serving Entity is usually bypassed.~~

~~Depending on the need to implement this type of curtailment, load is either curtailed automatically (such as in the case of underfrequency or undervoltage load shedding), or a curtailment directive is made by the Reliability Coordinator, Balancing Authority, or Transmission Operator directly to the Distribution Provider for physical implementation (except when this can be accomplished directly by the Transmission Operator). The Distribution Provider may also have a need to curtail load to address overload problems on its system. In this case, the Distribution Provider may implement load shedding directly.~~

Role of Responsible Entities in Load Curtailment Reliability

Coordinator

The Reliability Coordinator maintains Real-time system reliability, which includes implementing a number of emergency actions which include directing load shedding to preserve system reliability. In addition, the Reliability Coordinator, in collaboration with the Balancing Authority and Transmission Operator, may also participate in invoking public appeals, voltage reductions, demand-side management, and even load shedding if the Balancing Authority cannot achieve resource-demand balance.

When a Reliability Coordinator has a need to direct non-voluntary load curtailment, it issues a directive to the Distribution Provider or the Transmission Operator to implement the curtailment.

Balancing Authority

When a Balancing Authority anticipates or experiences a capacity or energy shortfall, it will take actions such as public appeals, demand-side management programs, and load curtailment, as necessary to maintain a resource/demand/interchange balance. As time permits, the Balancing Authority may seek voluntary load curtailment to reduce demand in its area. In this case, the Balancing Authority will communicate such a request to the Load-Serving Entity. In the event of an Energy Emergency, the Balancing Authority may direct non-voluntary load curtailment by issuing a directive to the Distribution Provider or the Transmission Operator for implementation.

Transmission Operator

The Transmission Operator, in coordination with the Reliability Coordinator, can take actions such as implementing voltage reductions and implement load shedding to mitigate a transmission emergency. When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedance of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.

Distribution Provider

The Distribution Provider provides the facilities that could be used to shed load for emergency action. It is that entity that has the capability to physically shed load, but it is generally not responsible for directing load shedding. Loading shedding is generally directed by the Reliability Coordinator, Balancing Authority and Transmission Operator.

However, the Distribution Provide may itself initiate voluntary and non-voluntary load curtailments for its own reasons, for example to reduce its area's demand or to mitigate overload on its system. When a Distribution Provider sees a need for voluntary load curtailment, it directs the Load-Serving Entity to communicate a request for curtailment to the end-use customers.

When it sees a need to implement non-voluntary load curtailment to address a loading or voltage concern, it implements the curtailment on its own.

Load-Serving Entity

The Load-Serving Entity identifies the loads for voluntary as well as non-voluntary curtailments. For voluntary load shedding, the LSE is responsible for making contractual arrangements with end-use customers who participate in such a program, and identifying to the Balancing Authorities and Distribution Providers of such arrangements so

~~that these customers, once committed, would be put on curtailment list if and when needed to address potential capacity shortage and/or system constraints.~~

~~For voluntary load curtailment that has not been pre-arranged, the Load-Serving Entity may be directed by the Balancing Authority or Distribution Provider to communicate its curtailment requests to the end-use customers.~~

~~For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.~~

~~Once identified and necessary contractual arrangements are made, the Distribution Provider (or the Transmission Operator as appropriate) will make reasonable efforts to arrange (feeder) connection arrangement such that these critical loads will not be curtailed by the load shedding facilities until other options have been exhausted.~~

~~The Load-Serving Entity is responsible for communicating requests for voluntary curtailment to the appropriate end-use customers, thereby increasing the effectiveness of voluntary load curtailment. In some jurisdictions, it appears that the "wires" entity, *i.e.*, the Distribution Provider, that performs these Tasks. However, from a functional model viewpoint, it is the Load- Serving Entity function within that Distribution Provider organization that performs this task.~~

Part 15 – History of Revisions

Version 1

Version 1 of the Model was approved in February 2002.

Version 2

Version 2 of the Model was approved Feb. 10, 2004.[21]

Version 2 responded to confusion between a Function and the organization responsibility for its performance, by separately identifying the Responsible Entity associated with each Function. For example, whereas Version 1 used the single term Transmission Operator for both the Function and responsible entity, Version 2 introduced Transmission Operations as the Function (the Tasks), and Transmission Operator as the Responsible Entity for those Tasks. Corresponding changes were made for all Functions. This distinction has been maintained in subsequent versions.

The Market Operation Function and Market Operator were added to the Model to provide an interface point with commercial functions.

Version 1 contained only operating Functions. Version 2 introduced three planning Functions (Planning Reliability, Transmission Planning, Resource Planning) and three associated Responsible Entities (Planning Authority, Transmission Planner and Resource Planner).

Version 3

Version 3 of the Model was approved February 13, 2007.[22] It addressed a number of issues that arose as NERC transitioned to new, mandatory and enforceable reliability standards. Several of these issues were outlined in a final report issued by the Functional Model-Reliability Standards Coordination Task Force (FMRSCTF) in March 2005.[23] The FMRSCTF was established to ensure alignment between the Model and the new NERC standards being developed.

The changes introduced in Version 3 included:

- The Reliability Authority entity name was changed to Reliability Coordinator, for consistency with terminology used in reliability standards.
- Changes were made to more clearly define the Transmission Operations Tasks and the relationship of the Transmission Operator with the Reliability Coordinator
- Changes were made to the Interchange Coordinator to accommodate the practice of Balancing Authority-to-Balancing Authority interchange scheduling
- The Planning Authority was renamed the Planning Coordinator
- The Regional Reliability Assurance Function and the Regional Reliability Organization Responsible Entity were added.
- It was clarified that "area" of responsibility for a particular Responsible Entity's applied to the collection of Bulk Electric System assets associated with the entity, that is, that area was defined electrically, not

[21] See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Functional_Model_Version_2.pdf.
[22] See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Function_Model_Version3_Board_Approved_13Feb07.pdf.
[23] Final Report of the Functional Model — Reliability Standards Coordination Task Force ("FMRSCTF"), approved March 11, 2005. See ftp://www.nerc.com/pub/sys/all_updl/sac/fmrsctf/FMRSC_TF_Report_3-11-05.pdf.

geographically.

Version 4

Version 4 included the following changes from Version 3:

- The names Regional Reliability Assurance / Regional Reliability Organization were changed to Reliability Assurance / Reliability Assurer.

  The name changes reflect the view that reliability assurance could be performed on other than a regional basis. Moreover, the functional entity need not be a Regional Entity.

- The names Compliance Monitoring / Compliance Monitor were changed to Compliance Enforcement / Compliance Enforcement Authority.

  The changes were judged to better reflect the strong role of compliance in the ERO regime.

- The wording was changed in a number of instances to ensure that the Model's Tasks and relationships between Responsible Entities do not specify prescriptive requirements. Prescriptive requirements are specified in reliability standards and NERC processes, not in the Model.

- For example, references in Version 2 that a Responsible Entity "must ensure" or "is required to ensure" were changed in Version 4 to simply "ensures".

- It was clarified that the Generator Owner and Transmission Owner *provide for the maintenance* of their respective assets.

  This recognizes that the performance of the maintenance may be assigned by the owner to another party, for example, to a Generator Operator or Transmission Operator, respectively.

Version 5

Version 5 introduces the following changes:

Entity name

- Interchange Authority has been changed to Interchange Coordinator. Also incorporated are the terms Arranged and Confirmed Interchange to be consistent with terminology used in the INT standards.

Terminology

The term "responsible entity" in the Model has been changed to "functional entity".

- The usage of "responsible" in Version 4 derived from an earlier version of the Model. Version 4 clarified that the Model is limited to describing the performance of tasks, but not compliance aspects such as responsibility for such performance. Version 5 takes this clarification one step further by replacing the term "responsible" in the Model.

- The Model uses the term functional entity to apply to a *class of entity*, such as a Balancing Authority, and makes no reference to the *specific organizations* that register as functional entities.
- Reliability is best served if there is consistency of definitions within all NERC documents. These documents include, but are not limited to, the Functional Model, the NERC Rules of Procedure and Glossary of Terms.

Entity definitions

- The Model has been revised to define the various *functional entities*, not the *functions*, consistent with the approach used in the Glossary and standards.
- The functional entity definitions have been revised.

- ~~The form of the definitions is uniform, with each definition beginning: "The functional entity that…"~~
- ~~Each definition is single sentence, limited to a simple statement of the nature of the tasks performed. As a result some of the current descriptive wording in Version 4 or Glossary definitions has been removed in the Version 5 definitions.~~

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Functional Model

~~Function Definitions and Functional Entities~~

Version 6~~5~~

Prepared by the Functional Model Advisory Group
Approved by the Standards Committee: [Month, Year]

RELIABILITY | ACCOUNTABILITY






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DRAFT

Section I: Purpose of the Functional Model~~Part 1: Foreword~~

The functional model (FM) is a guideline that identifies the functions that must be performed to ensure that the Bulk Power System is planned and operated in a reliable manner. The FM describes, in general terms, the functions that must be performed to ensure reliability, the specific tasks that are necessary to perform each function, and the relationships between functional entities that perform the various tasks. In its capacity of a guideline, the FM serves to provide a framework for NERC Reliability Standards as they are developed through the standard development process. The FM is independent of any particular organizational or market structure. The focus of the FM is solely on identification of reliability-related functions and the associated tasks and relationships.

Equally important to explaining what the FM does do, is a clear explanation of what the FM does **not** do. The FM is **not** a mandatory and enforceable document. The FM is **not** a "standard" and does not have compliance effects. If there is a conflict between the FM and Reliability Standards, the Reliability Standards always take precedence. The FM is only a guideline serving to provide details on how the different functions work together to ensure the reliability of our BPS. Also, the FM is **not** intended to identify the entities responsible for NERC registration. The NERC registration process is undertaken by NERC (and the Regional Entities) pursuant to authority from FERC, ultimately derived from the Federal Power Act. The FM has no authority, ability, or intent to impact or influence the NERC Registration process. Below is an overview of the NERC Registration process, which is completely separate from, and should not be confused with, the FM guideline. Similar to conflicts with Reliability Standards, if the FM and NERC Registration do not align, NERC Registration takes precedence.

~~This document replaces version 4 of the NERC Reliability Functional Model that the NERC Standing Committees approved in September 2008.~~

~~Historically, Control Areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and provide for their customers' electricity needs. The traditional Control Area operator balanced its load with its generation, implemented Interchange Schedules with other Control Areas, and ensured transmission reliability.~~

~~As utilities began to provide transmission service to other entities, the Control Area also began to perform the function of Transmission Service Provider through tariffs or other arrangements. NERC's Operating Policies reflected this traditional electric utility industry structure, and ascribed virtually every reliability function to the Control Area.~~

~~Beginning in the early 1990s with the advent of open transmission access and restructuring of the electric utility industry to facilitate the operation of wholesale power markets, the functions performed by Control Areas began to change to reflect the newly emerging industry structure. These changes occurred because:~~

1. ~~Some utilities were separating their transmission from their merchant functions (functional unbundling), and even selling off their generation;~~
2. ~~Some states and provinces were instituting "customer choice" options for selecting energy providers; and,~~
3. ~~The developing power markets were requiring wide-area transmission reliability assessment and dispatch solutions, which were beyond the capability of many Control Areas to perform.~~

~~As a result, the NERC Operating Policies in place at that time, which centered on Control Area operations, were beginning to lose their focus, and become more difficult to apply and enforce.~~

~~The NERC Operating Committee formed the Control Area Criteria Task Force (CACTF) in 1999 to address this problem. The task force began by listing all the tasks required for maintaining electric system reliability and then~~

~~organizing these tasks into basic groups that it called "functions." Ultimately, the Task Force decided to build a "Functional Model." This involved breaking down the previous reliability functions more finely, such that all organizations involved in ensuring reliability —whether they are traditional, vertically integrated control areas, regional transmission organizations, independent system operators, independent transmission companies or so on— can identify those functions they perform, and register with NERC as one or more of the functional entities. Initially the Model dealt with operating functions, but it was subsequently expanded in Version 2 to incorporate planning-related functions. This Functional Model framework provides guidance to NERC standards drafting teams to write reliability standards in terms of the functional entities who perform the reliability functions.~~

~~Adapted from Version 2 of the NERC Functional Model, February 10, 2004.~~

Section II: Overview of the NERC Registration Process~~Part 2: Introduction~~

The NERC Registration process consists of several elements, including the NERC Registry Criteria and the NERC Compliance Registry, and involves both the Regional Entities and NERC. The process for registration is described in the NERC Rules of Procedure, Section 500 (Appendix 5A: Organization Registration and Certification Manual and Appendix 5B: Statement of Compliance Registry Criteria).

The starting point for the NERC program for monitoring and enforcing compliance with FERC-approved Reliability Standards is the process for comprehensively identifying and registering owners, operators, and users of the Bulk Power System that are responsible for performing reliability-related functions in accordance with the approved Reliability Standards.[1] The NERC Registry Criteria provides for Bulk Power System users, owners and operators that perform a function identified in Section II of the Registry Criteria, and have a material impact on Bulk Power System reliability (which is generally determined by whether they meet the threshold criteria in Section III of the Registry Criteria) to register as one or more of fifteen functions. NERC and the Regional Entities identify such entities, which are then obligated to comply with Commission-approved Reliability Standards.[2] Identified entities are registered and included on the NERC Compliance Registry.[3] The NERC Compliance Registry identifies the reliability functions that each registered entity is responsible for meeting pursuant to the requirements of Reliability Standards. Organizations listed in the NERC Compliance Registry are responsible for knowing the contents of, and complying with, Reliability Standards applicable to the reliability function(s).[4] The registration criteria for the reliability functions are specified in the NERC Statement of Compliance Registry Criteria.[5]

The potential costs and effort of registering every organization potentially within the scope of "owner, operator, and user of the BPS," while ignoring their impact upon reliability, would be disproportionate to the improvement in reliability that would reasonably be anticipated from doing so. Therefore, the two stated goals for registration are: (1) consistency between and among Regional Entities and across the continent in the application of the criteria for registering entities; and (2) registration of any entity whose facilities or operations are deemed material to the reliability of the Bulk Power System, irrespective of other considerations.[6]

~~The NERC Reliability Functional Model provides the framework for the development and applicability of NERC's Reliability Standards as follows:~~

- ~~The Model describes a set of Functions that are performed to ensure the reliability of the Bulk Electric System. Each Function consists of a set of related reliability Tasks. The Model assigns each Function to~~

[1] *See*, Order on Electric Reliability Organization Risk Based Registration Initiative and Requiring Compliance Filing, Docket No. RR15-4-000, 150 ¶ 61,213 (March 15, 2015).

[2] Section 215(b)(2) of the Federal Power Act (FPA) requires all users, owners and operators of the Bulk Power System to comply with Reliability Standards approved by the Commission. Similarly, the Commission's regulations at 18 C.F.R. §39.2 and §40.2 require all users, owners, and operators of the Bulk-Power System to comply with applicable Reliability Standards and applicable rules of the ERO and Regional Entities approved by the Commission.

[3] NERC Statement of Compliance Registry Criteria (Registry Criteria) at 2 ("Organizations will be responsible to register and to comply with approved Reliability Standards to the extent that they are owners, operators, and users of the Bulk Power System, perform a function listed in the functional types identified in Section II of this document, and are material to the Reliable Operation of the interconnected Bulk Power System as defined by the criteria and notes set forth in this document.").

[4] *See*, NERC Rules of Procedure §501. The current categories of reliability functional entities are listed in Rules of Procedure Appendix 5B, Statement of Compliance Registry Criteria.

[5] *See*, NERC Rules of Procedure, Appendix 5B.

[6] *See*, NERC Rules of Procedure, Appendix 5B at 4.

a functional entity, that is, the entity that performs the function. The Model also describes the interrelationships between that functional entity and other functional entities (that perform other Functions).

- NERC's Standards Development Teams develop Reliability Standards that assign each reliability requirement within a standard to a functional entity (that is defined in the Model and NERC's Glossary). This is possible because a given standard requirement will typically be related to a Task within a Function. A standard requirement will be very specific, whereas a Task in the Model will be more general in nature.
- NERC's compliance processes require specific organizations to register as the entities responsible for complying with standards requirements assigned to the applicable entities.
- The Model's Functions and functional entities also provide for consistency and compatibility among different Reliability Standards.

The Model is a guideline for the development of standards and their applicability. The Model it is not a Standard and does not have compliance requirements. Standards developers are not required to include all tasks envisioned in the model, nor are the developers precluded from developing Reliability Standards that address functions not described in the model. Where conflicts or inconsistency exist, the Reliability Standards requirements take precedence over the Model.

The Model is independent of any particular organization or market structure. An organization may perform more than one Function.

The Functional Model describes a functional entity envisioned to ensure that all of the Tasks related to its Function are performed. The Model, while using the term "functional entity", is a guideline and cannot prescribe responsibility. It is NERC's compliance processes, backed by regulatory authority, that specify the manner in which, a functional entity is "legally responsible" for meeting the standards requirements assigned to that functional entity.

The work performed to meet the requirements may be self-performed or performed by others.

Functional Model maintenance. The Functional Model is maintained by the Functional Model Working Group (FMWG) under the direction of the NERC Standards Committee, with technical content in the Model and accompanying technical document approved by the Standing Committees (OC, PC and CIPC).

Technical discussions. The companion document, "Functional Model – Technical Discussions," provides additional details on the Functions themselves, how organizations can "roll up" those Functions they wish to perform, and how organizations as "functional entities" interrelate.

The following terms are used in the Functional Model and do not appear in the NERC Glossary.

Functional Entity. The term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function.

Function. A set of related reliability Tasks.

Task. One of the elements that make up a Function in the Functional Model.

Customer. The term applies to a customer for transmission, capacity or energy services (a Purchasing-

Selling Entity, Generator Owner, Load-Serving Entity, or End-use Customer).

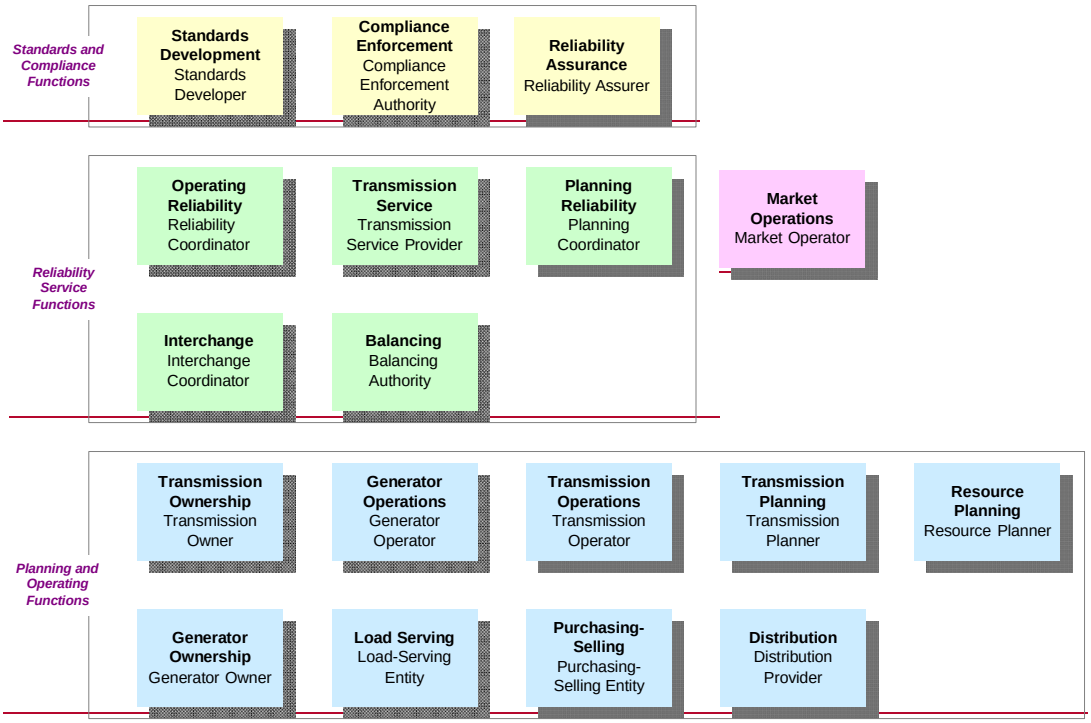
End-use Customer. The party served by a Load-Serving Entity (energy) and Distribution Provider (wire service).

Purpose of the Functional Model

The purpose of the NERC Reliability Functional Model is to:

1. Provide a framework for Reliability Standards developed through the NERC standards development process that will apply to certain Tasks defined in the Functional Model.
2. Describe in general terms each Function and the relationships between the entities that are responsible for performing the Tasks within the Functions. The framework for developing the Function definitions is:
   a. The Functions are independent of the organization structure performing the functions, and
   b. The Functions provide flexibility to accommodate the range of presently conceivable organization structures, as well as accommodate alternative tools, procedures and processes.

~~Functional Model Diagram~~



~~Function Name~~	~~Functional Entity~~
~~Balancing~~	~~Balancing Authority~~
~~Compliance Enforcement~~	~~Compliance Enforcement Authority~~
~~Distribution~~	~~Distribution Provider~~
~~Generator Operations~~	~~Generator Operator~~
~~Generator Ownership~~	~~Generator Owner~~
~~Interchange~~	~~Interchange Coordinator~~
~~Load-Serving~~	~~Load-Serving Entity~~
~~Market Operations~~	~~Market Operator (Resource Integrator)~~
~~Operating Reliability~~	~~Reliability Coordinator~~
~~Planning Reliability~~	~~Planning Coordinator~~
~~Purchasing-Selling~~	~~Purchasing-Selling Entity~~
~~Reliability Assurance~~	~~Reliability Assurer~~
~~Resource Planning~~	~~Resource Planner~~
~~Standards Development~~	~~Standards Developer~~
~~Transmission Operations~~	~~Transmission Operator~~
~~Transmission Ownership~~	~~Transmission Owner~~
~~Transmission Planning~~	~~Transmission Planner~~
~~Transmission Service~~	~~Transmission Service Provider~~

Guiding Principles of the Functional Model

As explained in the Introduction, the Model provides the framework on which the NERC Reliability Standards are developed and applied. To ensure that this framework remains viable, the Model itself is governed by a set of "guiding principles" that define a Function's Tasks and establish the relationships between the functional entities which are responsible for meeting the requirements in the NERC Reliability Standards that correspond to these Tasks. These principles serve as a guideline to those revising or interpreting the Model.

For further details, refer to the Technical Discussions section in the Functional Model Technical Document.

0. The Model must be *complete*, that is, it must include all reliability Tasks and interrelationships between entities performing them. This helps ensure that any reliability requirement arising in a Reliability Standard will generally be related to a Task in the Model and therefore be assignable to a particular functional entity.

0. The Model must group these Tasks into a set of Functions, such that:

    - There are enough Functions (and corresponding functional entities) to accommodate the full range of organization structures and responsibilities within the industry, and

    - The number of Functions is developed based on logical grouping of the Tasks and kept low as reasonably possible.

        - In particular, where a number of organizations that perform a given Function form a single group, the Model recognizes this as a business arrangement among organizations, not a new Function and corresponding new functional entity. That is, the fundamental reliability Tasks, and hence the Function, remain the same – all that has changed is *how* the Function is performed. Examples of such groups are a reserve sharing group (a collection of entities that are Balancing Authorities), or a planned resource sharing group.

0. The Model is structured to ensure there are no gaps or overlaps in the performance of operation Tasks in the operating timeframe anywhere in the Bulk Electric System. This is achieved in part by associating an "area" of purview for each functional entity. Areas are defined in term of the individual transmission, generator and customer equipment assets that collectively constitute the Bulk Electric System. For example, each Bulk Electric System asset has one Reliability Coordinator, one Balancing Authority, and one Transmission Operator. Regarding overlaps for planning, as described in the Technical Document, it is not always possible to achieve this in the case of planning Functions, where there may be overlapping levels of responsibility for given assets. Questions regarding relationships between the areas of different functional entities, such as whether one type of area must be totally within another type of area, will be defined in Reliability Standards or the Rules of Procedure, not the Model.

0. Tasks describe *what* is to be done, not *how* it is to be done.

0. The Model is a guideline that describes reliability Tasks and interrelationships between the entities that perform them – it is not prescriptive. In particular, the Model does not address requirements for registering or becoming certified as a functional entity, or the delegation or splitting of responsibility for meeting standards requirements.

~~Clarification Service~~

~~The Functional Model is a reference tool that links functional entities with associated reliability- related functions and respective Tasks. Drafting teams use the Functional Model to help them determine which functional entity should be required to comply with each requirement in a reliability standard.~~

~~From time to time questions of clarification and interpretation arise. The FMWG is following the process described below for handling requests for clarification of the Functional Model. This process, which has been approved by the Standards Committee, is accessible to all drafting teams as well as any other interested stakeholders. If a drafting team needs help in understanding Tasks that make up a Function and/or in determining which functional entities should be responsible for particular standards requirements, the drafting team's coordinator will send an e-mail to the NERC Staff assigned as the FMWG facilitator with a request for clarification.~~

0. ~~The NERC Staff assigned as the FMWG facilitator will convene a conference call/meeting of available members of the FMWG to review the question(s) and provide a clarification.~~
    - ~~If the question(s) need more detailed discussion with the drafting team, the two coordinators will organize a conference call/meeting with available members of the FMWG and available members of the drafting team to discuss the issues in more detail.~~
0. ~~Each FMWG request for clarification and the associated response will be posted on the NERC Functional Model Web Page under a Frequently Asked Questions section.~~
    - ~~If the questions result in changes to the model, the changes will be added to a change summary table used to develop the next updated version of the Functional Model document.~~

Section III: ~~Part 3:~~ Functions and Functional Entities

This section defines the reliability-related functions and functional entities that perform the associated ~~T~~tasks that are necessary to plan and operate the Bulk Electric System in a reliable manner. This section also identifies the relationships between various functional entities that are formed in order to perform the reliability-related tasks. ~~characterizes the functional entities that perform these Tasks, and provides examples of the inter-relationships that take place between entities to ensure reliability. As standards are developed, the Model may be revised to add and remove Tasks under specific Functions to aid in the development of standards. Relationships between functional entities in the Model are reciprocal. Where~~ In some instances, a one-to-one relationship may exist~~s~~ between two functional entities; in other instances, there may be ~~, the Model will include the reciprocal relationship specifically; and where~~ a one-to-many relationship. ~~exists, the reciprocal relationships are implied.~~

~~Functional Model Diagram~~

~~Standards Development and Standards Developer~~

~~Standards Development~~

~~Tasks~~

~~0. Develop and maintain a standards development process.~~

~~0. Develop Reliability Standards for the planning and operation of the Bulk Electric System.~~

~~Standards Developer~~

~~Definition~~

~~The functional entity that develops and maintains Reliability Standards to ensure the reliability of the Bulk Electric System.~~

~~Introduction to the Standards Developer~~

~~The Model addresses Reliability Standards created at NERC using the NERC Reliability Standards Development Procedure and Regional Standards that are created through an open Regional process and approved by NERC for enforcement. The Functional Model is intended to serve as the framework for the development and application of these Reliability Standards.[7]~~

~~Relationships with Other Functional Entities~~

- ~~0. Receives request for Reliability Standards through the public process.~~
- ~~0. Sends Reliability Standards to the Compliance Enforcement Authority.~~

~~[7] There are also Regional Criteria that are requirements that Regions create and enforce, that are not included in the Model.~~

~~Compliance Enforcement and Compliance Enforcement Authority~~

~~Compliance Enforcement~~

~~Tasks~~

~~0. Develop, maintain and implement a compliance enforcement process.~~

~~0. Evaluate and document compliance.~~

~~Compliance Enforcement Authority~~

~~Definition~~

~~The functional entity that monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards.~~

~~Relationships with Other Functional Entities~~

~~2. Receives Reliability Standards from the Standards Developer.~~

~~3.~~**1.** ~~Administers the compliance enforcement process for all functional entities as required by Reliability Standards.~~

Reliability Assurance and Reliability Assurer

Reliability Assurance

Tasks

1. Develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable the Reliability Assurer 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.
2. Develop and implement a compliance 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 the Reliability Assurer has been given enforcement authority.
3. Develop and maintain a program for identifying and registering those entities that are responsible for compliance with the governmental-approved Reliability Standards.
4. Provide for certification of all entities with primary reliability responsibilities requiring certification.
5. Provide a mechanism to ensure system operators are provided the education and training necessary to obtain the essential knowledge and skills and are therefore qualified to operate the BES.
6. Provide reliability readiness evaluation and improvement, and formation of sector forums if necessary for reliability.
7. Develop a reliability assessment and performance analysis program that conducts reviews and assessments of the overall reliability of the interconnected BPS, including:
    - 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.
    - 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.
    - Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.
    - Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.
    - 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.
8. Provide leadership, coordination, technical expertise, and assistance to the industry in responding to a major event.
9. Provide the education and training necessary for Bulk Power System personnel and regulators to obtain the essential knowledge necessary to understand and operate the BES.
10. Through the use of appropriate functional entities 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.

11. 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.

~~1. Coordinate reliability assurance among adjacent Reliability Assurers through the development of necessary protocols and processes.~~

~~1. Coordinate the activities related to maintaining critical infrastructure protection.~~

~~1. Establish reliability assurance processes and documentation related to planning and operations within the Reliability Assurer's area including such things as a regional reliability plan or a Reliability Coordinator plan.~~

~~1. Identify and address gaps in reliability processes and responsibilities.~~

Reliability Assurer

Definition

Subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada, assure the reliability of the Bulk Power System in North America by developing and enforcing Reliability Standards; annually assessing seasonal and long-term reliability; monitoring the Bulk Power System through system awareness; and, educating, training, and certifying industry personnel. ~~The functional entity that monitors and evaluates the activities related to planning and operations, and coordinates activities of functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer area and adjacent areas.~~

Relationships with Other Functional Entities

1. Develop Reliability Standards that identify the functional entities responsible for complying with the Reliability Standard, including: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, Planning Coordinators, Transmission Planners, Resource Planners, and Distribution Providers.

2. Obtain the information necessary to monitor compliance with Reliability Standards from functional entities, including: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, Planning Coordinators, Transmission Planners, Resource Planners, and Distribution Providers.

3. Obtain the information necessary to complete registration from the appropriate functional entities, including: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, Planning Coordinators, Transmission Planners, Resource Planners, and Distribution Providers.

~~0. Coordinates reliability assurance activities of the functional entities within the Reliability Assurer area.~~

~~0. Coordinates reliability assurance activities with adjacent Reliability Assurers.~~

~~0. Coordinates critical infrastructure protection programs with functional entities.~~

~~0. Collects information from functional entities related to Reliability Assurance processes.~~

Planning Reliability and Planning Coordinator

Planning Reliability

Tasks

1. Establish data requirements necessary to develop power system models for analysis within the Planning Coordinator area. ~~Develop and maintain methodologies for the analysis and simulation of the transmission systems in the evaluation and development of transmission expansion plans and the analysis and development of resource adequacy plans.~~

2. Collect and validate information from Transmission Planners, such as modeling data, to perform a Transmission assessment of the Planning Coordinator area. ~~Define information required for planning purposes, and facilitate the process for consolidating and collecting or developing such information, including:~~

   - ~~Transmission facility characteristics and ratings.~~
   - ~~Demand and energy forecasts, capacity resources, and demand response programs.~~
   - ~~Generator unit performance characteristics and capabilities.~~
   - ~~Long-term capacity purchases and sales.~~

~~7.~~3. Assess the performance of the Transmission system, with the loads, resources, and proposed projects included in the Transmission Planner's Planning Assessment (including any Corrective Action Plan(s)). ~~Evaluate, develop, document, and report on resource and transmission expansion plans for the Planning Coordinator area. Integrate the respective plans, evaluate the impact of those plans on and by adjoining Planning Coordinator's integrated plans and assess whether the integrated plan meets reliability needs, and, if not, then to report on potential transmission system and resource adequacy deficiencies and suggest or facilitate the process for developing alternative plans to mitigate identified deficiencies.~~

   - ~~Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.~~
   - ~~Review transmission facility plans required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.~~
   - ~~Review and determine transfer capability (generally one year and beyond) as appropriate.~~
   - ~~Monitor and evaluate transmission expansion plan and resource plan implementation.~~
   - ~~Coordinate projects requiring transmission outages that can impact reliability and firm transactions.~~

~~13.~~4. Coordinate with adjoining Planning Coordinators to develop interconnection models with appropriate loads, resources, and System topology. ~~so that system models and resource and transmission expansion plans take into account modifications made to adjacent Planning Coordinator areas.~~

5. Evaluate and report on the performance of the consolidated Transmission assessments. ~~Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.~~

~~14.~~6. Evaluate interconnection reliability concerns among affected Planning Coordinators.

Planning Coordinator

Definition

The ~~functional~~ responsible entity that coordinates ~~, facilitates,~~ and integrates ~~and evaluates (generally one year and beyond)~~ transmission ~~f~~Facilit~~ies~~y and service plans, ~~and~~ resource plans, and Protection Systems.[8] ~~within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.~~

Introduction to the Planning Coordinator

By its very nature, BES planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems. The Planning Coordinator is responsible for coordinating the assessment~~ing~~ of the BES within its ~~the longer-term reliability of its~~ Planning Coordinator area. The PC assessment includes the collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one Transmission Planner; however, ~~While~~ the area under the purview of a Planning Coordinator may include as few as one Transmission Planner~~, and one Resource Planner,~~ ~~t~~The Planning Coordinator's scope of activities is intended to span a broader area that may include BES assets of multiple Transmission Planners. All BES Facilities should be assigned to a Transmission Planner and to a Planning Coordinator, so that there are no gaps in the assessment of the BES. ~~may include extended coordination with integrated Planning Coordinators' plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems.~~ Planning Coordinators work through a variety of processes ~~mechanisms~~ to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all portions of the interconnected BES ~~network areas with little or no ties to others' areas, such as interconnections,~~ are completely coordinated for planning activities.

Relationships with Other Functional Entities

1. Establish ~~Coordinates~~ power system modeling data requirements in conjunction with interconnected ~~and collects data for system modeling from~~ Transmission Planners ~~Resource Planner,~~ and other Planning Coordinators.
2. Collect data for power system modeling and assessments from the Transmission Planner.
~~2.~~3. Determine ~~Coordinates~~ transfer capability ~~(generally one year and beyond)~~with ~~Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and~~ neighboring Planning Coordinators.
~~3.~~4. Exchange information on ~~Coordinates~~ Contingencies, criteria, System Operating Limits (SOLs), Remedial Action Schemes (RAS), automatic load-shedding schemes, and plans with the Reliability Coordinator and other Planning Coordinators ~~on reliability issues~~.
~~4.~~5. Assess the performance of the Transmission system, in coordination with Transmission Planners~~Receives plans from Transmission Planners and Resource Planners~~.
~~5. Collects information including:~~
   - ~~Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.~~
   - ~~Demand and energy forecasts, capacity resources, and demand response programs from~~

[8] Definition of Planning Authority from the NERC Glossary of Terms (as of May 15, 2016). In the Glossary, Planning Coordinator and Planning Authority are defined interchangeably.

~~Load-Serving Entities, and Resource Planners.~~

~~. Generator unit performance characteristics and capabilities from Generator Owners.~~

~~. Long-term capacity purchases and sales from Transmission Service Providers.~~

~~10.~~6. Collect~~s~~ and review~~s~~ reports on ~~t~~Transmission, loads and resource~~s plan implementation~~ from ~~Resource Planners and~~ Transmission Planners.

~~11. Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Planning Coordinator area with Transmission Planners and Resource Planners and adjacent Planning Coordinator areas, as appropriate.~~

~~12. Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system.~~

~~13.~~7. Facilitate~~s~~ the integration of the respective plans of the ~~Resource Planners and~~ Transmission Planners within the Planning Coordinator area, and adjacent Planning Coordinator areas, as appropriate.

a. Review~~s~~ the integrated plan with respect to established reliability needs considering the impact on and by adjoining ~~s~~Systems.

b. In coordination with the ~~Resource Planners and~~ Transmission Planners, facilitate~~s~~ the development of alternative solutions for plans that do not meet those reliability performance criteria ~~needs~~.

Transmission Planning and Transmission Planner

Transmission Planning

Tasks

1. Develop and ~~M~~maintain ~~and develop, in cooperation with adjacent and overlapping Transmission Planners,~~ methodologies, criteria and tools for the analysis and simulation of the ~~t~~Transmission systems ~~in the evaluation and development of transmission expansion plans related to resource adequacy plans~~.

2. ~~Define, consolidate and collect or d~~Develop, acquire and validate~~, in cooperation with adjacent and overlapping Transmission Planners,~~ information required for Transmission assessments~~planning purposes~~ including:

    a. Transmission ~~f~~Facility characteristics and ~~r~~Ratings.

    b. Demand and Electrical ~~e~~Energy forecasts, capacity resources, and Demand-Side Management (DSM) ~~demand response~~ programs.

    c. Generator unit performance characteristics and capabilities.

    d. Commitments for firm Transmission Interchange.~~Long-term capacity purchases and sales~~

    e. Load forecasts and generation dispatch scenarios.

3. Develop and ~~M~~maintain ~~transmission~~ power system models (steady state, dynamics, and short circuit) necessary for the assessment of Transmission system ~~to evaluate Bulk Electric System~~ performance for identified scenarios.

4. Exchange information with other ~~Coordinate with adjacent and overlapping~~ Transmission Planners and the Planning Coordinator to achieve an interconnected ~~so that system~~ model~~s and resource and transmission expansion plans take into account modifications made to adjacent and overlapping Transmission Planner areas~~.

5. ~~Evaluate, develop, document, and report on expansion plans for the Transmission Planner area.~~ Assess the performance of the Transmission system with the anticipated topology and scenarios of loads and resources ~~whether the integrated plan meets reliability needs, and, if not, report on potential network conditions or configurations that do not meet performance requirements and provide potential alternative solutions to meet performance requirements~~.

    ~~. Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.~~

    ~~. Evaluate and plan for all requests required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.~~

    ~~. Determine transfer capability values (generally one year and beyond) as appropriate.~~

    ~~. Monitor, evaluate and report on transmission expansion plan and resource~~

~~plan implementation.~~

- ~~Coordinate projects requiring transmission outages that can impact reliability and firm transactions.~~

~~5. Notify Generation Owners, Resource Planners, Transmission Planners and Transmission Owners of any planned transmission changes that may impact their facilities.~~

~~5. Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.~~

Transmission Planner

Definition

The ~~functional~~ entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority ~~a Transmission Planner~~ area.[9]

Introduction to the Transmission Planner

The Transmission Planner is responsible for assessing the long~~er~~ term (generally one year and beyond) Transmission system performance within ~~reliability of~~ its Transmission Planner area. The TP assessment includes the collection of Transmission assets over which the Transmission Planner is responsible for planning ("TP Area"). By its very nature, BES~~ulk Electric System~~ planning involves multiple entities. Since all electric ~~s~~Systems within an integrated network are electrically connected, changes planned in ~~whatever~~ one part of the ~~s~~System ~~does~~ can affect the other parts of the ~~s~~System~~s~~. Transmission Planners coordinate their plans with the adjoining Transmission Planners to assess impact on or by those plans. The area under the purview of a Transmission Planner may include one or more Resource Planner areas~~ and overlap one or more adjacent Transmission Planners.~~ All BES Facilities should be under the purview of at least one Transmission Planner.

Relationships with Other Functional Entities

1. Coordinate~~s~~ and collect~~s~~ data (steady state, dynamics, and short circuit) for power system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, Resource Planners~~, other Transmission Planners,~~ Transmission Owners, ~~and~~ Transmission Service Providers, and other Transmission Planners.
2. Collect~~s~~ information including:
    a. Transmission facility characteristics and ~~r~~Ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.
    b. Demand and Electrical ~~e~~Energy forecasts, capacity resources, and ~~d~~Demand-Side Management ~~response~~ programs from Load-Serving Entities, and Resource Planners.
    c. Generator unit performance characteristics and capabilities from Generator Owners.
    d. Commitments for firm Transmission Interchange ~~Long-term transmission capacity purchases and sales~~ from Transmission Service Providers.
3. Inform~~s~~ Resource Planners and other Transmission Planners of the methodologies and tools for the simulation of the ~~t~~Transmission system.

~~4. Coordinates with Resource Planners and other Transmission Planners on Bulk Electric System expansion plans.~~

~~5.~~4. Coordinate~~s~~ ~~the evaluation of~~ BES~~ulk Electric System~~ expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

~~6.~~5. Report~~s~~ on and coordinate~~s~~ its BES~~ulk Electric System~~ expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service

[9] Definition of Transmission Planner from the NERC Glossary of Terms (as of May 15, 2016).

Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

~~7.~~6. Notify~~ies~~ other Transmission Planners, Transmission Owners, Transmission Operators and other entities that may be impacted by~~of~~ any planned BES~~ulk Electric System~~ changes.

~~8.~~7. Coordinate~~s~~ with Distribution Providers, Transmission Owners, Generator Owners and Load-Serving Entities in the evaluation and plans for all requests required to integrate new (~~E~~end-use ~~C~~customer, generation, and ~~t~~Transmission) ~~f~~Facilities into the BES~~ulk Electric System~~.

~~9.~~8. Submit~~s~~ and coordinate~~s~~ the plans for the interconnection of ~~f~~Facilities to the BES~~ulk Electric System~~ within its Transmission Planner area with other Transmission Planners and the Planning Coordinator~~Resource Planners~~, as appropriate.

~~10.~~9. Coordinate~~s~~ and develop~~s~~ ~~t~~Transfer ~~c~~Capability values with other Transmission Planners, Reliability Coordinators, Transmission Operators, Transmission Owners, ~~and~~ Transmission Service Providers, and the Planning Coordinator.

~~11.~~10. Coordinate~~s~~ with Transmission Owners and Generator Owners to define system protection and control needs and requirements, including ~~special protection systems (r~~Remedial ~~a~~Action ~~s~~Schemes~~),~~ to meet reliability needs.

11. Receive~~s~~ maintenance schedules and construction plans from Transmission Operator or Transmission Owner for input into and evaluation of BES~~ulk Electric System~~ expansion plans.

Resource Planning and Resource Planner

Resource Planning

Tasks

~~1. Consider generation capacity from resources both within and outside of the Resource Planner area for assessing resource adequacy.~~

~~2. Monitor and report, as appropriate, on its resource plan implementation.~~

~~3.~~1. ~~Develop and maintain resource (demand and capacity) models~~ Acquire or develop the tools needed to evaluate long-term resource ~~a~~Adequacy for a specific set of loads.

~~4.~~2. ~~Collect~~ Acquire or develop the data and information required for performing periodic resource ~~a~~Adequacy ~~purposes~~assessments.~~, including:~~

- ~~demand and energy forecasts, capacity resources, and demand response programs,~~
- ~~generator unit performance characteristics and capabilities, and~~
- ~~long-term capacity purchases and sales and~~
- ~~transmission (interface) limits.~~

3. Determine the reliability criteria used as the basis for assessing long-term resource Adequacy.

~~9.~~4. Perform periodic resource Adequacy assessments and document the results.

5. Evaluate future ~~, develop, document, and report on a~~ resource alternatives~~. adequacy plan for its portion of the Transmission Planner and Planning Coordinator area~~.

~~10.~~6. Create and periodically update a long-term resource plan~~Assist in the evaluation of the deliverability of resources~~.

Resource Planner

Definition

The ~~functional~~ entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority ~~Resource Planner~~ area.[10]

Relationships with Other Functional Entities

1. Collect data and information required for performing periodic resource Adequacy assessments from one or more of the following entities as necessary: Load-Serving Entity, Generator Owner, Generator Operator, Transmission Planner, Planning Coordinator, and Transmission Service Provider.

~~1.~~2. Provide long-term ~~Coordinates the~~ resource plan information ~~models with~~ to the ~~its~~ Transmission Planner for power system modeling and Planning Assessments~~Planning Coordinator~~.

~~2.~~3. Receive information from~~Coordinates with~~ the ~~Transmission Owners and~~ Transmission Planners regarding submitted resource plan ~~on the~~ deliverability ~~of resources to customers~~.

~~3.~~4. Provide resource plan recommendations to the affiliated ~~Coordinates with and collects data for resource planning from the Load-Serving Entities,~~ Generator Owner and Load-Serving Entity~~s, Generator Operators, Transmission Planners, Transmission Operators, Interchange Coordinators, and Reliability Assurers~~.

~~4.~~5. Coordinate~~s~~ with Transmission Planners~~,~~ and Transmission Service Providers~~, Reliability Coordinators, and Planning Coordinators~~ on resource ~~adequacy~~ plans.

~~5. Coordinates with adjoining Resource Planners within the Planning Coordinator area to avoid the double-counting of resources.~~

~~6. Reports its resource plan to the Transmission Planner and Planning Coordinator for evaluation and compliance with Reliability Standards.~~

~~7.~~6. Assess alternative ~~Works~~ plans with ~~the Planning Coordinator and~~ Transmission Planners to identify potential alternative ~~transmission~~ solutions to meet ~~Resource Planner~~resource Adequacy ~~plans~~requirements.

~~8. Applies methodologies and tools for the analysis and development of resource adequacy plans from the Planning Coordinator.~~

[10] Definition of Resource Planner from the NERC Glossary of Terms (as of May 15, 2016).

Reliability Operations and Reliability Coordinator

Reliability Operations

Tasks

1. Monitor all reliability-related parameters within the reliability area, including generation dispatch and ~~generation/transmission~~ maintenance plans for generation and Transmission.
2. Identify, communicate, and direct actions if necessary to relieve reliability threats and limit violations in the reliability area.
3. Develop Interconnection Reliability Operating Limits (to protect from instability and Cascading).
4. Assist in determining Interconnected Operations Services (IOS) ~~reliability-related services~~ requirements for:
    a. balancing generation and load,[11] and
    b. ~~transmission~~ reliability of Transmission ~~(*e.g.*, reactive requirements, location of operating reserves).~~
5. Perform reliability analysis (actual and ~~c~~Contingency) for the reliability area.
6. Direct revisions to ~~t~~Transmission maintenance plans as permitted by ~~a~~Agreements.
7. Direct revisions to generation maintenance plans as permitted by ~~a~~Agreements.
8. Direct implementation of emergency[12] procedures including load-shedding.
9. Direct and coordinate restoration of the BES for its RC Area~~system restoration~~.
10. Curtail Confirmed Interchange that adversely impacts reliability.
11. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

~~11.~~12. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[11] The Glossary definition of "Load" is not appropriate because the Glossary definition refers to end-use customer or end-use device; the Glossary definition does not incorporate the concept of quantity.
[12] The Glossary definition of "Emergency" is not appropriate because the definition is limited in application to the BES. In this context, the RC may encounter an emergency situation that is broader than the circumstances described in the Glossary definition.

Reliability Coordinator

Definition

~~The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.~~The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.[13]

Introduction to the Reliability Coordinator

The Reliability Coordinator maintains the Real-time operating reliability of its Reliability Coordinator Area and in coordination with its neighboring Reliability Coordinator's ~~w~~Wide-~~a~~Area view. Wide-Area view means the entire Reliability Coordinator area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.[14] The ~~w~~Wide-~~a~~Area view includes situational awareness of its neighboring Reliability Coordinator Areas. ~~Its scope includes both transmission and balancing operations~~The RC ~~, and it~~ has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably. Its scope includes both:

1. **Transmission operations**. With respect to transmission operations, the Reliability Coordinator and Transmission Operator have similar roles, but different scopes. The Transmission Operator directly maintains reliability for its Transmission Operator Area~~own defined area~~. However, the Reliability Coordinator also maintains reliability, in concert with the other Reliability Coordinators, for the Interconnection as a whole. Thus, the Reliability Coordinator needs a ~~"w~~Wide-~~a~~Area~~"~~ view that reaches beyond its boundaries to enable it to operate within Interconnection Reliability Operating Limits. The Transmission Operator may or may not have this ~~"w~~Wide-~~a~~Area~~"~~ view, but the Reliability Coordinator does have it. The Reliability Coordinator may direct a Transmission Operator within its Reliability Coordinator Area to take whatever action is necessary to ensure that Interconnection Reliability Operating Limits are not exceeded.

2. **Balancing operations**. The Reliability Coordinator ensures that the generation-~~d~~Demand balance is maintained within its Reliability Coordinator Area, which, in turn, ensures that the Interconnection frequency remains within acceptable limits. The Balancing Authority has the responsibility for generation-~~d~~Demand-~~i~~Interchange balance in the Balancing Authority Area. The Reliability Coordinator may direct a Balancing Authority within its Reliability Coordinator Area to take whatever action is necessary to ensure that this balance does not adversely impact reliability.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinate~~s~~ with other Reliability Coordinators, Transmission Planners, and Transmission

[13] Definition of Reliability Coordinator from the NERC Glossary of Terms (as of May 15, 2016).
[14] Definition of "Wide-area" from the NERC Glossary of Terms (as of May 15, 2016).

Service Providers on ~~t~~Transmission system[15] limitations.

2. Receive~~s~~ facility[16] and operational data from Generator Operators, Distribution Providers, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators.
3. Receive~~s~~ generation dispatch from Balancing Authorities and issue~~s~~ dispatch adjustments to Balancing Authorities to prevent exceeding limits within the Reliability Coordinator Area (if not resolved through market mechanisms).
4. Receive~~s~~ integrated operational plans from Balancing Authorities for reliability analysis of Reliability Coordinator Area.
5. Receive~~s~~ ~~t~~Transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis.
6. ~~Develops~~Provide Interconnection Reliability Operating Limits (IROLs)~~, based on Transmission Owners' and Generator Owners' specified equipment ratings,~~ ~~and provides them~~ to those functional entities with a reliability-related need~~Transmission Operators~~.
7. Assist~~s~~ Transmission Operators in calculating and coordinating System Operating Limits.
8. Provide~~s~~ reliability analyses to Transmission Operators, Generator Operators and Balancing Authorities in its area as well as other Reliability Coordinators.
9. Direct~~s~~ Generator Owners and Transmission Owners to revise generation and ~~t~~Transmission maintenance plans that are adverse to reliability.
10. Receive~~s~~ balancing information from Balancing Authorities for monitoring.
11. Receive~~s~~ final approval or denial of Arranged Interchange from Interchange Coordinator.

~~12. Provide IROLs and TTC to the Transmission Service Provider for ATC calculation.~~

~~13.~~12. Develops operating agreements or procedures with Transmission Owners.

~~14.~~13. Coordinate~~s~~ with Transmission Operators on ~~system~~ restoration plans, contingency[17] plans and Interconnected Operations Services (IOS)~~reliability-related services~~.

Real-time

~~15.~~14. Coordinate~~s~~ reliability processes and actions with and among other Reliability Coordinators.

~~16.~~15. Receive~~s~~ Real-time operational information from Balancing Authorities, Interchange Coordinators and Transmission Operators for monitoring.

~~17.~~16. Issue~~s~~ reliability alerts to Generator Operators, Transmission Operators, Transmission Service Providers, Balancing Authorities, Interchange Coordinators, Regional Entities and NERC.

~~18.~~17. Issue~~s~~ corrective actions and ~~e~~Emergency procedure~~s~~ directives ~~(*e.g.*, curtailments or load shedding)~~ to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange Coordinators.

[15] The Glossary definition of "System" is not appropriate in this context because the limitations may not always include a combination of generation, transmission, *and* distribution.

[16] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application to include non-BES elements (*e.g.*, industrial equipment).

[17] The Glossary definition of "Contingency" is not appropriate because application in this context is not limited to power system contingency (*i.e.*, N-1 event); in this context, intended to have broader meaning.

~~19.~~18. Specify~~ies~~ reliability–related requirements to Balancing Authorities.

~~20.~~19. Receive~~s~~ verification of ~~e~~Emergency procedures from Balancing Authorities.

~~21.~~20. Receive~~s~~ notification of Confirmed Interchange changes from Balancing Authorities.

~~22.~~21. Order~~s~~ re-dispatch of generation by Balancing Authorities.

~~23.~~22. Direct~~s~~ use of flow control devices by Transmission Operators.

~~24.~~23. Respond~~s~~ to requests from Transmission Operators to assist in mitigating equipment overloads.

Balancing and Balancing Authority

Balancing

Tasks

1. Control any of the following combinations within a Balancing Authority Area:
    a. ~~Load and generation (an isolated system)~~Demand and resource
    b. ~~Load~~ Demand and Confirmed Interchange
    c. Generation and Confirmed Interchange
    d. Generation, ~~load~~Demand, and Confirmed Interchange
2. Calculate ~~a~~Area ~~c~~Control ~~e~~Error (ACE) within the reliability area.
3. Operate in the Balancing Authority Area to maintain Demand and resource~~load-interchange-generation~~ balance.
4. Review generation commitments, dispatch, and ~~load~~ Demand forecasts.
5. Formulate an operational plan (*e.g.,* generation commitment, outages~~, etc.~~) for reliability evaluation.
6. Approve Arranged Interchange from ~~r~~Ramping ability perspective.
7. Implement Confirmed Arranged Interchange.
8. Operate the Balancing Authority Area to contribute to Interconnection frequency.
9. Monitor and report control performance and disturbance[18] recovery.
10. Provide balancing and energy accounting (including hourly checkout of Confirmed Arranged Interchange, Implemented Interchange and actual ~~i~~Interchange), and administer inadvertent energy paybacks.
11. Determine needs for Interconnected Operations Services~~reliability-related services~~.
12. Deploy Interconnected Operations Services (IOS)~~reliability-related services~~.
13. Implement ~~e~~Emergency procedures.
14. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
~~14.~~15. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[G] The Glossary definition of "Contingency" is not appropriate because the definition is too broad.

Balancing Authority

Definition

The ~~functional~~ responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports ~~contributes to~~ Interconnection frequency in real time.[19]

Relationships with Other Functional Entities

Ahead of Time

1. Receive generator Facility plans from Generator Operators within the Balancing Authority Area.
2. Receive operational data from Generator Operators within the Balancing Authority Area.
3. ~~1.~~ Receive~~s~~ operating and availability status of generating units ~~and operational plans and commitments~~ from Generator Operators ~~(including annual maintenance plans)~~ within the Balancing Authority Area.
4. ~~Receives annual maintenance plans from Generator Owners within the Balancing Authority Area.~~
5. ~~3.~~ Receive~~s~~ reliability evaluations from the Reliability Coordinator.
6. ~~Receives final approval or denial of a request for an Arranged Interchange from the Interchange Coordinators.~~
7. Compile~~s~~ ~~load~~Demand forecasts from Load-Serving Entities.
8. Develop~~s~~ ~~a~~Agreements with adjacent Balancing Authorities for ACE calculation parameters.
9. Submit~~s~~ integrated operational plans to the Reliability Coordinator for reliability evaluation and provides balancing information to the Reliability Coordinator for monitoring.
10. ~~Confirms~~ Receive Arranged Interchange from~~with~~ Interchange Coordinators.
11. ~~Confirms~~ Send approval or denial of Arranged Interchange based on meeting ~~r~~Ramping requirements ~~capability~~ to ~~with~~ Interchange Coordinators.
12. ~~9.~~10. Receive notice of final approval or denial of Arranged Interchange becoming Confirmed Interchange from the Interchange Coordinator.
13. ~~10.~~11. Implement~~s~~ generator commitment and dispatch schedules from the Load-Serving Entities ~~and Generator Operators~~ who have arranged for ~~generation~~ resources within the Balancing Authority Area.
14. ~~11.~~12. Acquires Interconnected Operations Services (IOS) ~~reliability-related services~~ from Generator Operator.
15. ~~12.~~13. Receive~~s~~ dispatch adjustments from Reliability Coordinators to prevent exceeding limits.
16. Receives generator information from Generator Owners including unit maintenance schedules and retirement plans.
17. ~~13.~~15. Receive reports on frequency regulating equipment from Generator Operators within the Balancing Authority Area.

[19] Definition of Balancing Authority from the NERC Glossary of Terms (as of May 15, 2016).

~~14.~~16. Receive~~s~~ information from Load-~~-~~Serving Entities on self-provided Interconnected Operations Services (IOS) ~~reliability-related services~~.

~~15.~~17. Coordinate~~s~~ ~~system~~ restoration plans (*i.e.*, any combination of generation, Transmission or distribution components) with the Transmission Operator.

~~16.~~18. Provide~~s~~ ~~generation~~ resource dispatch to Reliability Coordinators.

Real-time

~~17.~~19. Coordinate~~s~~ use of Interruptible Demand ~~controllable loads~~ with Load-Serving Entities ~~(*i.e.*, interruptible load that has been bid in as a reliability-related service or has agreed to participate in voluntary load shedding program under resource/reserve deficiency situations)~~.

~~18.~~20. Receive~~s~~ loss allocation from Transmission Service Providers (for repayment with in-kind losses).

~~19.~~21. Receive~~s~~ Real-time operating information from the Transmission Operator, adjacent Balancing Authorities and Generator Operators.

~~20.~~22. Receive~~s~~ operating information from Generator Operators.

~~21.~~23. Provide~~s~~ Real-time operational information for Reliability Coordinator monitoring.

~~22.~~24. Receive~~s~~ reliability alerts from Reliability Coordinator.

~~23.~~25. Comply~~ies~~ with reliability-related requirements (*e.g.*, reactive requirements, location of operating reserves) specified by Reliability Coordinator.

~~24.~~26. Verify~~ies~~ implementation of ~~e~~Emergency procedures to Reliability Coordinator.

27. Inform~~s~~ Reliability Coordinator and Interchange Coordinators of Confirmed Interchange changes (*e.g.*, due to Demand ~~generation~~ or resource~~load~~ interruptions) involving its Balancing Authority Area.

~~25.~~28. Receive Confirmed Interchange revisions (including Curtailments) from Interchange Coordinators.

~~26.~~29. Direct~~s~~ resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in ~~r~~Real-~~-~~time.

~~27.~~30. Request ~~Directs~~ Transmission Operator (or Distribution Provider) to reduce voltage to lower Demand or shed load if needed to ensure balance within its Balancing Authority Area.

~~28.~~31. Direct~~s~~ Generator Operators to implement re-dispatch for congestion management as directed by the Reliability Coordinator.

~~29.~~32. Implements corrective actions and ~~e~~Emergency procedures as directed by the Reliability Coordinator.

~~30.~~33. Implement~~s~~ ~~system~~ restoration plans (*i.e.*, any combination of generation, Transmission or distribution components) as directed by the Transmission Operator.

~~31.~~34. Direct~~s~~ Transmission Operator to implement flow control devices.

~~31. Receives information of Implemented Interchange and Confirmed Interchange curtailments from Interchange Coordinator.~~

After the hour

~~32.~~35. Confirm~~s~~ Implemented Interchange with Confirmed Interchange provided by the Interchange Coordinators after the hour for "checkout."

36. Confirm~~s~~ Implemented Interchange and Confirmed Interchange with adjacent Balancing Authorities

after the hour for “checkout.”

~~33.~~37. Request record of individual Confirmed Interchange from Interchange Coordinator.

Market Operations and Market Operator (Resource Integrator)

Market Operations

Tasks

1. The m~~M~~arket ~~O~~operations function, its tasks, and the interrelationships with other entities are included in the Functional Model only as an interface point of reliability ~~F~~functions with commercial functions.

Market Operator (Resource Integrator)

Definition

The market entity whose interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.

Relationships with Other Functional Entities

Market oOperator tasks and relationships are specific to a particular market design and will depend on the market structure over which the ~~M~~market ~~O~~operator presides.

Transmission Operations and Transmission Operator

Transmission Operations

Tasks

1. Monitor and provide telemetry (as needed) of all reliability-related parameters within the reliability area.
2. Monitor the status of, and deploy, facilities[20] classed as ~~t~~Transmission assets, which may include the ~~t~~Transmission lines connecting a generating plant to the ~~t~~Transmission system, associated protective relaying systems and Remedial Action Schemes~~Special Protection Systems~~.
3. Develop ~~s~~System limitations (*e.g.*, ~~, such as~~ System Operating Limits) ~~and Total Transfer Capabilities,~~ and operate within those limits.
4. Develop and implement ~~e~~Emergency procedures.
5. Develop and implement ~~s~~System restoration plans.
6. Operate within established Interconnection Reliability Operating Limits.
7. Perform reliability analysis ~~(actual and contingency)~~ for the Transmission Operator Area.
8. Adjust Real Power, Reactive Power and voltage ~~flow control devices within the transmission area~~ to maintain reliability.

~~9. Deploy reactive resources to maintain transmission voltage within defined limits.~~

~~10.~~9. Determine the Transmission capability that supports the Reliable Operation of the Transmission Operator Area.

~~11.~~10. Operate or direct the operation of Transmission Facilities in its TOP Area.

11. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

12. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[20] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application to include responsibilities for non-BES elements.

Transmission Operator

Definition

The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.[21] ~~The functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area.~~

Introduction to the Transmission Operator

The Transmission Operator is responsible for the Real-time operating reliability of the ~~t~~Transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

The Transmission Operator and Reliability Coordinator have similar roles with respect to the reliability of the ~~t~~Transmission system~~operations~~, but have different responsibilities ~~scopes~~. The Transmission Operator shares a role in monitoring the Transmission system with ~~scope is narrower than~~ the Reliability Coordinator and additionally, has the operational responsibility for the Transmission system area under its purview.~~and the Transmission Operator does not necessarily "see" very far beyond its own boundaries. Therefore, t~~ The Transmission Operator can calculate System Operating Limits, but does not necessarily have the Wide-area view of the Reliability Coordinator ~~will not necessarily~~ necessary to calculate Interconnection Reliability Operating Limits.~~, which requires the wider scope of the Reliability Coordinator.~~

Relationships with Other Functional Entities

Ahead of Time

1. Coordinate~~s~~ restoration plans with Reliability Coordinator, Transmission Operators, Balancing Authorities, and Distribution Providers.
2. Receive~~s~~ maintenance requirements and construction plans and schedules from the Transmission Owners and Generation Owners.
3. Receive~~s~~ Interconnection Reliability Operating Limits as established by the Reliability Coordinator.
4. Receive~~s~~ reliability evaluations from the Reliability Coordinator.
5. Develop~~s~~ agreements (Operating Plans, procedures, and processes) with adjacent Transmission Operators ~~for joint transmission facilities~~.
6. Define~~s~~ Total Transfer Capabilities and System Operating Limits based on facility[22] information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator.
7. Arrange~~s~~ for Interconnected Operations Services (IOS) ~~reliability related services~~ from Generator Operators (*e.g.*, voltage schedules, VAR Demand schedule).
8. Develop~~s~~ contingency plans, and monitors operations of the ~~t~~Transmission facilities within the Transmission Operator Area control and as directed by the Reliability Coordinator.
9. Provide~~s~~ facility and operating information to the Reliability Coordinator.
10. Provide~~s~~ to the Transmission Planner information on the capability to ~~c~~Curtail (reduce) and shed load during ~~e~~Emergencies.

[21] Definition of Transmission Operator from the NERC Glossary of Terms (as of May 15, 2016).

[22] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application to include responsibilities for non-BES elements.

11. Provide~~s~~ Total Transfer Capabilities, ~~and~~ System Operating Limits, and methodology for calculating ~~to, and coordinates~~ Available Transfer Capability for respective Transmission paths to~~with,~~ Transmission Service Provider.

12. Receive~~s~~ operating and availability status of generating units from Generat~~or~~ion Operators including status of automatic voltage regulators and power system stabilizers.

~~12.~~13. Receive operational data from Generator Operators.

~~13.~~14. Develop~~s~~ operating agreements or procedures with Transmission Owners.

Real-time

~~14.~~15. Coordinates load shedding with, or as directed by, the Reliability Coordinator.

~~15.~~16. Provide~~s~~ Real-time operations information to the Reliability Coordinator and Balancing Authority.

~~16.~~17. Notify~~ies~~ Generator Operators of ~~t~~Transmission system problems (*e.g.*, voltage limitations or equipment overloads that may affect generator operations).

~~17.~~18. Request~~s~~ Reliability Coordinator to assist in mitigating equipment overloads. (*e.g.*, re-dispatch, ~~t~~Transmission loading relief).

~~18.~~19. Deploy~~s~~ reactive resources from Transmission Owners, ~~and~~ Generator Owners, and Distribution Providers ~~-~~to maintain acceptable voltage profiles.

~~19.~~20. Direct~~s~~ Distribution Providers to shed load if needed to ensure reliability within the Transmission Operator Area.

~~20.~~21. Implement~~s~~ flow control device operations for those ties under the Transmission Operator's purview as directed by the Balancing Authorities or Reliability Coordinator.

~~21.~~22. Receive~~s~~ reliability alerts from Reliability Coordinator.

~~22.~~23. Direct~~s~~ Balancing Authorities and Distribution Providers to implement system restoration plans.

~~23.~~24. Receive Real-time operating information from Generator Operators.

Interchange and Interchange Coordinator

Interchange

Tasks

1. Receive completed Request for Interchange (RFI) (*i.e.*, valid source and sink, Transmission arrangements) ~~an Arranged Interchange~~.
2. Transition RFI to ~~Ensure an~~ Arranged Interchange ~~is balanced and valid (Balancing Authority and Transmission Service Provider validation of sources and sinks, transmission arrangements, reliability-related services, etc.)~~.
3. Forward Arranged Interchange to entities for ~~Coordinate (*i.e.*, collect and consolidate)~~ approval, change, or~~and~~ denial ~~requests for an Arranged Interchange to become Confirmed Interchange~~. ~~Approvals may be explicit or by exception.~~
4. Collect approvals and denials ~~Receive confirmations~~ of requested Arranged Interchange.
5. Communicate status of an Arranged Interchange that becomes Confirmed Interchange or otherwise.
6. Communicate Confirmed Interchange information to the appropriate reliability assessment tools (*e.g.*, the interchange distribution calculator in the Eastern Interconnection).
7. Submit Arranged Interchange for Curtailments and re-dispatch implementation requests.

~~7.~~8. Maintain record of an individual Confirmed Interchange.

~~8.~~9. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

~~9.~~10. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Interchange Coordinator

Definition

The ~~functional~~ responsible entity that authorizes ~~ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates~~ implementation of valid and balanced Interchange Schedules ~~Confirmed Interchange~~ between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.[23]

Relationships with Other Functional Entities

Ahead of Time

1. Receive~~s~~ Requests for ~~Arranged~~ Interchange from Generation Owner, Purchasing-Selling Entity, and Load-~~-~~Serving Entit~~y~~ies~~s~~.
2. Submit~~s~~ ~~request for an~~ Arranged Interchange to become Confirmed Interchange to the Balancing Authorities and Transmission Service Providers for approvals.
3. Receive~~s~~ approval or denial from Transmission Service Providers of ~~t~~Transmission arrangement(s) for Arranged Interchange.
4. Receive~~s~~ approval or denial from Balancing Authorities of the ability to meet ~~r~~Ramping requirements for submitted Arranged Interchange.
5. Receives approval from Generation Owners, Purchase-Selling Entities, or Load-Serving Entities for any revised Arranged Interchange.
6. Communicate~~s~~ final approval or denial of a request for an Arranged Interchange to become Confirmed ~~i~~Interchange to the Reliability Coordinator, Balancing Authorities, Transmission Service Providers, Generation Owners, ~~and~~ Purchasing-Selling Entities, and Load-Serving Entities for implementation ~~and NERC identified reliability analysis services~~.

Real-time

7. Receive reliability alerts from the Reliability Coordinators.
8. Receive~~s~~ ~~c~~Curtailments and re-dispatch implementation requests from Reliability Coordinators and submits ~~for an~~ Arranged Interchange.
9. Receive~~s~~ information on Confirmed Interchange interruptions from the Balancing Authorities and communicates the Confirmed Interchange status to Balancing Authorities, Transmission Service Providers, Reliability Coordinators, Generation Owner, and Purchasing-Selling Entities, and ~~/~~Load- Serving Entities.
10. Inform~~s~~ Reliability Coordinators, Balancing Authorities, Transmission Service Providers, Generation Owners, Purchasing-Selling Entities, and~~/~~ Load-Serving Entities~~, Reliability Coordinators, and Balancing Authorities~~ of Confirmed Interchange revisions (including ~~c~~Curtailments).

After the hour

11. ~~Maintains and p~~Provide~~s~~ a record of individual Confirmed Interchange to requesting ~~for which it coordinated with the~~ Balancing Authorities.

[23] Definition of Interchange Authority from the NERC Glossary of Terms (as of May 15, 2016). The Glossary uses the term "Interchange Authority" whereas the Functional Model uses the term "Interchange Coordinator."

12. Coordinate~~s~~ Confirmed Interchange with Balancing Authorities after the hour for "checkout."

Transmission Service and Transmission Service Provider

Transmission Service

Tasks

1. Receive ~~t~~Transmission ~~s~~Service requests and process each request for service according to the requirements of the tariff.
    a. Maintain commercial interface for receiving and confirming requests for ~~t~~Transmission ~~s~~Service according to the requirements of the tariff (*e.g.*, OASIS).
2. Determine and post available transfer ~~capability~~ capacity values.
3. Approve or deny ~~t~~Transmission ~~s~~Service requests.
4. Approve or deny Arranged Interchange from ~~t~~Transmission ~~s~~Service arrangement perspective.
5. Allocate ~~t~~Transmission losses (MWs or funds) among Balancing Authority Areas.
6. Acquire Ancillary Services to support Transmission Service.
~~5.~~7. Update information that is relevant to a long-term Transmission Service arrangement.

Transmission Service Provider

Definition

The ~~functional~~ entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable ~~t~~Transmission ~~s~~Service agreements.[24]

Relationships with Other Functional Entities

Ahead of Time

1. Receive the methodology to determine available transfer capacity from the Transmission Operator.

~~1.~~2. Receive~~s~~ Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from ~~Planning Coordinator,~~ the Transmission Planner~~,~~ Transmission Operator and Reliability Coordinator, and coordinates ~~A~~available ~~T~~transfer capacity~~Capability~~ with these entities and other Transmission Service Providers.

~~2. Receives transmission Facility Ratings from Transmission Owners.~~

3. Receive~~s~~ ~~t~~Transmission expansion plans identified by the Transmission Planner(s) ~~Planning Coordinator~~ to help determine ability to accommodate long-term ~~t~~Transmission ~~s~~Service requests.

4. Arrange for providers of Ancillary Services, and notify the Transmission Operator and Balancing Authority.

5. ~~Approves~~ Accept or ~~denies~~ decline ~~t~~Transmission ~~s~~Service requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities.

~~6. Confirms validity of transmission service requests indicated in the Arranged Interchange with Interchange Coordinators.~~

~~7.~~6. Develop~~s~~ ~~a~~Agreements or procedures with Transmission Owners.

7. Receive~~s~~ ~~final approval or denial of~~ Arranged Interchange from Interchange Coordinator.

8. Send approval or denial of Arranged Interchange to Interchange Coordinator based on meeting Transmission Service arrangements.

9. Receive notice of final approval or denial of Arranged Interchange becoming Confirmed Interchange from Interchange Coordinator.

10. Receives updated information from Balancing Authority, Resource Planner, Load-Serving Entity, Purchasing-Selling Entity, and market operator for long-term Transmission Service arrangement.

Real-time

~~8.~~11. Receive~~s~~ Confirmed Interchange revisions ~~implementation~~ (including ~~c~~Curtailments) from the Interchange Coordinators.

12. Receive Confirmed Interchange Interruption status from Interchange Coordinator.

~~9.~~13. Receive~~s~~ reliability alerts from Reliability Coordinator.

14. Provide~~s~~ loss allocation to Balancing Authorities.

[24] Definition of Transmission Service Provider from the NERC Glossary of Terms (as of May 15, 2016).

15. Notify the Transmission Operator and Balancing Authority of changes to Ancillary Services.

Transmission Ownership and Transmission Owner

Transmission Ownership

Tasks

1. Develop interconnection ~~a~~Agreements.
2. Establish ~~r~~Ratings of ~~t~~Transmission facilities.~~-~~[25]
3. Maintain ~~t~~Transmission facilities and rights-of-way.
4. Design and install owned facilities classified as ~~t~~Transmission and obtain associated rights-of-way.
5. Design and authorize maintenance of ~~t~~Transmission protective relaying systems and ~~Special Protection Systems~~Remedial Action Schemes.
6. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
7. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[25] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application for non-BES elements.

Transmission Owner

Definition

The ~~functional~~ entity that owns and maintains transmission ~~f~~Facilities.[26]

Relationships with Other Functional Entities

1. Coordinate~~s~~ with Transmission Planners, ~~and~~ the Planning Coordinator, ~~Generator Owners,~~ and other Transmission Owners, ~~and Load-Serving Entities~~ desiring to connect with the Transmission system under the purview of the Transmission Owner. ~~the Bulk Electric System.~~
2. Receive~~s~~ approved ~~t~~Transmission expansion plans from the Transmission Planner.
3. Develop~~s~~ agreements or procedures with the Transmission Service Providers.
4. Develop~~s~~ operating agreements or procedures with the Transmission Operators, Reliability Coordinators and Distribution Providers.
5. Develop~~s~~ agreements with adjacent Transmission Owners for joint ~~t~~Transmission facilities.
6. Provide~~s~~ ~~t~~Transmission expansion plans and changes to the Planning Coordinator and Transmission Planners.
7. Provide~~s~~ ~~t~~Transmission Facility Ratings to Transmission Operators, Reliability Coordinators, Transmission Service Providers, Distribution Providers, Transmission Planners, and Planning Coordinator.
8. Provide~~s~~ maintenance and construction plans and schedules to the Reliability Coordinator, Transmission Operator, and Transmission Planner.
9. Coordinate and ~~D~~develop~~s~~ interconnection agreements with the Distribution Providers, ~~and~~ Generation Owners, and Load Serving Entities desiring to connect with the Transmission system under the purview of the Transmission Owner ~~for connecting to the Bulk Electric System~~.
10. Provide~~s~~ reactive resources to Transmission Operators.
11. Revise~~s~~ ~~t~~Transmission maintenance plans as requested by a Transmission Operator or the Reliability Coordinator.

[26] Definition of Transmission Owner from the NERC Glossary of Terms (as of May 15, 2016).

Distribution and Distribution Provider

Distribution

Tasks

1. Provide and operate electrical delivery ~~f~~Facilities between the ~~t~~Transmission system and the ~~E~~end-use ~~C~~customer or distribution-connected energy resource.
2. Identify and characterize its connected load and energy resources.
3. ~~2.~~Implement voltage reduction.
4. ~~3.~~Design and maintain protective relaying systems, under-frequency load-shedding systems, under-voltage load-shedding systems, and Remedial Action Schemes~~Special Protection Systems~~ that interface with the ~~t~~Transmission system.
5. ~~4.~~Provide and implement load-shed capability.
6. ~~5.~~Maintain voltage and power factor within specified limits at the interconnection point.
7. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
8. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Distribution Provider

Definition

The functional entity that provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.[27] ~~The functional entity that provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.~~

Introduction to the Distribution Provider

The Distribution Provider delivers ~~e~~Electrical ~~e~~Energy ~~to the End-use Customer~~ from the ~~t~~Transmission system to the ~~E~~end-use ~~C~~customer. ~~For those End-use Customers who are served at transmission voltages, the Transmission Owner may also serve as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.~~ The Distribution Provider provides the switches and re-closers that could be used to shed load for ~~e~~Emergency action.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinate~~s~~ with Transmission Planners on interconnected load and energy resources to support ~~t~~Transmission analysis~~expansion~~.
2. Coordinate~~s~~ ~~s~~System restoration plans with Transmission Operator.
3. Coordinate~~s~~ with ~~E~~end-use ~~C~~customers, distributed energy resources, and Load-Serving Entities to identify new ~~f~~Facility connection needs.
4. Develop interconnection agreements with Transmission Owners on a ~~f~~Facility basis.
5. Provide~~s~~ operational data to Transmission Operator.
6. Coordinate with Load-Serving Entities to identify critical loads that are to be precluded from load-shedding where avoidable.
7. Provide protective relaying systems, under-frequency load-shedding systems, under-voltage load-shedding systems, and Remedial Action Schemes as defined by the Transmission Planner and Planning Coordinator.

Real-time

8. Obtain voltage and power factor requirements from the Transmission Operator.

~~6.~~9. Implement~~s~~ voltage reduction and shed~~s~~ load as directed by the Transmission Operator or Balancing Authority.

~~7.~~10. Implement~~s~~ ~~s~~System restoration plans as coordinated by the Transmission Operator.

~~8.~~11. Direct~~s~~ Load-Serving Entities to communicate requests for voluntary load ~~c~~Curtailment.

[27] Definition of Distribution Provider from the NERC Glossary of Terms (as of May 15, 2016).

Generator Operation and Generator Operator

Generator Operation

Tasks

1. Formulate daily generation plan.
2. Report operating and availability status of generator Facility(ies) ~~units~~ and related equipment, such as automatic voltage regulator~~s~~ equipment, power system stabilizer equipment and frequency regulating equipment.
3. Operate generator~~s~~ Facility(ies) to provide ~~r~~Real Power and ~~r~~Reactive ~~p~~Power or Interconnected Operations Services ~~reliability-related services~~ in accordance with ~~per~~ contracts or arrangements.
4. Monitor the status of generator~~ing~~ ~~f~~Facility(ies).
5. Support Interconnection frequency and voltage.
6. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
7. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Generator Operator

Definition

The ~~functional~~ entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services~~reliability related services~~.[28]

Relationships with Other Functional Entities

Ahead of Time

1. Provide~~s~~ generation commitment plans to the Balancing Authority.
2. Provide~~s~~ Balancing Authority and Transmission Operators with requested amount of Interconnected Operations Services (IOS)~~reliability-related services~~.
3. Provide~~s~~ availability and operating ~~and availability~~ status of generator~~ing~~ ~~units~~ Facility(ies), to Reliability Coordinator, Balancing Authority and Transmission Operators for reliability analysis.
4. Report~~s~~ status of automatic voltage regulating equipment and power system stabilizer equipment ~~or frequency regulating equipment to~~ Transmission Operators.
5. Report on frequency regulating equipment to Balancing Authority.
6. Provide~~s~~ operational data to Reliability Coordinator, Balancing Authority and Transmission Operator.
7. ~~Receives reliability analyses from Reliability Coordinator.~~
8. Receive~~s~~ notice from Purchasing-Selling Entity if Arranged Interchange approved or denied.
9. Receive~~s~~ reliability alerts from Reliability Coordinator.
10. Receive~~s~~ notification of ~~t~~Transmission system problems from Transmission Operators.

Real-time

11. Provide~~s~~ Real-time operating information to the Transmission Operators and the required Balancing Authority.
12. Adjust~~s~~ ~~r~~Real Power and ~~r~~Reactive ~~p~~Power as directed by the Balancing Authority and Transmission Operators.

[28] Definition of Generator Operator from the NERC Glossary of Terms (as of May 15, 2016).

Generator Ownership and Generator Owner

Generator Ownership

Tasks

1. Establishes generatiorng facilities Facility rRatings, limits, and operating requirements.
2. Designs and authorizes maintenance of the generatiorn plant protective relaying systems, protective relaying systems on the tTransmission lines connecting the generatiorn plant to the tTransmission system, and Remedial Action Schemes (RAS)Special Protection Systems related to the generator.
3. Performs or authorizes Maintains maintenance of owned generatoring fFacilities.
4. Provides verified generatiorng fFacility performance characteristics / data.
5. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
6. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Generator Owner

Definition

The ~~functional~~ entity that owns and maintains generating Facility(ies)~~units~~.[29]

Relationships with Other Functional Entities

Ahead of Time

1. Provide~~s~~ generator Facility(ies) information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and Resource Planner.
2. Provide~~s~~ generator Facility(ies) ~~unit~~ maintenance schedules and generator Facility(ies) ~~unit~~ retirement plans to the Reliability Coordinator, Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner.
3. Develop~~s~~ ~~an~~ interconnection ~~a~~Agreement(s) with Transmission Owner on a ~~f~~Facility basis.
4. Receive~~s~~ approval or denial of ~~t~~Transmission ~~s~~Service request from Transmission Service Provider.
5. Provide~~s~~ Interconnected Operations Services ~~reliability related services~~ to Purchasing-Selling Entity pursuant to agreement.

~~6. Reports the annual maintenance plan to the Reliability Coordinator, Balancing Authority and Transmission Operator.~~

6. Revise~~s~~ the generator~~ion~~ maintenance plans as requested by the Balancing Authority, Transmission Operator, and Reliability Coordinator.
7. Submit Request for Interchange to the Interchange Coordinator.
8. Submit approval for original or revised Arranged Interchange to the Interchange Coordinator.
~~7.~~9. Receive communication that Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.

Real-time

10. Receive Confirmed Interchange Interruptions status from the Interchange Coordinator.
~~8.~~11. Receive Confirmed Interchange revisions (including Curtailments) from the Interchange Coordinator.

[29] Definition of Generator Owner from the NERC Glossary of Terms (as of May 15, 2016).

Purchasinge-Selling and Purchasinge-Selling Entity

Purchasinge-Selling

Tasks

1. Purchase and sell energy or capacity.
2. Arrange for ~~t~~Transmission ~~s~~Service that is required to implement an Interchange Transaction~~by tariffs~~.
3. Request implementation of Arranged Interchange.

Purchasinge-Selling Entity

Definition

The ~~functional~~ entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services~~reliability related services~~. Purchase-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.[30]

Relationships with Other Functional Entities

Ahead of Time

1. Arrange for energy and capacity from Generator Owners.
2. Arrange~~s~~ for ~~t~~Transmission ~~s~~Service from Transmission Service Providers and makes arrangements for self-provided Interconnected Operations Services ~~reliability-related services~~ with Generator Owners or Load-Serving Entities.
3. Submit~~s~~ Requests For Interchange to Interchange Coordinators.

~~3.~~4. Submit approval for original or revised Arranged Interchange to Interchange Coordinator.

~~4. Notifies Generator Operators and Load-Serving Entities if Arranged Interchange requests are approved or denied.~~

5. Receive~~s~~ communication that ~~final approval or denial of~~ Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.
6. Receive~~s~~ ~~load~~ Demand profiles and forecasts from Load-Serving Entities.

Real-time

7. Receive notice of Confirmed Interchange Interruptions from Interchange Coordinator.
8. Receive notice of Confirmed Interchange revisions (including Curtailments) from Interchange Coordinator.

~~7.~~9. Notify~~ies~~ Interchange Coordinators of Confirmed Interchange and Implemented Interchange cancellations or terminations.

~~8.~~10. Receive~~s~~ notice of Confirmed Interchange ~~c~~Curtailments from Interchange Coordinator.

[30] Definition of Purchasing-Selling Entity from the NERC Glossary of Terms (as of May 15, 2016).

Load-Serving and Load-Serving Entity

Load-Serving

Tasks

1. Collect individual load profiles and characteristics.
2. Identify capability for and communicate requests for voluntary load ~~c~~Curtailment.
3. Identify and communicate ~~Participate in under-frequency load shedding systems and under-voltage load shedding systems through identification of~~ critical customer loads that are to be excluded from the load-shedding systems.
4. Identify the resources needed for ~~facilities and provide capability of~~ self-provided Interconnected Operations Services (IOS) ~~reliability-related services for its load~~.
5. Develop overall load profiles and forecasts of end-user energy requirements.
6. Acquire necessary ~~t~~Transmission ~~s~~Service, and provide for Interconnected Operations Services~~reliability-related services~~.
7. Arrange for ~~Submits Requests For~~ Interchange ~~to Interchange Coordinators.~~
8. Manage resource portfolios to meet ~~demand~~ Demand and energy delivery requirements. ~~of End-use Customers.~~

Load-Serving Entity

Definition

~~The functional entity that~~ ~~secures~~ Secures energy and ~~t~~Transmission ~~s~~Service (and Interconnected Operations Services)~~reliability related services)~~ to serve the electrical demand and energy requirements of its end~~-~~use customers.[31]

Relationships with Other Functional Entities

Ahead of Time

1. Submit~~s~~ load data ~~profiles and characteristics, plans, and forecasts~~ as needed to the appropriate entity (*e.g.,* ~~-~~Balancing Authorities, ~~Purchasing-Selling Entities, Planning Coordinator,~~ and Resource Planners, and Transmission ~~Planners~~Service Provider) in accordance with applicable tariffs, interconnection agreements or other arrangements.
2. Coordinate with Distribution Provider to identify critical loads that are to be excluded from load-shedding. ~~Identifies new facility connection needs for End-use Customers.~~
3. Provides generation commitments and dispatch schedules to the Balancing Authority.
4. Provide~~s~~ information regarding~~as to~~ self-provided Interconnected Operations Services (IOS) ~~reliability-related services~~ to the Balancing Authority.
5. Provide~~s~~ necessary data ~~planned purchases~~ to the Resource Planner and Transmission Planner for ~~s~~System modeling and reliability evaluation.
6. Arrange~~s~~ for ~~t~~Transmission ~~s~~Service from Transmission Service Providers and makes arrangements for Ancillary Services ~~reliability-related services~~ with Generator Owners or Load-Serving Entities.
7. Submit~~s~~ Requests For Interchange to Interchange Coordinator~~s~~.

~~7.~~8. Submit approval for original or revised Arranged Interchange to Interchange Coordinator.

9. Receive communication that Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.

~~8.~~10. Notify~~ies~~ Generator Operators if Arranged Interchange requests are approved or denied.

~~9. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.~~

~~10.~~11. Coordinate~~s~~ with Distribution Provider on identifying new ~~f~~Facility interconnection needs.

~~10. Receives notification from Purchasing-Selling Entity if Arranged Interchange requests approved or denied.~~

Real-time

~~11.~~12. Receive~~s~~ requests from the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider ~~-~~for voluntary load ~~c~~Curtailment.

~~12.~~13. Communicate requests for voluntary load ~~c~~Curtailment to end-use customers as directed by the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider.

[31] Definition of Load-Serving Entity from the NERC Glossary of Terms (as of May 15, 2016).

~~13. Notifies Interchange Coordinators of Confirmed Interchange cancellations or terminations.~~

14. Receive~~s~~ notice of Confirmed Interchange revisions (including ~~c~~Curtailments) from Interchange Coordinator.

~~14.~~15. Receive notice of Confirmed Interchange Interruptions from Interchange Coordinator.

Section IV: Version History

[This section will be completed prior to seeking final approval from the Standards Committee.]

Comment Report

Project Name:	Cost Effectiveness Pilot 2016
Comment Period Start Date:	4/27/2016
Comment Period End Date:	5/26/2016
Associated Ballots:	

There were 47 sets of responses, including comments from approximately 47 different people from approximately 46 companies representing 9 of the Industry Segments as shown in the table on the following pages.

Questions

1. Reliability Standard TPL-001-4 requires an entity to consider planned maintenance outages greater than six months in duration in its studies. What, if any, risk is there to the reliable operation of the Bulk Power System (BPS), as defined in Section 215 of the Federal Power Act (i.e., "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 . . . or unanticipated failure of system elements") if planned maintenance outages of less than six months in duration are not considered in studies during one or both seasonal off-peak periods?

Please explain your response:

1a. If there are risks to the reliable operation of the BPS, are the likelihood of the occurrence of these risks low, medium or high?

Please explain your response:

1b. What costs should be considered when evaluating these risks or in adding planned maintenance outages less than six months to TPL-001-4?

Please explain your response:

1c. If you identified one or more risks and identified a likelihood of "medium" or "high", is there a more cost effective manner to reduce them rather than revising TPL-001-4 or is there an preferred approach to revising TPL-001-4 that takes into consideration cost effectiveness?

Please explain your response including descriptions of potential cost effective solutions and the associated benefits to reliability:

2. What, if any, risk to the reliable operation of the BPS, as defined under Section 215 (see question 1 above) is there if an entity does not perform stability analyses for the P0, P1 and P2 categories in TPL-001-4 that consider the possible unavailability of long lead-time equipment?

Please explain your response:

2a. If there are risks to the reliable operation of the BPS, are the likelihood of the occurrence of these risks low, medium or high?

Please explain your response:

2b. What costs should be considered when evaluating these risks?

Please explain your response:

2c. If you identified one or more risks and identified a likelihood of "medium" or "high" is there a cost effective manner to reduce them rather than revising TPL-001-4 or is there an preferred approach to revising TPL-001-4 that takes into consideration cost effectiveness?

Please explain your response including descriptions of potential cost effective solutions and the associated benefits to reliability:

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
					Chip Koloini	Golden Spread Electric Cooperative, Inc.	5	SPP RE
					Ellen Watkins	Sunflower Electric Power Corporation	1	SPP RE
Florida Municipal Power Agency	Chris Gowder	3,4,5,6	FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utility Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC

					Stan Rzad	Keys Energy Services	4	FRCC
					Matt Culverhouse	City of Bartow	3	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steve Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Mark Brown	City of Winter Park	4	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	9	FRCC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
SERC Reliability Corporation	David Greene	10	SERC	SERC PSS	Shih-Min Hsu	Southern Company Services – Transmission	1	SERC
					John Sullivan	Ameren	1	SERC
					Phil Kleckley	SCE&G	1	SERC
					Jeffrey L. Powell	TVA	1	SERC
					David Greene	SERC	10	SERC
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC

Electric Reliability Council of Texas, Inc.	Elizabeth Axson	2		IRC Standards Review Committee	Elizabeth Axson	ERCOT	2	Texas RE
					Charles Yeung	SPP	2	SPP RE
					Ben Li	IESO	2	NPCC
					Ali Miremadi	CAISO	2	WECC
					Mark Holman	PJM	2	RF
					Matt Goldberg	ISO-NE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Dana Wheelock	Seattle City Light	3	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,3,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
Con Ed - Consolidated Edison Co. of New York	Kelly Silver	1,3,5,6	NPCC	Con Edison	Kelly Dash	Con Edison	1,3,5,6	NPCC
					Edward Bedder	Orange and Rockland Utilities	NA - Not Applicable	NPCC
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Robert Schaffeld	Southern Company Services, Inc	1	SERC
					John Ciza	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
PPL -	Robert Tallman	3,5,6	SERC	LG&E and KU	Bob Tallman	LG&E and KU	3,5,6	SERC

Louisville Gas and Electric Co.				Energy		Energy		
					Charlie Freibert	LG&E and KU Energy	3	SERC
					Dan Wilson	LG&E and KU Energy	5	SERC
					Linn Oelker	LG&E and KU Energy	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC No Dominion, Con-Ed and NextEra	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Rob Vance	New Brunswick Power	1	NPCC
					Mark J. Kenny	Eversource Energy	1	NPCC
					Gregory A. Campoli	NY-ISO	2	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Kathleen	ISO-NE	2	NPCC

					Goodman			
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Brian Shanahan	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jason Smith	Southwest Power Pool Inc	2	SPP RE
					James Nail	Independence Power and Light	3,5	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Ellen Watkins	Sunflower Electric Power Corporation	1	SPP RE
					kevin Giles	Westar Energy	1,3,5,6	SPP RE
					Carl Stelly	Southwest Power Pool Inc	2	SPP RE
					John Allen	City Utilities of Springfield	1,4	SPP RE

1. Reliability Standard TPL-001-4 requires an entity to consider planned maintenance outages greater than six months in duration in its studies. What, if any, risk is there to the reliable operation of the Bulk Power System (BPS), as defined in Section 215 of the Federal Power Act (i.e., "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 . . . or unanticipated failure of system elements") if planned maintenance outages of less than six months in duration are not considered in studies during one or both seasonal off-peak periods?

Please explain your response:

Bob Case - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

Black Hills believes it is pretty thorough in its outage coordination studies, so TPL-001-4 does not need to consider outages less than six months. Also, for compliance purposes, we need to identify a "planning horizon" and an "operating horizon." It is not reasonable to keep shortening the planning horizon because it forces transmission planners to lose focus on the longer term horizon.

The planning horizon is year 1 through year 10. Year 1 begins 12 months out from today, generally. We do not study anything in Year 0. To date, we have not had any planned outages of any duration scheduled more than 12 months out, which is confirmed by our outage coordinator and included in the TPL RSAW as evidence. We believe that any outages that do meet this criteria would be addressed in a project specific study as needed, rather than the catch-all TPL study. If it was included in the TPL study, it would be to satisfy a compliance requirement rather than for internal reliability reasons. There is enough uncertainty outside the 12 month operating horizon that any planning horizon analysis of planned outages would be of limited value. Black Hills believes that value would predominately lie in the outage coordination arena.

Likes 0	
Dislikes 0	

Response

Diana McMahon - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

There is no risk to the reliable operation of the BPS if planned outages of less than six months are not considered during TPL-001-4 studies. Current practices require that operational studies be performed to ensure system reliability when taking maintenance outages. These studies include single and credible multiple contingencies, and identifying operational solutions for any violations seen before taking the outage. These operational studies are done with ample time to respond to issues identified.

Likes 0	
Dislikes 0	

Response
Marsha Morgan - 1,3,5,6 - SERC, Group Name Southern Company
Answer
Document Name
Comment
The six month time frame for including planned outages was intentionally chosen by the TPL Standard Drafting Team to be the correct time frame to make sure that outages which can cover critical peak seasons would be included in the planning analysis. Outages shorter than this are not likely to occur over critical peak seasons. Furthermore, within Southern Company, all planned outages are studied by the Operations Planning Department. They will take the necessary steps to operate around an outage. There is no risk to the reliability of the grid if planned outages are not studied (by the Transmission Planner) in planning assessments because the outages are studied by Operations Planning.
Likes 0
Dislikes 0
Response
Thomas Foltz - 3,5
Answer
Document Name
Comment
AEP considers the risk to be minimal. At present, our Operations team (in conjunction with applicable RCs) addresses these short duration issues in both real time and seasonal analysis. It would be impractical to address short duration maintenance outages as part of long term planning and modeling. As a result, we do not believe there is a risk-based need to adjust the threshold to less than six months in system models.
Likes 0
Dislikes 0
Response
Justin Mosiman - 1,3,5,6 - WECC
Answer
Document Name
Comment
There is low risk to the reliable operation of the BPS if planned maintenance outages of less than six months in duration are not considered in planning

studies. Short-term maintenance outages are usually done during off-peak periods and are already evaluated for reliable operation of the BPS through operational studies. Maintenance outages are performed in the operations time frame and are allowed, or not based on operating conditions expected at the time of the outage. Based on operational studies, maintenance outages may be rescheduled to a timeframe that has less impact on BPS performance. BPA's position is this change should not be added to the TPL-001-4 study requirements.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - 10

Answer	
Document Name	

Comment

If planned maintenance outages of less than six months in duration are not considered in studies, the biggest risk would be delayed projects and maintenance due to outage request rejections in the operations horizon. Modeling these outages in planning cases would allow the Transmission Planner (TP) to identify issues that may cause an outage request to be rejected by the RC in order to resolve any scheduling of potential reliability conflicts in the operations horizon.

An additional risk is present if a shorter term outage is not studied that has significant impact on the grid. Without proper study efforts the impact will be realized in real-time or the project will be delayed as mentioned above (which causes changes in other planned outages).

Likes 0	
Dislikes 0	

Response

Daniela Hammons - 1 - Texas RE

Answer	
Document Name	

Comment

See response to 1a.

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	

The only risk would be if there were multiple concurrent outages that had not been studied before. However, short term outage planning is studied in the Operational Horizon. For example, TOP-004-2 ensures that system instability does not occur as a result of the most severe single contingency. For multiple planned outages, special studies are conducted to determine revised System Operating Limits, which are posted on the OASIS via a Temporary Operating Instruction. TPL-001-4 does not need to be modified to cover planned maintenance outages less than six months in duration.

Likes 0	
Dislikes 0	
Response	

Emily Rousseau - 1,2,3,4,5,6 - MRO	
Answer	
Document Name	
Comment	

Removing the six-month TPL-001-4 planning assessment threshold is not cost effective and the FERC directive in paragraph 40 of Order No. 786 http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/E-2 Transmission Planning Rel. Strd.pdf relating to TPL -0 due to unintended impacts of removing the six-month threshold.

The MRO NSRF suggests an equally effective alternative be proposed to address FERC's concerns about off-peak conditions. The MRO NSRF suggests that existing wording in the NERC standard be identified or clarified to include outages of more than six-months should include a sensitivity analysis if the outage occurs in the spring and / or fall months.

Planned maintenance outages of less than six months in duration aren't necessary for long-term annual planning assessments such as TPL-001-4. The annual TPL-001-4 assessments which look in the near-term (years 1 – 5) and long-term (years 6 – 10) planning horizons are reasonable projections of system conditions and aren't meant to represent the specific operational type concerns for outages shorter than six months. Risk is based on probability, duration, and severity. The probability and duration of outages less than six months reduces the chance of an event towards zero as the duration gets smaller. Therefore, the industry reviewed and approved six month duration threshold is appropriate for a planning assessment.

By removing the six month threshold, FERC opens the door to annual TPL-001-4 planning assessments being performed for one day outages such as those required for mandated PRC-005-2 relay and maintenance testing. Short term outages are considered in operational planning assessments such as seasonal, next-day, and current-day assessments.

Annual Planning Assessments are not operational assessments. In short, annual planning assessments become meaningless as durations become shorter than six months. An annual TPL-001-4 planning assessment represents a reasonable general snapshot of the system assuming all equipment is available and in-service except for the specific contingency performed. Daily operational conditions almost never have the system entirely intact and available due to necessary system maintenance and testing.

Likes 0	

Dislikes 0	
Response	
Joe Tarantino - 1,3,4,5,6 - WECC	
Answer	
Document Name	
Comment	
Sacramento Municipal Utility District (SMUD) views the condition of not considering maintenance outages less than 6-months duration does not pose any risk to the bulk power system. Our planned maintenance outages are only scheduled during off-peak conditions; conditions of which transmission planning evaluations consistently have demonstrated no negative impact to the immediate and neighboring bulk power system.	
Likes 0	
Dislikes 0	
Response	
Yvonne McMackin - 1,4,5	
Answer	
Document Name	
Comment	
All planned outages have been studied by the District's system engineer prior to the submittal to Peak RC using the Coordinated Outage System. The outages will then be included in the next day studies. If violations are found in the studies, a mitigation plan will be included in the report before the outage was taken to ensure there are no reliability issues during the outage.	
Likes 0	
Dislikes 0	
Response	
Kelly Silver - 1,3,5,6, Group Name Con Edison	
Answer	
Document Name	
Comment	
The inclusion of planned outages of less than six months in duration in planning studies is not appropriate. TPL-001-4 already requires Transmission Planners to consider planned maintenance outages greater than six months in duration. These kind of short-term planning outages are more	

appropriate in the Operations timeframe—that's where the risk may be. There is no risk in not including these short-term planned outages in the Planning timeframe.

Likes 0	
Dislikes 0	

Response

David Greene - 10, Group Name SERC PSS

Answer	
Document Name	

Comment

With the various categories of contingencies which need to be considered already as part of system assessment work related to compliance with Reliability Standard TPL-001-4, both single and multiple element contingencies, to further give consideration to outages of less than 6 months duration would appear to be needlessly redundant. The six month time frame for including planned outages was intentionally chosen by the TPL Standard Drafting Team to be the correct time frame to make sure that outages which can cover critical peak seasons would be included in the planning analysis. Outages shorter than this are not likely to occur over critical peak seasons. Furthermore, all planned outages are studied by the Operations Planning Department. They will take the necessary steps to operate around an outage. There is no risk to the reliability of the grid if planned outages are not studied (by the Transmission Planner) in planning assessments because the outages are studied by Operations Planning.

Some additional points to consider:

- The purpose of the standard TPL-001-4 is to "Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". Outages that would be scheduled in the planning horizon would be subject to the performance requirements of this standard. Outages that would be scheduled in the operating horizon should be subject to the performance requirements of other standards.
- Planned maintenance and construction outages typically last from a few days to a few weeks and occur during off-peak time periods with load levels ranging from light load to shoulder peak.
- During the construction and maintenance seasons multiple facilities are out of service at the same time and are studied in the operating horizon.
- System adjustments, including transmission switching and generation redispatch (develop short term operating guides), are made as needed to accommodate planned maintenance and construction outages.

Likes 0	
Dislikes 0	

Response

Glenn Pressler - 1,3,5

Answer	
Document Name	

Comment

No risk, short duration outages are effectively studied and addressed in the operating horizon. Year 1 (NERC definition) of the planning cases is anywhere from 12 - 18 months from the time the outage will actually occur. Mitigating for a short-duration outage that is beyond one year from occurrence is an ineffective use of time as system conditions will not be as well-known as they are within the one year or less timeframe that operations studies are performed

Likes 0	
Dislikes 0	

Response

Laura Nelson - 1

Answer	
Document Name	

Comment

Planned maintenance of less than six months are captured during operational planning study work and as such result in minimal risk if not considered during the TPL-001-4 assessment work.

Planned maintenance outages greater than six months generally would involve large projects and/or significant changes to the system for which a planning assessment (TPL work) is justified. Shorter window planned maintenance outages have in general less impact to the system and can be managed by the operational planning process as they move into the operating horizon.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	
Document Name	

Comment

The only minor risk lies in relying on operations studies to cover any planned maintenance outages of less than six months in duration. This results in less time to develop mitigation plans, if required, for the planned outages.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - 6

Answer	
Document Name	

Comment

Risk to the reliable operation of the BPS if planned maintenance outages less than six months in duration are not considered is minimal, as these short term outages are already evaluated through operational assessments near-term operations horizon.

Planned maintenance outages of less than six months in duration aren't necessary for long-term annual planning assessments such as TPL-001-4. The annual TPL-001-4 assessments which look in the near-term (years 1 – 5) and long-term (years 6 – 10) planning horizons are reasonable projections of system conditions and aren't meant to represent the specific operational type concerns for outages shorter than six months. Risk is based on probability, duration, and severity. The probability and duration of outages less than six months reduces the chance of an event towards zero as the duration gets smaller. Therefore, the industry reviewed and approved six month duration threshold is appropriate for a planning assessment.

By removing the six month threshold, FERC opens the door to annual TPL-001-4 planning assessments being performed for one day outages such as those required for mandated PRC-005-2 relay and maintenance testing. Short term outages are considered in operational planning assessments such as seasonal, next-day, and current-day assessments.

Annual Planning Assessments are not operational assessments. In short, annual planning assessments become meaningless as durations become shorter than six months. An annual TPL-001-4 planning assessment represents a reasonable general snapshot of the system assuming all equipment is available and in-service except for the specific contingency performed. Daily operational conditions almost never have the system entirely intact and available due to necessary system maintenance and testing.

With respect to the concern for evaluation of planned maintenance outages in the seasonal off-peak periods, inclusion of a requirement to perform an assessment of the off-peak seasonal case for planned maintenance outages with durations greater than six months in duration, that extend into seasonal off-peak periods, may be appropriate for the TPL planning assessment.

Likes 0	
Dislikes 0	

Response

Colby Bellville - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

Yes, Duke Energy believes that there are some outages less than six months in duration that would have some potential impact on the BPS. However, the impacts mentioned would be low risk and have a minimal impact on the BPS. The justification for low risk/minimal impact in part is based on the practice of Operational Planners being able to mitigate any potential risk to the system by modifying the scheduling of outages, re-configuring of

transmission system, and other real-time actions that could be taken to mitigate risk to the BPS.

Likes 0	
Dislikes 0	

Response

Jason Marshall - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

The New England States Committee on Electricity ("NESCOE") appreciates the opportunity to submit comments. NESCOE is New England's regional state committee. NESCOE understands that ISO New England ("ISO-NE") will be submitting comments today explaining how the New England region is already well positioned to address reliability risks in connection with planned maintenance outages. This includes a suite of authorities and procedures that are currently in place to govern the scheduling and management of planned (and unplanned) outages. Last year, ISO-NE received and managed over 6,000 planned and unplanned outages within New England and in neighboring areas. *ISO New England Transmission Equipment Outage Coordination in 2015*, May 11, 2016, at 4. NESCOE agrees with ISO-NE that, compared to the current administrative processes in place in New England, imposing a new standard that requires planning analyses for known planned outages is an inefficient approach to addressing the relevant reliability risks in New England.

Likes 0	
Dislikes 0	

Response

Terry Bllke - 2

Answer	
Document Name	

Comment

MISO agrees that planned maintenance outages should be considered in planning for the reliable operation of the BPS. If the planning function does not provide for a robust system with sufficient adequacy to allow each facility an opportunity to be removed from service for planned maintenance during periods when maintenance is typically performed (off-peak) and while simultaneously allowing the system to be operated in a manner that is secure for N-1 contingencies during the planned outage, the RC outage coordination process could be backed into a corner where they are unable to confidently approve certain maintenance outage requests. Given that a core purpose of planning is to ensure the system is adequate, reliable and robust under future conditions, the need for performing future maintenance of facilities cannot be ignored. However, including only scheduled outages with a 6 month duration or longer will not meet the objective of ensuring the system is adequate to accommodate future maintenance, as this method will not verify that the system will support maintenance of each facility where that facility is required to be removed from service. Therefore, the standard should be revised to remove the 6 month planned outage requirement and instead reinstate the provisions in the previous TPL standard where off-peak planning cases are analyzed to ensure the system is capable of supporting a planned outage for each element of the system while simultaneously being secure for the next contingency.

Likes 0	
Dislikes 0	
Response	
Bob Thomas - 4	
Answer	
Document Name	
Comment	

Illinois Municipal Electric Agency (IMEA) does not have the asset ownership or operational experience to provide a critique of the cost effectiveness pilot questions. IMEA encourages NERC to consider a cost effectiveness pilot relevant to smaller entities. Also, IMEA was surprised NERC's 5/2/16 Cost-Effectiveness WebEx did not address the cost impact and cost effectiveness analysis processes being employed by NERC. IMEA recommends that NERC provide a WebEx addressing the established industry best practices being used by NERC for conducting cost impact and cost effectiveness analyses to support the development and adoption of risk-/results-based reliability standards.

Likes 0	
Dislikes 0	
Response	
David Jendras - 1,3,6	
Answer	
Document Name	
Comment	

With the various categories of contingencies which need to be considered already as part of system assessment work related to compliance with Reliability Standard TPL-001-4, both single and multiple element contingencies, to further give consideration to outages of less than 6 months duration would appear to be needlessly redundant.

Some additional points to consider:

- **The purpose of the standard TPL-001-4 is to "Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". Outages that would be scheduled in the planning horizon would be subject to the performance requirements of this standard. Outages that would be scheduled in the operating horizon should be subject to the performance requirements of other standards.**

- **Planned maintenance and construction outages typically last from a few days to a few weeks and occur during off-peak time periods with load levels ranging from light load to shoulder peak. Although practices on other systems may vary, there are no maintenance outages on the Ameren system that would last up to six months.**

- **During the construction and maintenance seasons multiple facilities are out of service at the same time and are studied in the**

operating horizon.

- **System adjustments, including transmission switching and generation redispatch (develop short term operating guides), are made as needed to accommodate planned maintenance and construction outages.**

Likes 0	
Dislikes 0	

Response

Oliver Burke - 1,5

Answer	
Document Name	

Comment

1. While maintenance outages of less than 6 months are not explicitly evaluated in long-term planning studies, they are implicitly reviewed in planning events which simulate the unplanned outages of multiple facilities. Thus entities have the opportunity to identify potential reliability risks observed in various system conditions (peak, off-peak, and sensitivities) as if one facility were out for a planned outage and a second unplanned outage occurred. Additionally, short-term planned outages can be scheduled and thus can be planned to occur during conditions where reliability risk is de minimis. The planning of routine short-term outages is best done in the operating horizon where better estimates of upcoming real-time conditions can be used in the evaluations.

Likes 0	
Dislikes 0	

Response

larry brusseau - 1

Answer	
Document Name	

Comment

Removing the six-month TPL-001-4 planning assessment threshold is not cost effective and the FERC directive in paragraph 40 of Order No. 786[1] relating to TPL-001-4 threshold should not be implemented due to unintended

The MRO NSRF suggested an equally effective alternative be proposed to address FERC's concerns about off-peak conditions. The MRO NSRF suggested that existing wording in the NERC standard be identified or clarified to include outages of more than six-months should include a sensitivity analysis if the outage occurs in the spring and / or fall months.

Planned maintenance outages of less than six months in duration aren't necessary for long-term annual planning assessments such as TPL-001-4. The

annual TPL-001-4 assessments which look in the near-term (years 1 – 5) and long-term (years 6 – 10) planning horizons are reasonable projections of system conditions and aren't meant to represent the specific operational type concerns for outages shorter than six months. Risk is based on probability, duration, and severity. The probability and duration of outages less than six months reduces the chance of an event towards zero as the duration gets smaller. Therefore, the industry reviewed and approved six month duration threshold is appropriate for a planning assessment.

By removing the six month threshold, FERC opens the door to annual TPL-001-4 planning assessments being performed for one day outages such as those required for mandated PRC-005-2 relay and maintenance testing. Short term outages are considered in operational planning assessments such as seasonal, next-day, and current-day assessments.

Annual Planning Assessments are not operational assessments. In short, annual planning assessments become meaningless as durations become shorter than six months. An annual TPL-001-4 planning assessment represents a reasonable general snapshot of the system assuming all equipment is available and in-service except for the specific contingency performed. Daily operational conditions almost never have the system entirely intact and available due to necessary system maintenance and testing.

Likes 0	
Dislikes 0	

Response

Hien Ho - 1,3,4,5,6

Answer	
Document Name	

Comment

1. No risks. Planned maintenance outages of less than six months in duration will be studies and coordinated per TOP standards. We believe that the operation environment is more suited to these outages than including them into the TPL standard. Throughout WECC, owners have a financial incentive to coordinate outages at appropriate times of year. Typically outage scheduling for major equipment is based on a combination of looking at historical system conditions and by having ongoing discussions with potentially affected entities operations departments. This type of operational coordination happens multiple times throughout the year instead of the once per year TPL study. If FERC/NERC determines additional outages must be modeled, certain subsets may more cost effective than modeling all outages. The subset could be EHV facilities, CIP Medium Impact Facilities or the Facilities specified in PRC-023 R1-R5.

Likes 0	
Dislikes 0	

Response

John Pearson - 2 - NPCC

Answer	
Document Name	

Comment

ISO-NE agrees with the Commission's concern that registered entities should have the capability and authority to study the reliability impacts of planned maintenance outages scheduled greater than 12 months in advance of the proposed outage date. ISO-NE does not agree, however, that such outages should be considered in TPL-001-4 studies. Based on ISO-NE's experience, it would not be cost-effective to establish a new requirement in TPL-001-4 to consider such outages, but NERC might consider expanding the application of IRO-017-1 to outages planned outside of Operations Planning Horizon.

By way of context, in New England, Transmission Owners have submitted nearly 50K outage requests since 2008, and Generation owners have submitted nearly 30K requests since 2011, to ISO-NE. ISO-NE's outage coordination process covers outage requests made up to 24 months in advance of the proposed start date. ISO-NE studies the reliability and congestion impacts of proposed outages, and under its process, ISO-NE has the authority to approve, delay or deny the outage depending on whether adverse reliability or economic impacts would otherwise occur.

In the timeframes noted above, ISO-NE has therefore assessed the reliability and congestion impacts of tens of thousands of transmission and generation outage requests – for about 1500 of those, the TO or GO submitted the request over 12 months in advance of the proposed outage date. In administering its program, ISO-NE has avoided adverse reliability impacts that would have resulted from the transmission or generation element being removed from service on the schedule that was initially proposed. And, ISO-NE's repositioning of outages has saved consumers approximately $200M over the last 10 years. For more details, see ISO-NE's *Annual Report on Outage Coordination* at http://www.iso-ne.com/static-assets/documents/2016/05/2015-isone-transmission-equipment-outage-coordination.pdf

Adding a requirement to study planned maintenance outages as part of the TPL assessment is therefore an unnecessary added burden. ISO-NE already accomplishes the same purpose through its Outage Coordination program. If NERC and FERC have a concern that some registered entities are not assessing the reliability impacts of planned maintenance outages that are being scheduled over 12 months in advance with less than 180 day duration, Reliability Standard IRO-017-1 (going into effect 4/1/17) could be modified to require the RC, BA and TOP to assess planned maintenance outages in the Near-Term Transmission Planning Horizon in addition to the Operations Planning Horizon.

Addressing reliability risks associated with planned maintenance will be cost-effective through an Outage Coordination program, such as the one administered by ISO-NE (and as contemplated by IRO-017-1). This approach also avoids disruption to the long-term system planning assessment under TPL-001-4 for several reasons, including:

- The iterative process of scheduling and approving outages requires a high degree of communication and coordination up to and including Real-time. Operations personnel have developed the experience, tools, procedures and process needed to manage and minimize reliability and economic impacts associated with planned outages. IRO-017-1 requires the development of a process, communication and resolution of identified conflicts.

- In contrast, studies under TPL-001-4 are typically done by system engineers doing relatively static studies on a relatively known system, and publishing a needs assessment. Requiring such an assessment under TPL-001-4 would simply be an additional step to what outage coordinators need to do anyway.

In sum, there is no risk to the reliable operation of the Bulk Power System if outages less than six months in duration are not considered in studies associated with TPL-001-4 so long as an outage coordination process is in place. When outages are coordinated (as all relevant registered entities must do under IRO-017-1 starting in April 2017) these registered entities should ensure that the reliability of the BPS is maintained under these conditions. Evaluation of these shorter duration outages in the context of TPL-001-4 is not a meaningful exercise.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - 1,3,5,6 - MRO,WECC,SPP RE

Answer	
Document Name	

Comment

Xcel Energy feels that there is minimal to no risk to the reliable operation of the Bulk Power System by not considering planned maintenance outages of less than six months in duration in the planning horizon studies of TPL-001-4.

Likes 0	
Dislikes 0	

Response

Lauren Price - 1 - MRO,RF

Answer	
Document Name	

Comment

Response: *ATC supports the revision of the TPL-001-4 standard to include the assessment of planned outages (scheduled or future to-be-scheduled outages) that are less than 6 months in duration. ATC further suggests that the revisions give Transmission Planners and Planning Coordinators the flexibility to evaluate areas of their BPS where planned outages may result in a large amount of firm load loss or firm transmission service interruption. These planned outages should only be evaluated for system off peak periods when planned outages would typically be taken.*

Please explain your response: *ATC believes that a properly planned transmission system is one that ensures planned outages for durations of less than 6 months can be accomplished during typically used off-peak conditions without the risk of a large amount of firm load loss or firm transmission service interruption. The subsequent contingencies for the planned outage evaluations would only include the planning event contingencies that do not allow interruption of firm transmission service or non-consequential load loss (e.g. P1, P2.1, P3, and selected EHV contingencies).*

Likes 0	
Dislikes 0	

Response

Lee Maurer - 1

Answer	
Document Name	

Comment	
Oncor Electric Delivery is interested in participating in the "Cost Effectiveness Pilot".	
Likes 0	
Dislikes 0	
Response	
Scott Langston - 1,3,5	
Answer	
Document Name	
Comment	
For the majority of utilities the risk is minimal as these outages are studied in seasonal, next-day and current day studies for operations performed for existing TOP Standards.	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Webb Karen
Dislikes 0	
Response	
Jeremy Voll - 1,3,5,6	
Answer	
Document Name	Cost Effectiveness Pilot Unofficial Comment Form Final Comments_BEPC.docx
Comment	
Removing the six-month TPL-001-4 planning assessment threshold is not cost effective and the FERC directive in paragraph 40 of Order No. 786 relating to TPL -001-4 threshold should not be implemented due to unintended Basin Electric Power Cooperative (BEPC) suggests using the tools that are already in place through the operating realm. These tools would include, but not be limited to seasonal assessments, next day studies (TOP/RC), Real-Time Contingency Analysis , and the market place. The checks and balances are already in place to catch these outages that are less than 6 months and occur during off peak times. Additionally most of these longer term outages are to perform critical maintenance and construction activities. There is always a risk when taking outages, but in some cases the risk is greater to not take the outage. Planned maintenance outages of less than six months in duration aren't necessary for long-term annual planning assessments such as TPL-001-4. The annual TPL-001-4 assessments which look in the near-term (years 1 – 5) and long-term (years 6 – 10) planning horizons are reasonable projections of system conditions and aren't meant to represent the specific operational type concerns for outages shorter than six months. Risk is based on probability, duration, and severity. The probability and duration of outages less than six months reduces the chance of an event towards zero as the duration gets smaller. Therefore, the industry reviewed and approved six month duration threshold is appropriate for a planning assessment. By removing the six month threshold, FERC opens the door to annual TPL-001-4 planning assessments being performed for one day outages such as those required for mandated PRC-005-2 relay and maintenance testing. Short term outages are considered in operational planning assessments such	

as seasonal, next-day, and current-day assessments.

Annual Planning Assessments are not operational assessments. In short, annual planning assessments become meaningless as durations become shorter than six months. An annual TPL-001-4 planning assessment represents a reasonable general snapshot of the system assuming all equipment is available and in-service except for the specific contingency performed. Daily operational conditions almost never have the system entirely intact and available due to necessary system maintenance and testing.

Likes 0	
Dislikes 0	

Response

Jennifer Losacco - 1 - FRCC

Answer	
Document Name	

Comment

Florida Power and Light appreciates NERC developing the cost effectiveness pilot to determine the risks and cost associated with standard changes. In terms of TPL-001-4, the risk is negligible as all major planned outages within the FRCC are studied by Operation Engineers in a seasonal assessment less-than a year out. Outage planning is fundamentally an operating function since entities operate around planned outages, not build to support them. Therefore, outage planning concerns could be better addressed by enhancing the outage planning and coordination process in the TOP standards.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	
Document Name	

Comment

Planned maintenance outages are considered in operational planning studies which assess the reliable operation of the BPS. Multiple contingency studies for off-peak conditions which consider maintenance outages for a single element plus the subsequent unplanned loss of an additional single element are included in TPL-001-4. These studies support system reliability, system maintenance, and operational flexibility. Moreover, additional transmission studies including planned maintenance outages would typically overlap with operational studies. Therefore, TVA sees a low risk to the reliable operation of the BPS if planned maintenance outages of less than six months duration are not considered in TPL-001-4 studies.

Likes 0	
Dislikes 0	

Response
Elizabeth Axson - 2, Group Name IRC Standards Review Committee
Answer	
Document Name	Final_SRC Unofficial_Comment_Form_CEP_042716.docx
Comment
The ISO/RTO Council agrees that planned maintenance outages should be considered in planning for the reliable operation of BPS. However, RCs already take into account requests for planned maintenance outage submitted by entities in their respective RC areas through their outage coordination procedures. RCs presently have the authority to deny any planned maintenance outages that would create reliability risks and thereby mitigate any potential risks resulting from planned maintenance outages in its RC area. Reliability Standard IRO-017-1 – Outage Coordination, effective April 1, 2017, codifies this practice by requiring RCs to establish a generation and transmission outage coordination process. Consequently, there is no risk to the reliable operation of the BPS if planned maintenance outages of less than six months in duration are not considered in planning studies during one or both seasonal off-peak periods under the TPL-001-4 standard. Such a requirement may not be helpful anyway, since a significant number of planned maintenance outages conducted in any given year will not be scheduled or submitted for approval far enough in advance to be incorporated into the planning assessment required under TPL-001-4. *please note CAISO does not join the SRC answer to Question #1
Likes 0	
Dislikes 0	
Response
Douglas Webb - 1,3,5,6 - SPP RE
Answer	
Document Name	
Comment
There is little or no risk to the BPS since planned maintenance outages of less than six months in duration are considered as part of the TOP-002 Standards. In a long range planning study/assessment there might be an exceedance identified for a maintenance outage but, normally, mitigation of that exceedance would take place during near term/real time operational studies. The actual maintenance outage will be impacted/affected more by actual operational conditions than some future set of assumed conditions.
Likes 0	
Dislikes 0	
Response
Oshani Pathirane - 1,3 - NPCC

Answer	
Document Name	
Comment	
Please see response below.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
The intent of NERC Reliability Standard TPL-001-4 is to establish transmission system planning studies, for both near-term and long-term planning horizons, operating over a broad range of system conditions and probable contingencies. These studies are meant to identify projected risks that can be mitigated through near and long-term solutions, such as delaying generator retirements and constructing new transmission facilities, while limiting incremental system changes, such as planned short-term facility outages. The inclusion of these incremental system changes is more appropriate for seasonal operational planning assessments due to the smaller duration studied.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - 1	
Answer	
Document Name	
Comment	
Since P6 events evaluate N-2 contingencies, there appears to be no real risk to not modeling known outages of any duration. Furthermore, on our system, outages are not scheduled more than thirteen months in advance. Therefore, there are no known outages on our system in the planning horizon.	
Likes 0	
Dislikes 0	
Response	

Chris Gowder - 3,4,5,6 - FRCC, Group Name FMPA	
Answer	
Document Name	
Comment	

FMPA initially points out this question mixes several different concepts that are currently handled in different ways. Seasonal studies are not currently required by the TPL-001-4 standard, though some PCs and TPs may be including seasonal cases in their planning horizon cases. The existing reference in TPL-001-4 to outages of a duration greater than 6 months is in R1.1, a set of conditions that apply to all system models used in the assessment. Thus FMPA believes this question should be asked "…if planned maintenance outages of less than 6 months in duration are not considered in studies prepared for annual planning assessments." We note that the concerns raised here include a somewhat "reverse" perspective on the standard requirements. FMPA believes that the TPL-001-4 standard sets the minimum criteria for an entity's Planning Assessment. To say that something is excluded (as worded in the bulleted section above) implies the standard mandates this item not be studied. From FMPA's perspective, there is currently leeway that allows an entity to study any such transmission or generation outage it wishes, and to do so at any level of rigor (via an individual contingency, a sensitivity prepared under R2.1.4., or via a near term of even long term planning horizon study case). The question is, instead, whether the industry is insufficiently studying planned outages of major transmission and generation facilities in the absence of direction to include a minimum level of such studies.

In most cases, FMPA believes there is no risk to the BPS from not considering planned maintenance outages of less than six months in System models used for Planning Assessments. Planned maintenance outages are already studied, not only in the operations horizon, but also further out in time when they are known. Planning horizon System models, including those for Off-Peak periods, are intended to represent projected System conditions for specific scenarios. Mandating inclusion of short duration outages as a variable in creating models could result in far more scenarios than are necessary for an effective Planning Assessment, and would provide little benefit. However, FMPA does believe there are specific scenarios involving planned maintenance outages that could pose a risk to the BPS and warrant special attention. The PC and TP should have the leeway to determine which scenarios should be included in their assessments and NERC should not structure standard Requirements that mandate a specific minimum number, nor that require "all" such scenarios.

Likes 0	
Dislikes 0	
Response	

Bertha Ellen Watkins - 1	
Answer	
Document Name	
Comment	

The intent of NERC Reliability Standard TPL-001-4 is to establish transmission system planning studies, for both near-term and long-term planning horizons, operating over a broad range of system conditions and probable contingencies. These studies are meant to identify projected risks that can be mitigated through near and long-term solutions, such as delaying generator retirements and constructing new transmission facilities, while limiting incremental system changes, such as planned short-term facility outages. The inclusion of these incremental system changes is more appropriate for seasonal operational planning assessments due to the smaller duration studied.

Likes 0	
Dislikes 0	

Response	
Michelle Amarantos - 1,3,5,6	
Answer	
Document Name	
Comment	
AZPS believes this creates little risk in the planning horizon. Any potential issues are best identified through next-day, real time and seasonal analysis studies (in conjunction with applicable RCs) to addresses these short duration issues, rather than through TPL-001-4. These planned maintenance outages tend to be rescheduled, as needed, in the operations horizon to account for present conditions.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No Dominion, Con-Ed and NextEra	
Answer	
Document Name	
Comment	
ISO-NE, one of our member organizations, agrees with the Commission's concern that registered entities should have the capability and authority to study the reliability impacts of planned maintenance outages scheduled greater than 12 months in advance of the proposed outage date. ISO-NE does not agree, however, that such outages should be considered in TPL-001-4 studies. Based on ISO-NE's experience, it would not be cost-effective to establish a new requirement in TPL-001-4 to consider such outages, but NERC might consider expanding the application of IRO-017-1 to outages planned outside of Operations Planning Horizon. By way of context, in New England, Transmission Owners have submitted nearly 50K outage requests since 2008, and Generation owners have submitted nearly 30K requests since 2011, to ISO-NE. ISO-NE's outage coordination process covers outage requests made up to 24 months in advance of the proposed start date. ISO-NE studies the reliability and congestion impacts of proposed outages, and under its process, ISO-NE has the authority to approve, delay or deny the outage depending on whether adverse reliability or economic impacts would otherwise occur. In the timeframes noted above, ISO-NE has therefore assessed the reliability and congestion impacts of tens of thousands of transmission and generation outage requests – for about 1500 of those, the TO or GO submitted the request over 12 months in advance of the proposed outage date. In administering its program, ISO-NE has avoided adverse reliability impacts that would have resulted from the transmission or generation element being removed from service on the schedule that was initially proposed. And, ISO-NE's repositioning of outages has saved consumers approximately $200M over the last 10 years. For more details, see ISO-NE's *Annual Report on Outage Coordination* at http://www.iso-ne.com/static-assets/documents/2016/05/2015-isone-transmission-equipment-outage-coordination.pdf	

Adding a requirement to study planned maintenance outages as part of the TPL assessment is therefore an unnecessary added burden. ISO-NE already accomplishes the same purpose through its Outage Coordination program. If NERC and FERC have a concern that some registered entities are not assessing the reliability impacts of planned maintenance outages that are being scheduled over 12 months in advance with less than 180 day duration, Reliability Standard IRO-017-1 (going into effect 4/1/17) could be modified to require the RC, BA and TOP to assess planned maintenance outages in the Near-Term Transmission Planning Horizon in addition to the Operations Planning Horizon.

Addressing reliability risks associated with planned maintenance will be cost-effective through an Outage Coordination program, such as the one administered by ISO-NE (and as contemplated by IRO-017-1). This approach also avoids disruption to the long-term system planning assessment under TPL-001-4 for several reasons, including:

- The iterative process of scheduling and approving outages requires a high degree of communication and coordination up to and including Real-time. Operations personnel have developed the experience, tools, procedures and process needed to manage and minimize reliability and economic impacts associated with planned outages. IRO-017-1 requires the development of a process, communication and resolution of identified conflicts.
- In contrast, studies under TPL-001-4 are typically done by system engineers doing relatively static studies on a relatively known system, and publishing a needs assessment. Requiring such an assessment under TPL-001-4 would simply be an additional step to what outage coordinators need to do anyway.

In sum, there is no risk to the reliable operation of the Bulk Power System if outages less than six months in duration are not considered in studies associated with TPL-001-4 so long as an outage coordination process is in place. When outages are coordinated (as all relevant registered entities must do under IRO-017-1 starting in April 2017) these registered entities should ensure that the reliability of the BPS is maintained under these conditions. Evaluation of these shorter duration outages in the context of TPL-001-4 is not a meaningful exercise.

Likes 0	
Dislikes 0	

Response

Angela Gaines - 1,3,5,6

Answer	
Document Name	

Comment

Thank you for the opportunity to file comments in the Cost Effectiveness Pilot. At this time PGE does not have the ability to schedule maintenance activities with duration of less than 6 months in the 2 year cases with any degree of accuracy. Planned outages are scheduled for off peak conditions and many are scheduled to not overlap. Developing one case to include all of these outages would be overly conservative. These outages are studied in the Operations Horizon to confirm that there is not risk.

Likes 0	

Dislikes 0	
Response	

1a. If there are risks to the reliable operation of the BPS, are the likelihood of the occurrence of these risks low, medium or high?

Please explain your response:

Glenn Pressler - 1,3,5

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Kelly Silver - 1,3,5,6, Group Name Con Edison

Answer	
Document Name	

Comment

There is no risk to the BPS in the Planning timeframe. The inclusion of planned outages of less than six months in duration in planning studies is not appropriate. TPL-001-4 already requires Transmission Planners to consider planned maintenance outages greater than six months in duration. These kind of short-term planning outages are more appropriate in the Operations timeframe—that's where the risk may be. There is no risk in not including these short-term planned outages in the Planning timeframe.

Likes 0	
Dislikes 0	

Response

Leonard Kula - 2

Answer	
Document Name	

Comment

Generally speaking, there does not appear to be any real risks to the reliable operation of the BPS if outages less than 6 months are not included in planning assessments. These planned outages are normally considered and assessed in operations planning analyses by the Transmission Operator and Reliability Coordinator. As an example, consistent with the recently adopted IRO-017-1 standard, the IESO has policy and procedure in place to ensure planned outages greater than 3 weeks are coordinated and assessed in operations planning time

frame (next day to 1 year in advance). The IESO believes this is the appropriate process to assess outages for which operating measures are either the only means or a more effective means than their system expansion or upgrading counterparts as the latter would only be effective if time would allow for the installation of new facilities or upgrading existing facilities to address the risk (or maintain the required transmission transfer capability).

The most significant drawback of not including such planned outages is perhaps the inaccurate assessment of available transfer capabilities (ATCs) for the beyond 1-year time frame. Not having accurately calculated ATC does not necessarily result in unreliable operation of the BPS since any excessive reservation and use of the transmission will be identified during the interchange implementation phase.

The IESO does not believe that there is any real risk to the reliable operation of the BPS if planned outages of less than 6 months are not included in the TPL-001 standard. In fact, if such outages were included in the TPL-001 standard, they would be redundant with like requirements in the IRO-017-1 standard resulting in additional cost without any real reliability benefits. To cover the timeframe from one year to the time period where sufficient lead time could allow for transmission expansion/upgrading to address performance issues during the planned outages, consideration may be given to extending the time period for outage coordination (in IRO-017-1) where appropriate as an equally effective but less costly alternative.

Likes 0	
Dislikes 0	

Response

Diana McMahon - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

No risks were identified.

Planned outage impacts are studied in the operating horizon to ensure system integrity is maintained in the event of any contingencies as identified in the Regional SOL Methodology. The operating horizon studies have a more accurate depiction of the system (e.g. other planned outages), than any studies performed in a 2-10 year planning analysis.

Likes 0	
Dislikes 0	

Response

Ruida Shu - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No Dominion, Con-Ed and NextEra

Answer	Low
Document Name	

Comment

The reliability risk is extremely small based on ISO-NE’s exercise of outage coordination authority and established process of managing reliability and

economic impacts.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - 1,3,5,6	
Answer	Low
Document Name	
Comment	
These concerns are best covered through other studies in the operations horizon.	
Likes 0	
Dislikes 0	
Response	
Bertha Ellen Watkins - 1	
Answer	Low
Document Name	
Comment	
We believe, when studied under these conditions, the risks to reliable BPS operations are low, as short-term operational planning assessments already address the concern identified by the FERC directive.	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - 3,4,5,6 - FRCC, Group Name FMPA	
Answer	Low
Document Name	
Comment	
Planned maintenance outages in the planning horizon timeframe with the potential to cause impacts to the BPS are infrequent. Most significant impacts will be captured by existing N-1-1 analyses, leaving only a small population of significant outages, most of which can be dealt with in the operating	

horizon.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Low
Document Name	
Comment	
We believe, when studied under these conditions, the risks to reliable BPS operations are low, as short-term operational planning assessments already address the concern identified by the FERC directive.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Low
Document Name	
Comment	
Planned maintenance outages of less than six months in duration aren't necessary for long-term annual planning assessments such as TPL-001-4. The annual TPL-001-4 assessments which look in the near-term (years 1 – 5) and long-term (years 6 – 10) planning horizons are reasonable projections of system conditions and aren't meant to represent the specific operational type concerns for outages shorter than six months. By removing the six month threshold, FERC opens the door to annual TPL-001-4 planning assessments being performed for one day outages. Short term outages are considered in operational planning assessments such as seasonal, next-day, and current-day assessments. Also, we have a concern that the term 'reliable operation' should be capitalized in the question listed above due to the fact that it's a defined term in the NERC Glossary. Additionally, the definition of the term addresses the support of the Bulk Power System (BPS). However if the drafting team has another directions for this term (since it's lower case), we would ask the drafting team to provide some clarity on the intent of the use and direction of the term moving forward.	
Likes 0	
Dislikes 0	
Response	

Oshani Pathirane - 1,3 - NPCC	
Answer	Low
Document Name	
Comment	

The risk to the reliable operation of the BPS - if outages less than 6 months in duration continue to be excluded from planning assessments over the time horizon of 18 months to 20 years - is low.

Over an increasing time horizon, all outage information becomes progressively less complete and less accurate. Yet sufficient capacity must be planned over the long term on the *assumption* of certain durations and magnitudes of anticipated contingencies required. The knowledge of certain planned outages may help validate or support certain outage assumptions, but in and of itself, such knowledge likely does not significantly impact or change the long term planning criteria, particularly over the longer term planning horizon.

Also, such planned outages are normally assessed in Operations Planning Analyses by the Transmission Operator and Reliability Coordinator over the shorter term horizon. As per the recently adopted IRO-017-1 standard, planned outages greater than 3 weeks but less than approximately 6 months in duration are coordinated and assessed within the Operations Planning time frame, such being from the next day to 1 year in advance. Further, if planned outages less than 6 months in duration – those which are planned over the shorter term horizon of less than 1 year - were to be included in TPL-001-4, these would be redundant with requirements in IRO-017-1, thus resulting in additional costs to entities without a significant benefit to reliability.

Likes 0	
Dislikes 0	
Response	
Douglas Webb - 1,3,5,6 - SPP RE	
Answer	Low
Document Name	
Comment	

There is little or no risk to the reliable operation of the BPS since planned maintenance outages of less than six months in duration are considered as part of the TOP-002 Standards.

Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - 2, Group Name IRC Standards Review Committee	
Answer	Low
Document Name	
Comment	

The likelihood of any negative impact to the BPS attributable to not including planned maintenance outages of less than six months in planning studies is low because these impacts are already evaluated through RC outage coordination activities.

The risk to the BPS is low because RCs already study and address these outages through their outage coordination procedures, so they do not need to be considered as part of the planning assessment under TPL-001-4.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Low
Document Name	

Comment

Multiple contingency studies for off-peak conditions which consider maintenance outages for a single element plus the subsequent unplanned loss of an additional single element are included in TPL-001-4. Additional transmission studies including planned maintenance outages would typically overlap with operational studies.

Likes 0	
Dislikes 0	

Response

Jennifer Losacco - 1 - FRCC

Answer	Low
Document Name	

Comment

The risk to the reliable operations of the Bulk Power System (BPS) is low. Planned outages are studied by Operations Personnel, as required by TOP-003, and denied if any reliability risks are identified.

Likes 0	
Dislikes 0	

Response

Jeremy Voll - 1,3,5,6

Answer	Low
Document Name	Cost Effectiveness Pilot Unofficial Comment Form Final Comments_BEPC.docx
Comment	
The likelihood of an occurrence of the probability of a contingency to occur combined with the duration of an outage of less than 6 months is low.	
Likes 0	
Dislikes 0	
Response	
Karen Webb - 1,3,5	
Answer	Low
Document Name	
Comment	
For the majority of utilities, the risk is minimal as these outages are studied in seasonal, next-day, and current day studies for operations performed for existing TOP Standards.	
Likes 0	
Dislikes 0	
Response	
Scott Langston - 1,3,5	
Answer	Low
Document Name	
Comment	
For the majority of utilities the risk is minimal as these outages are studied in seasonal, next-day and current day studies for operations performed for existing TOP Standards.	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Webb Karen
Dislikes 0	
Response	
Robert Tallman - 3,5,6 - SERC, Group Name LG&E and KU Energy	
Answer	Low

Document Name	
Comment	
Operations planning studies are performed prior to approval of the planned outage. If there exists a risk to the BPS, then the planned outage is canceled or postponed until the outage can be taken at a time when there is no risk to the BPS. The operations planning studies covers the timeframe of the planned outage and is done in advance of the planned outage.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Low
Document Name	
Comment	
Xcel Energy feels that the perceived risks discussed here are addressed by the NERC Standard IRO-017-1, whose purpose is "To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon." As such, any perceived deficiencies in addressing the BPS reliability impact of planned maintenance outages of less than six months in duration should be addressed in a modification ot IRO-017-1 and not in TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
John Pearson - 2 - NPCC	
Answer	Low
Document Name	
Comment	
The reliability risk is extremely small based on ISO-NE’s exercise of outage coordination authority and established process of managing reliability and economic impacts.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - 1	

Answer	Low
Document Name	
Comment	
The likelihood of an occurrence of the probability of a contingency to occur combined with the duration of an outage of less than 6 months is low.	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - 1,5	
Answer	Low
Document Name	
Comment	
Operations functions (RCs and TOPs) can provide feedback to long-term planning functions if certain facilities are difficult to get outages on. Existing standards and processes cover this.	
Likes 0	
Dislikes 0	
Response	
David Jendras - 1,3,6	
Answer	Low
Document Name	
Comment	
Given the scope of contingency events already considered in TPL-001-4, it would seem unlikely that critical events would be missed. In addition, such outage events would be reviewed in the Operational Planning horizon for any issues which would occur. Information would be expected to be sparse with respect to planned outages occurring in the Planning time horizon.	
Likes 0	
Dislikes 0	
Response	
Jason Marshall - NA - Not Applicable - NA - Not Applicable	

Answer	Low
Document Name	
Comment	
In New England, NESCOE understands the risks to be low for the reasons explained below and in ISO-NE's comments submitted today. There are two factors that mitigate the reliability risk in New England. First, as discussed above, there is an active and ongoing process in New England, under existing protocols, to coordinate and manage outages. Second, because ISO-NE has procedures in place to account for outages, it is prepared to take operational actions to address needs that may arise.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Low
Document Name	
Comment	
As explained in question 1, Duke Energy believes the likelihood of occurrence of any risk is low based on the ability of Operational Planners to evaluate outages in the operating horizon and mitigate potential risks to the system by modifying the scheduling of outages, re-configuring of the transmission system, and other real-time actions that could be taken to mitigate risk to the BPS.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - 6	
Answer	Low
Document Name	
Comment	
While the probability of an unplanned contingency during a short duration (less than six month) planned outage is much lower than during a longer planned maintenance outage period, these types of scenarios are already evaluated and planned for in the TPL-001-4 planning assessment through the various N-1-1 contingency combinations. It is PacifiCorp's opinion that the short-term planned outage scenarios are better addressed in the operating horizon.	
Likes 0	
Dislikes 0	

Response	
Ginette Lacasse - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Low
Document Name	
Comment	
The risks are minimal because it is rare for outages of less than six months to be known in the planning horizon (more than 1 year out). For those outages that are known, the only risk to BPS reliability is if operations studies do not see the risks that would have been seen by more extensive planning studies, which would be rare.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - 1	
Answer	Low
Document Name	
Comment	
SOL reduction and/or mitigation procedures, if any, would be determined ahead of time as part of the next-day study/operational planning study work in particular if these planned outages are known in advance (< 6 months). Note that these outages can also be addressed as part of the sensitivity work under TPL-001-4 requirement 2.1.4.	
Likes 0	
Dislikes 0	
Response	
David Greene - 10, Group Name SERC PSS	
Answer	Low
Document Name	
Comment	
Planned maintenance outages are considered in operational planning studies which assess the reliable operation of the BPS. Multiple contingency studies for off-peak conditions which consider maintenance outages for a single element plus the subsequent unplanned loss of an additional single element are included in TPL-001-4. These studies support system reliability, system maintenance, and operational flexibility. Moreover, additional transmission studies including planned maintenance outages would typically overlap with operational studies. Therefore, we see a low risk to the	

reliable operation of the BPS if planned maintenance outages of less than six months duration are not considered in TPL-001-4 studies. In addition, information would be expected to be sparse with respect to planned outages occurring in the Planning time horizon.	
Likes 0	
Dislikes 0	
Response	
Yvonne McMackin - 1,4,5	
Answer	Low
Document Name	
Comment	
Since all planned outages have been studied, the occurrence of these risks shall be very low.	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - 1,3,4,5,6 - WECC	
Answer	Low
Document Name	
Comment	
As previously mentioned, we believe transmission planning studies are unnecessary where outage durations are less than 6-months. However, if the Standard Drafting Team develops any requirements for evaluation of short-term planned maintenance outage those requirements should provide options that limit the evaluations to “critical” facilities such as transfer paths. The transmission planner should not be obligated to study every planned maintenance; an approach that would create an administration burden without justifiable reliability benefit.	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - 1,2,3,4,5,6 - MRO	
Answer	Low
Document Name	

Comment
The likelihood of an occurrence of the probability of a contingency to occur combined with the duration of an outage of less than 6 months is low.

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - 1,3,5,6 - MRO	
Answer	Low
Document Name	

Comment
The likelihood is low because the outages are planned and studied in the Operational Horizon. The BES is operated within revised SOLs if required or the planned “multiple” outages are cancelled.

Likes 0	
Dislikes 0	

Response

Daniela Hammons - 1 - Texas RE	
Answer	Low
Document Name	

Comment
CenterPoint Energy does not see risks associated with the current six-month threshold for modeling known outages of generation or Transmission Facility(ies) as specified in TPL-001-4 R1.1.2. Planned maintenance outages of generation or Transmission Facility(ies) with a duration of at least six months are rarely, if ever, scheduled far enough in advance to be included in the Near-Term Transmission Planning Horizon. Shortening the timeframe would only decrease the likelihood of identifying a relevant outage. However, TPL-001-4 R2.1.4 allows for sensitivity analysis to be performed for outages less than six months in duration. If such outages are deemed potentially critical to system reliability, they may be included in the assessment under the current Standard. Furthermore, outages of less than six months reflect operational scenarios and are considered in required operational planning assessments.

Likes 0	
Dislikes 0	

Response

Justin Mosiman - 1,3,5,6 - WECC

Answer	Low
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Low
Document Name	
Comment	
As explained above there are no risks because all planned outages are studied by Operations Planning.	
Likes 0	
Dislikes 0	
Response	
Bob Case - 1,3,5,6 - WECC	
Answer	Low
Document Name	
Comment	
In Black Hills' estimation, there are no risks to reliable operation of the BES, so long as the utility is appropriately completing its operational and outage coordination studies. Note that the study work itself would be fairly minimal. The larger cost would be hours associated with coordination and documentation; satisfying the burden of proof.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - 1 - MRO,RF	
Answer	Medium

Document Name	
Comment	

Response: *The overall likelihood of key planned outages less than 6 month in duration and most planning event contingency combinations in some areas of our system may be medium.*

Please explain your response: *The likelihood of a planned (scheduled or future to-be-scheduled) outages is 100% (high). And the likelihood of an unplanned planning event contingency occurring during planned outage conditions may be low. So, the overall likelihood of the some planned outages and unplanned contingencies combinations is probably medium.*

Likes 0	
Dislikes 0	
Response	
Terry BIlke - 2	
Answer	Medium
Document Name	
Comment	

The BPS may not operate reliably for certain planned maintenance outages if the system is not planned to accommodate such outages, or restrict the RC outage coordination processes in approving certain planned outages, which in turn could result in a safety issue, inadvertent facility damage, or a subsequent forced outage affecting reliability.

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - 10	
Answer	Medium
Document Name	
Comment	

If multiple outages are requested during the same time period and the outages cause potential reliability conflicts, the Reliability Coordinator (RC) has the ability to resolve the scheduling conflicts by rejecting outages.

Likes 0	
Dislikes 0	
Response	

1b. What costs should be considered when evaluating these risks or in adding planned maintenance outages less than six months to TPL-001-4?

Please explain your response:

Bob Case - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

This would likely require an additional engineer for every entity required to comply with the TPL standards.

Likes 0	
Dislikes 0	

Response

Diana McMahon - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

The cost of adding planned maintenance outages less than six months includes the cost of additional study work. If there are multiple planned outages in the same year, multiple scenarios will need to be studied to get an accurate analysis, dramatically increasing the amount of study work. Again, most of this analysis is already performed in the operating horizon, leading to further duplication of work.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

The cost of performing additional studies in the Planning assessment should be considered. As a practical matter, it would be an extremely rare circumstance for there to be a need to build a facility to accommodate a planned outage and the timeline to do so makes it likely impractical.

Likes 0	

Dislikes 0	
Response	
Justin Mosiman - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
The additional costs will likely be for labor. Work would need to be done in analyzing BPA's outage scheduling system and merging the data into the planning assessment studies. As outages are added, removed or moved, studies may need to be re-run for the assessment. A system or additional process would need to be added to track changes to the outage schedule.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - 10	
Answer	
Document Name	
Comment	
Delayed projects and/or maintenance cost may result if outage requests to perform work are rejected. Additionally, planning departments may have to adjust processes to review project/maintenance schedules and incorporate these schedules into the planning cases. Information, already captured in a different processes, may have to be integrated into the planning process.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - 2	
Answer	
Document Name	
Comment	
The additional cost will likely be the human resource time required to include the outages in the planning assessment, which could be	

redundant with the same task (but not a replacement) in outage coordination and operations planning analyses which in general are conducted with more accurate system data thanks to the more predictive conditions at a closer time frame.	
Likes 0	
Dislikes 0	
Response	
Daniela Hammons - 1 - Texas RE	
Answer	
Document Name	
Comment	
Costs to be considered include the additional labor (man hours, number of FTEs, or out-sourcing) to perform the additional assessments. Licensing costs of modeling tools may also increase if additional FTEs are added.	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
The cost would be the burden of studying the planned maintenance outages, which would be a duplication of effort already performed by the Transmission Operator, Balancing Authority or Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - 1,2,3,4,5,6 - MRO	
Answer	
Document Name	
Comment	

Additional costs to consider include duplicative staff, duplicative equipment, additional computing time, and compliance enforcement costs related to performing additional annual planning assessments for TPL-001-4 which are already adequately and properly covered in seasonal, next-day, and current day studies. If daily PRC-005-2 outages must be evaluated, then the number of duplicate annual planning contingency studies with no additional reliability benefit is significant.

Likes 0	
Dislikes 0	

Response

Joe Tarantino - 1,3,4,5,6 - WECC

Answer	
Document Name	

Comment

As previously mentioned, we believe transmission planning studies are unnecessary where outage durations are less than 6-months. However, if the Standard Drafting Team develops any requirements for evaluation of short-term planned maintenance outage those requirements should provide options that limit the evaluations to "critical" facilities such as transfer paths. The transmission planner should not be obligated to study every planned maintenance; an approach that would create an administration burden without justifiable reliability benefit.

Likes 0	
Dislikes 0	

Response

Yvonne McMackin - 1,4,5

Answer	
Document Name	

Comment

Reliability is the most important factor at the District. Impacts on the overall reliability of the BES are not allowed. Cost has not been considered when planned outages are determined.

Likes 0	
Dislikes 0	

Response
Kelly Silver - 1,3,5,6, Group Name Con Edison
Answer	
Document Name	
Comment
N/A. No risks in the Planning horizon. An undue burden. No additional cost should be added.
Likes 0	
Dislikes 0	
Response
David Greene - 10, Group Name SERC PSS
Answer	
Document Name	
Comment
Costs that should be considered include engineering hours to coordinate the inclusion of the planned maintenance outages into the system models, engineering hours to perform the additional studies, and potential capital funding required for corrective action plans to address issues that historically could have been mitigated through operational techniques. As a practical matter, it would be an extremely rare circumstance for there to be a need to build a facility to accommodate a planned outage and the timeline to do so makes it likely impractical.
Likes 0	
Dislikes 0	
Response
Glenn Pressler - 1,3,5
Answer	
Document Name	
Comment
N/A
Likes 0	
Dislikes 0	

Response	
Laura Nelson - 1	
Answer	
Document Name	
Comment	
This should be part of the current TPL-001-4 requirement 2.1.4 scope, in particular if these outages are deemed to be significant by the Transmission Planner. Otherwise they should be dealt with under Operational Planning. If "all" planned maintenance outages less than six months are required to be studied under TPL-001-4, then the additional cost should be commensurate with the number of outages to be studied; each outage would correspond in effect to a new case for which an assessment is being required.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
It is likely that an extra full time employee may be required because of the potential amount of labor and time involved in the preparation and assessment of outage combinations intended for planned maintenance outages with a duration of less than six months.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - 6	
Answer	
Document Name	
Comment	
Additional costs to consider include the substantial increase in the volume of outages to be analyzed and the incremental man-hours necessary to perform the analysis. This may require an increase in highly specialized staff, an increase in support staff, related training costs, additional equipment and facilities, additional computing time, and additional compliance enforcement costs necessary to perform annual planning assessments for TPL-001-	

4.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	

There are costs in engineering time and labor associated with Transmission Planners and Planning Coordinators conducting studies associated with evaluation of known, planned outages less than six months in duration. The expense of the time and labor associated with these studies will be increasingly higher because with each incremental decrease in the duration of outages that must be studied, the frequency of occurrence such planned outages increases – requiring more study time/analysis. The value of the analysis so far out in front of the actual outage schedule date is suspect. For instance, a known planned outage for 2018 may be evaluated in 2016. Changes in outage plans (all outages) and system conditions in the two year interim time between the analysis and the outage are likely to occur, and will have made the analysis meaningless. This can create operational risk because of the error induced by changes in overall outage plans and system conditions may not be recognized as we move from the planning to the operating horizon. There is a risk of complacency in evaluating reliability impacts of outages in the operating horizon because the impacts were thought to have been evaluated under the TPL-001-4 standard.

Likes 0	
Dislikes 0	
Response	
Jason Marshall - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

As a general matter, NESCOE greatly appreciates NERC's initiation of this cost-effectiveness pilot. NESCOE has expressed its strong support in the past for NERC's efforts to incorporate cost-effectiveness analysis into its standard development. It is a priority that the appropriate level of infrastructure is in place to achieve a robust and reliable bulk electric system. Indeed, in New England, consumers have invested heavily in transmission infrastructure for reliability needs. Today, transmission-related costs comprise a greater percentage of a New England consumer's bill than in any other RTO region. NESCOE appreciates these efforts to identify cost-effective approaches to new standards going forward. As NESCOE has stated in past comments, incremental reliability gains cannot be considered in a vacuum, separate from an understanding of the magnitude of risk and cost associated with federal reliability standards. NERC's consideration of costs, reliability risks and benefits should help tailor the most appropriate and cost effective approach to achieving a reliability objective.

In the spirit of a pilot project, NESCOE offers one early broad observation that might increase industry participation in providing input on the expected costs associated with a proposed new or revised standard. To date, NESCOE understands that NERC has relied on industry participants to volunteer cost estimates related to a proposed standard and that, given the resources involved, many entities decline to provide cost details. One approach to

encourage greater participation, and increase understanding of cost impacts, would be for NERC staff or standard development teams ("SDTs") to provide a "straw" or even rough illustrative estimate and seek responses to that information. Entities may be more likely to review and respond to a number or set of numbers than to produce one from scratch. Further, in light of Order 1000's transition to competitive transmission, cost estimates related to transmission infrastructure may be increasingly considered to be competitively sensitive information. Many transmission owners or developers may not want to offer a sense of costs for public review in the NERC standard development process. Of course, this would require NERC or SDTs to expend resources on putting out a straw. However, given the importance of cost-effective analysis, the priority NERC and many other government officials place on the cost-effectiveness program, and emerging competition in transmission development, this may be a prudent and even necessary investment that would save consumers dollars over the longer-term. To be clear, this is a forward-looking suggestion and is not intended to respond to the specific questions posed here on TPL -001- 4.

Regarding the question of cost in connection with TPL-001-4, for the reasons discussed above, imposing a new planning standard in New England for planned outages does not appear to be the most cost-effective approach to address reliability risks associated with planned maintenance outages. ISO-NE already engages in the conservative modeling of reliability needs, with an N-1-1 scenario reflected in the base case. Accordingly, the base case acts as a proxy for units that are unavailable, whether through planned or unplanned events. To remove further facilities for planned maintenance outages, which are already accounted for in existing protocols, would be the equivalent of an N-1-1-1 event. This change would have potentially significant cost implications for New England. The more cost-effective approach in New England is to allow for ISO-NE's existing processes and procedures to plan for, and address, any reliability issues in connection with outages.

Likes 0	
Dislikes 0	

Response

Terry BIlke - 2

Answer	
Document Name	

Comment

Working around a maintenance coordination issue on a system not designed to handle the maintenance can increase the risk to reliability by having to rely on operating guides and workarounds. Increased costs also may occur due to required re-dispatch and/or shifting the maintenance to higher dispatch cost periods. Also, uncertainty of when maintenance can be scheduled and/or denial of scheduled maintenance can increase cost to asset owners that rely on contract personnel.

Likes 0	
Dislikes 0	

Response

David Jendras - 1,3,6

Answer	
Document Name	

Comment

Significant additional labor costs for working shorter-term outage data into contingency lists, and producing additional powerflow cases to analyze these events would be needed. Following contingency simulations, additional time for review of the simulation results would be needed. In rare instances, additional capital costs for corrective action plans might be needed.

Likes 0	
Dislikes 0	

Response

Oliver Burke - 1,5

Answer	
Document Name	

Comment

The capital costs for building out a system that can support outages in the few hours that long-term planning studies cover should be compared to the reductions in O&M in coordinating and scheduling outages.

Likes 0	
Dislikes 0	

Response

larry brusseau - 1

Answer	
Document Name	

Comment

Additional costs to consider include duplicative staff, duplicative equipment, additional computing time, and compliance enforcement costs related to performing additional annual planning assessments for TPL-001-4 which are already adequately and properly covered in seasonal, next-day, and current day studies. If daily PRC-005-2 outages must be evaluated, then the number of duplicate annual planning contingency studies with no additional reliability benefit is significant.

Likes 0	
Dislikes 0	

Response

Hien Ho - 1,3,4,5,6

Answer	
Document Name	

Comment
Costs include maintaining a database, modeling, and studying these planned outages. The details of these planned outages may not be available in Planning Horizon.

Likes 0	
Dislikes 0	

Response

John Pearson - 2 - NPCC	
Answer	
Document Name	

Comment
There is the direct cost of conducting a study of planned maintenance conditions under TPL-001-4 knowing that the study will take into account conditions that may not materialize in the Operation Planning horizon operations staff address in Real-time. That is why outage coordination as administered by ISO-NE for the last 10 years, and what will be required of other System Operators under IRO-017-1, is necessary.

Likes 0	
Dislikes 0	

Response

Robert Tallman - 3,5,6 - SERC, Group Name LG&E and KU Energy	
Answer	
Document Name	

Comment
Since a planned outage can be controlled or canceled, the only cost that exists is the cost of not doing the outage. If the operations planning studies are done enough in advance of the planned maintenance, there is no cost associated with the postponement or cancellation of the outage. If an unplanned outage occurs just before the planned outage causing the planned outage to be postponed or canceled, there would be a cost associated with the cancellation or postponement.

Likes 0	
Dislikes 0	

Response

Lauren Price - 1 - MRO,RF	
Answer	

Document Name	
Comment	
Response: *Certainly, the cost of potential corrective action plans that would reduce or eliminate the risk of a large amount of firm load loss or firm transmission service interruption should be considered.*	
Likes 0	
Dislikes 0	
Response	
Scott Langston - 1,3,5	
Answer	
Document Name	
Comment	
Labor costs	
Likes 0	
Dislikes 0	
Response	
Karen Webb - 1,3,5	
Answer	
Document Name	
Comment	
Labor	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - 1,3,5,6	
Answer	
Document Name	Cost Effectiveness Pilot Unofficial Comment Form Final Comments_BEPC.docx
Comment	

Additional costs to consider include duplicative staff, duplicative equipment, additional computing time, and compliance enforcement costs related to performing additional annual planning assessments for TPL-001-4 which are already adequately and properly covered in seasonal, next-day, and current day studies. If daily PRC-005-2 outages must be evaluated, then the number of duplicate annual planning contingency studies with no additional reliability benefit is significant. Additionally there may be system upgrades identified for these short duration outages that are not necessarily needed long term.

Likes 0	
Dislikes 0	

Response

Jennifer Losacco - 1 - FRCC

Answer	
Document Name	

Comment

Costs can be associated to additional system analysis. Adding planned outages less-than six months into TPL-001-4 will introduce more complexity to the study since a single case can no longer represent an entire season.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	
Document Name	

Comment

Costs that should be considered include engineering hours to coordinate the inclusion of the planned maintenance outages into the system models, engineering hours to perform the additional studies, and potential capital funding required for corrective action plans to address issues that historically could have been mitigated through operational techniques.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - 2, Group Name IRC Standards Review Committee

Answer	

Document Name	
Comment	
Including planned maintenance outages less than six months in duration in studies during one or both seasonal off-peak periods will require entities to devote additional time to the compilation of the Planning Assessment required under TPL-001-4. Also, because planned maintenance outages of all lengths are already accounted for in the operations planning horizon, there is no potential reliability-related cost that follows from not including this as a requirement in TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - 1,3,5,6 - SPP RE	
Answer	
Document Name	
Comment	
Should planned maintenance outages less than six months be added to the TPL-001-4 Standard, the volume of required studies would dramatically increase with little benefit. To complete the increased volume of studies would require hiring additional engineers.	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - 1,3 - NPCC	
Answer	
Document Name	
Comment	
Hydro One Networks Inc. agrees with the IESO (Ontario) in that the additional cost associated will "*likely be that of the human resource time required to include the outages in the planning assessment, which would be redundant with the same task (but not a replacement) in outage coordination and operations planning analyses which in general are conducted with more accurate system data thanks to the more predictive conditions at a closer time frame*".	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
Additional costs to consider include additional staffing, and Man Hours, costs to perform annual planning assessments for TPL-001-4 which are already adequately and properly covered in seasonal, next-day, and current day studies.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
We believe the addition would be duplicative of current short-term operational planning assessments. In order to maintain compliance with this proposal, registered entities would be required to hire additional staff to evaluate and maintain duplicative system models, as well as purchase additional analytical computing and storage resources.	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - 3,4,5,6 - FRCC, Group Name FMPA	
Answer	
Document Name	
Comment	
Engineering time is one cost. If modifications to the standard are structured to create new study cases, which at a minimum would result in one additional case, this will add potentially 15% to 20% to the cost of the existing Assessment and more with every additional case developed. If modifications to the standard are structured such that results are iterative (additional cases made after initial N-1-1 results are studied), Planning Assessments will take more time to complete. Another is the cost, either direct or unintended, of developing, documenting, and auditing an assessment with an administrative focus on achieving compliance with a standard rather than on analyzing and mitigating risks to BPS reliability. The standard drafting team should attempt to quantify these costs based on the specific changes being proposed to the standard.	

Likes 0	
Dislikes 0	
Response	
Bertha Ellen Watkins - 1	
Answer	
Document Name	
Comment	
We believe the addition would be duplicative of current short-term operational planning assessments. In order to maintain compliance with this proposal, registered entities would be required to hire additional staff to evaluate and maintain duplicative system models, as well as purchase additional analytical computing and storage resources.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - 1,3,5,6	
Answer	
Document Name	
Comment	
Additional costs to consider include duplicative staff, duplicative equipment, additional computing time, and compliance enforcement costs related to performing additional annual planning assessments for TPL-001- 4 which are already adequately and properly covered in seasonal, next-day, and current day studies in the operations horizon.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No Dominion, Con-Ed and NextEra	
Answer	
Document Name	
Comment	
There is the direct cost of conducting a study of planned maintenance conditions under TPL-001-4 knowing that the study will take into account conditions that may not materialize in the Operation Planning horizon operations staff address in Real-time. That is why outage coordination as	

administered by ISO-NE for the last 10 years, and what will be required of other System Operators under IRO-017-1, is necessary.	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - 1,3,5,6	
Answer	
Document Name	
Comment	
b. This is not relevant to the Planning Horizion, because these outages should not be considered in planning cases. These outages are considered in the Operations Horizon, and maintenance activities that pose an undue risk to the BES are postponed or other mitigations are developed. Construction/maintenance outages are not allowed to impact the BES.	
Likes 0	
Dislikes 0	
Response	

1c. If you identified one or more risks and identified a likelihood of “medium” or “high”, is there a more cost effective manner to reduce them rather than revising TPL-001-4 or is there an preferred approach to revising TPL-001-4 that takes into consideration cost effectiveness?

Please explain your response including descriptions of potential cost effective solutions and the associated benefits to reliability:

Angela Gaines - 1,3,5,6	
Answer	No
Document Name	
Comment	
No risks were identified for in the Planning Horizon, because these are mitigated in the Operations Horizon, and therefore the planning standard should not be revised.	
Likes 0	
Dislikes 0	
Response	
Bertha Ellen Watkins - 1	
Answer	No
Document Name	
Comment	
We answered “no” based on the low likelihood of these risks occurring.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We answered “no” based on the low likelihood of these risks occurring.	
Likes 0	
Dislikes 0	

Response	
Sandra Shaffer - 6	
Answer	No
Document Name	
Comment	
N/A. Planned outages with durations less than six months should remain in the operating horizon.	
Likes 0	
Dislikes 0	
Response	
David Greene - 10, Group Name SERC PSS	
Answer	No
Document Name	
Comment	
There is no risk and no need to modify TPL-001-4 for this.	
Likes 0	
Dislikes 0	
Response	
Yvonne McMackin - 1,4,5	
Answer	No
Document Name	
Comment	
Reliability is one of the most important factors to the District. Cost has not been considered when planned outages are determined.	
Likes 0	
Dislikes 0	
Response	

Joe Tarantino - 1,3,4,5,6 - WECC	
Answer	No
Document Name	
Comment	
SMUD does not view the risk of not conducting studies on planned maintenance outages as a risk where those outages are less than 6-months.	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - 3,4,5,6 - FRCC, Group Name FMPA	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - 1,3,5,6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
larry brusseau - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Emily Rousseau - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
Regardless of the potential risk level, the cost-effective alternative is to accept the daily system studies which are already completed under TOP-002 Standards and are currently designed to identify potential risk to the BPS.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
A more cost effective method to reduce the risks rather than requiring the study of planned maintenance outages of less than six months in duration under TPL-001-4 would be to revise TPL-001-4 to include coordination between transmission planners and operational planners to review the operational studies or to incorporate only significant planned maintenance outages into TPL-001-4 studies, similar to R3.4.1 and R4.4.1.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - 1 - MRO,RF	

Answer	Yes
Document Name	
Comment	

Response: *Our preference is for the obligation to evaluate planned outages for conditions when they would typically be taken should be part of the requirements for the assessment of "no load loss allowed" planning event contingencies. Otherwise, we suggest that it at least be added to the assessment of extreme event contingencies to evaluate planned outages that are expected to produce more severe System impacts and learn the possible extent of those impacts.*

Likes 0	
Dislikes 0	
Response	

Terry Bllke - 2

Answer	Yes
Document Name	
Comment	

If the TPL-001-4 standard were modified simply by a rule change for processing P6 contingencies during off-peak cases (Load shed would not be allowed as a mitigation measure), simulation of a facility being removed for maintenance and the resulting system satisfying the n-1 reliability criteria could be assessed for any time in the Planning Horizon. So removing the 6 month duration requirement in the current standard (which requires a special simulation and cost to complete) and replacing it with the above modification would be effective and require virtually no additional cost.

Likes 0	
Dislikes 0	
Response	

Colby Bellville - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	
Comment	

Known planned outages less than six months should be evaluated by Operating personnel in the operating horizon. This allows for more accurate prediction/modeling of expected system conditions, actively engages them in analysis and approval of the outage plan, equips them to evaluate changes in their system up to the very day the outage occurs, and further reduces the possibility that unproductive engineering labor would have been expended.

Likes 0	
Dislikes 0	

Response	
Leonard Kula - 2	
Answer	Yes
Document Name	
Comment	
An alternative is to revise the definition of Operational Planning Analysis to change the next day operations part to next day to up to one year.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - 10	
Answer	Yes
Document Name	
Comment	
If the RC requires the TO/GO to provide rolling 12 month (or longer) outage plans, the RC can evaluate the outages, identify issues, and coordinate the outages in order to avoid scheduling conflicts. The 12 month rolling outage plan is a requirement currently in the Interconnection but it is not necessarily applied to the planning horizon.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - 1,3,5,6	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	

Response
Karen Webb - 1,3,5
Answer	
Document Name	
Comment
N/A
Likes 0	
Dislikes 0	
Response
John Pearson - 2 - NPCC
Answer	
Document Name	
Comment
N/A
Likes 0	
Dislikes 0	
Response
Jason Marshall - NA - Not Applicable - NA - Not Applicable
Answer	
Document Name	
Comment
N/A
Likes 0	
Dislikes 0	
Response

Glenn Pressler - 1,3,5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Daniela Hammons - 1 - Texas RE	
Answer	
Document Name	
Comment	
Not Applicable.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
There is no risk and no need to modify TPL-001-4 for this.	
Likes 0	
Dislikes 0	
Response	

2. What, if any, risk to the reliable operation of the BPS, as defined under Section 215 (see question 1 above) is there if an entity does not perform stability analyses for the P0, P1 and P2 categories in TPL-001-4 that consider the possible unavailability of long lead-time equipment?

Please explain your response:

Bob Case - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

Another consideration would be the effort required to complete stability studies for all outages in compliance with the TPL standard, which would seem to set a very high bar.

Black Hills performed a lot of additional work in 2015. The risk associated with long lead time equipment is the P6 (N-1-1) loss of two transformers. That is already studied outside of the long lead time equipment requirement.

Likes 0	
Dislikes 0	

Response

Diana McMahon - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

There is no risk to the reliable operation of the BPS if an entity does not perform stability analyses for the P0, P1 and P2 categories that consider the possible unavailability of long lead-time equipment. The stability analysis for P3 –P7 categories should already include the study of all loss of long lead-time equipment scenarios.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

There is very little risk if stability analysis is not performed for the unavailability of long lead time equipment. If there is an outage of long lead time equipment, system operations will operate around any problem that might be indicated by their analysis. From a stability standpoint this would most likely be a small limitation on the amount of generation at a plant near the outaged element.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - 3,5

Answer	
Document Name	

Comment

AEP considers the risk to be minimal. The system is operated so that single contingencies will not cause SOL or IROL violations. Whether the system operating limitations are of stability or steady-state nature is not relevant and the planning stability analysis does not need to enter into the consideration.

General comments regarding the Cost Effectiveness Pilot itself:

We believe industry needs more than 30 days to provide thoughtful, meaningful feedback regarding cost effectiveness and perceived risk. We recommend that industry be provided 45 days to respond to future Cost Effectiveness comment periods.

Should a NERC project be commissioned as part of this effort, AEP recommends that comments provided during Cost Effectiveness Pilot comment periods be archived at the project's unique web page. This approach should be used for all projects for which Cost Effectiveness comment periods are held, and would be more appropriate than archiving responses on a variety of topics at a single "Cost Effectiveness Pilot web page".

Likes 0	
Dislikes 0	

Response

Justin Mosiman - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

There is low risk to the BPS if BPA does not perform this stability analyses. Studies are already done as part of the BPA spare equipment strategy. BPA does have a stock of spare long lead-time equipment needed to keep a reliable transmission system as well as a stock of parts for repairs. The strategy replenishes this stock as needed.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - 10

Answer	
Document Name	

Comment

If an entity does not perform stability analyses, IROLs may not be identified. Additional impacts including SOL exceedances, voltage stability, dynamic stability, and transfer capability may not be realized without proper study parameters.

In depth stability analysis occurs in the planning horizon. If the unavailability of long-lead time equipment is not considered during planning horizon analysis, potential instability in the operating horizon due to long-lead time equipment outages may not be identified.

Likes 0	
Dislikes 0	

Response

Daniela Hammons - 1 - Texas RE

Answer	
Document Name	

Comment

CenterPoint Energy does not believe there is any risk because the impact of the unavailability of long lead time equipment for TPL-001-4 Category P0, P1 and most P2 conditions is already captured as part of the Category P6 stability analysis.

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - 1,3,5,6 - MRO

Answer	

Document Name	
Comment	
It comes down to determining if multiple outages of long lead-time equipment should be considered. Assuming more than one piece of equipment is out is unreasonable. Contingency P6 already covers overlapping singles.	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - 1,2,3,4,5,6 - MRO	
Answer	
Document Name	
Comment	
Paragraph 89 of Order No. 786 http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/E-2 Transmission Planning Rel. Strd.pdf to consider P0, P1, and P2 stability analyses for long lead-time equipment with outages of more than six months is reasonable if the scope is limited. There are concerns that a P2 stability analysis with an assumed third contingency base case long-term outage can easily go beyond typical electric grid designs resulting in additional transmission construction. Entities already cover the P0 and possible the P1 conditions as part of their normal stability analyses. A P0 no outage condition with an assumed base six-month element outage becomes a P1 outage condition (an N-1 contingency). Similarly a P1 condition with an assumed base six-month element outage becomes a P2 outage condition (an N-2 contingency). However, a P2 condition with an assumed base six-month element outage is an atypical 3rd contingency or N-3 contingency. Unless limited, this could have significant impacts in terms of staff, time, and ultimately electric grid reinforcements. The risks posed by not performing P0, P1, and P2 stability analyses is specific in nature depending upon the type of equipment and the impact of that equipment. Long lead-time equipment could include common Bulk Electric System (BES) equipment with no significant thermal, voltage, and stability impacts. Similarly the equipment could be specialized and be part of a critical BES Facility such as an Interconnected Reliability Operating Limit (IROL). A typical reactor or transformer may take more than 12 months to obtain and have almost no thermal, voltage, or stability impacts if associated with a BES generator that almost never runs. If the equipment isn't typical such as a series capacitor bank used to improve system stability on an IROL, the risks and impact could be high.	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - 1,3,4,5,6 - WECC	
Answer	
Document Name	

Comment
Regarding the spare equipment strategy, the pertinent issue is to evaluate the outage impacts of long lead-time facilities, regardless of limitation, thermal or stability.

Likes 0	
Dislikes 0	

Response

Yvonne McMackin - 1,4,5

Answer	
Document Name	

Comment
The District performs stability analyses for all of the P0, P1 and P2 categories in TPL-001-4 annually. Stability analysis in the annual system assessment indicates that all single outages result in a stable response.

Likes 0	
Dislikes 0	

Response

David Greene - 10, Group Name SERC PSS

Answer	
Document Name	

Comment
There is very little risk if stability analysis is not performed for the unavailability of long lead time equipment. If there is an outage of long lead time equipment, system operations will operate around any problem that might be indicated by their analysis. From a stability standpoint this would most likely be a small limitation on the amount of generation at a plant near the outaged element.

Likes 0	
Dislikes 0	

Response

Glenn Pressler - 1,3,5	
Answer	
Document Name	
Comment	
Minimal risk. ERCOT already requires the study of unavailability of an autotransformer along with a P0, P1 and P7 event. This would only require an additional study of an autotransformer unavailable with a P2 event.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - 1	
Answer	
Document Name	
Comment	
There might be performance issues that remain uncovered unless a stability assessment is performed on time, in particular if such assessment calls for significant de-rates or implementation of a RAS. The operation planning study should include stability evaluation of a system with the maintenance outage of a facility (particularly large one).	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
The risk of not performing P0 and P1 category analysis is minimal because P3 and P6 category analysis covers situations where a piece of equipment is already out of service followed by a second contingency. There is some minimal risk in not performing P2 analysis, but it is partially mitigated by P4 and P5 category analyses that already cover a more severe condition.	
Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - 6	
Answer	
Document Name	
Comment	
Medium risk. Stability analysis is already required for various N-1 and N-1-1 contingencies that include loss of the equipment. The inclusion of stability analysis on contingency combinations with a significantly lower probability of occurrence could potentially identify new exposures.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy agrees that there is some risk to the BPS if P0, P1, or P2 stability analyses are not performed.	
Likes 0	
Dislikes 0	
Response	
Jason Marshall - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
NESCOE may submit comments on this aspect of TPL-001-4 at a later time.	
Likes 0	
Dislikes 0	
Response	
Terry Bllke - 2	

Answer	
Document Name	
Comment	
Initially, the risk is low after an occurrence. The longer any equipment is out of service for unplanned outages, the greater the potential that subsequent contingencies can cause the BPS to operate at higher risk.	
Likes 0	
Dislikes 0	
Response	
David Jendras - 1,3,6	
Answer	
Document Name	
Comment	
The unavailability of long lead-time equipment would not be likely to cause issues with transient stability for which planners aren't already aware.	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - 1,5	
Answer	
Document Name	
Comment	
There are risks to reliability if stability analyses are not performed for single contingency events that assess system performance during a long unplanned outage. For example, a generator step-up transformer or critical autotransformer.	
Likes 0	
Dislikes 0	
Response	

larry brusseau - 1	
Answer	
Document Name	
Comment	

Paragraph 89 of Order No. 786[1] to consider P0, P1, and P2 stability analyses for long lead-time equipment with outages of more than six months is reasonable if the scope is limited. There are concerns that a P2 stability analysis with an assumed third contingency base case long-term outage can easily go beyond typical electric grid designs resulting in additional transmission construction.

Entities already cover the P0 and possible the P1 conditions as part of their normal stability analyses. A P0 no outage condition with an assumed base six-month element outage becomes a P1 outage condition (an N-1 contingency). Similarly a P1 condition with an assumed base six-month element outage becomes a P2 outage condition (an N-2 contingency). However, a P2 condition with an assumed base six-month element outage is an atypical 3rd contingency or N-3 contingency. Unless limited, this could have significant impacts in terms of staff, time, and ultimately electric grid reinforcements.

The risks posed by not performing P0, P1, and P2 stability analyses is specific in nature depending upon the type of equipment and the impact of that equipment. Long lead-time equipment could include common Bulk Electric System (BES) equipment with no significant thermal, voltage, and stability impacts. Similarly the equipment could be specialized and be part of a critical BES Facility such as an Interconnected Reliability Operating Limit (IROL).

A typical reactor or transformer may take more than 12 months to obtain and have almost no thermal, voltage, or stability impacts if associated with a BES generator that almost never runs. If the equipment isn't typical such as a series capacitor bank used to improve system stability on an IROL, the risks and impact could be high.

Likes 0	
Dislikes 0	
Response	

Hien Ho - 1,3,4,5,6	
Answer	
Document Name	
Comment	

Increase loss of firm load.

Likes 0	
Dislikes 0	
Response	

John Pearson - 2 - NPCC	
Answer	
Document Name	
Comment	
Considering the requirements to evaluate P3 through P7, which simulate multiple contingencies, there is little reliability risk addressed through evaluation of P0, P1 and P2 in stability analyses while assuming that a long lead-time piece of equipment is unavailable. In fact, there should be no requirement to look at P0, P1, or P2 when considering the possible unavailability of long lead-time equipment in steady state analyses for the same reason.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	
Document Name	
Comment	
Xcel Energy feels that there is minimal to no risk involved to the BES by not performing stability analyses for P0, P1, P2 categories that consider the possible unavailability of long lead time equipment. We note that TPL-001-4 requires that system must remain stable due to the tripping of more than one facility in these stability analyses. Thus, system stability would be maintained even during the unavailability of spare equipment, thus minimizing if not eliminating the risk to reliable operation of the BPS.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - 1 - MRO,RF	
Answer	
Document Name	
Comment	
Response: *The likelihood that the dynamic system response to P0, P1 and P2 category contingencies would have a significant impact on BES reliability due to the unavailability of long lead-time equipment is low*. **Please explain your response**: *The unavailability of long lead-time equipment can only lead to dynamic BES system angular or voltage instability*	

when the equipment is in a crucial location near an area of weak angular or voltage stability.

Likes 0	
Dislikes 0	

Response

Scott Langston - 1,3,5

Answer	
Document Name	

Comment

There is a risk that a major outage could create a stability issue that is not caught in seasonal operations studies that do not look at stability.

Likes 0	
Dislikes 0	

Response

Karen Webb - 1,3,5

Answer	
Document Name	

Comment

There is a risk that a major outage could create a stability issue that is not caught in seasonal operations studies that do not look at stability.

Likes 0	
Dislikes 0	

Response

Jeremy Voll - 1,3,5,6

Answer	
Document Name	

Comment

Paragraph 89 of Order No. 786 to consider P0, P1, and P2 stability analyses for long lead-time equipment with outages of more than six months is reasonable if the scope is limited. There are concerns that a P2 stability analysis with an assumed third contingency base case long-term outage can easily go beyond typical electric grid designs resulting in additional transmission construction.

Entities already cover the P0 and possible the P1 conditions as part of their normal stability analyses. A P0 no outage condition with an assumed base six-month element outage becomes a P1 outage condition (an N-1 contingency). Similarly a P1 condition with an assumed base six-month element outage becomes a P2 outage condition (an N-2 contingency). However, a P2 condition with an assumed base six-month element outage is an atypical 3rd contingency or N-3 contingency. Unless limited, this could have significant impacts in terms of staff, time, and ultimately electric grid reinforcements.

The risks posed by not performing P0, P1, and P2 stability analyses is specific in nature depending upon the type of equipment and the impact of that equipment. Long lead-time equipment could include common Bulk Electric System (BES) equipment with no significant thermal, voltage, and stability impacts. Similarly the equipment could be specialized and be part of a critical BES Facility such as an Interconnected Reliability Operating Limit (IROL).

A typical reactor or transformer may take more than 12 months to obtain and have almost no thermal, voltage, or stability impacts if associated with a BES generator that almost never runs. If the equipment isn't typical such as a series capacitor bank used to improve system stability on an IROL, the risks and impact could be high.

Likes 0	
Dislikes 0	

Response

Jennifer Losacco - 1 - FRCC

Answer	
Document Name	

Comment

If an entity does not perform a stability analysis for P0, P1, and P2 that considers the unavailability of long lead-time equipment, the risk to the reliable operations of the BPS would be low. Equipment with long lead-times are typically cables and transformers. Excluding autotransformers on the EHV network, long lead-time equipment generally serves local areas; therefore, their unavailability will affect entities' local service area and not the Bulk Power System.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	
Document Name	

Comment

If the unavailability of long lead-time equipment is not considered in stability analysis for P0, P1 and P2 events, there is a risk of detrimental impacts to BPS reliability. Generally, the unavailability of long lead-time equipment studied under P0 will be bounded by the existing P1 studies. The unavailability of long lead-time equipment studied under P1 and P2 may not be considered completely bounded by any existing studies. However, given the scope of contingency events already considered, it would be unlikely that critical events would be missed. Therefore, TVA sees a low risk to the reliable

operation of the BPS if the unavailability of long lead-time equipment is not considered in stability analysis for P0, P1 and P2 events.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - 2, Group Name IRC Standards Review Committee	
Answer	
Document Name	
Comment	
Some risk to the reliable operation of the BPS could exist if an entity were to perform an analysis of only P0, P1, and P2 categories without also considering the additional contingency of the unavailability of long-lead time equipment. However, TPL-001-4 already requires entities to evaluate P3 through P7 categories, which produce the same contingency results that studying P0, P1, and P2 categories would produce assuming unavailability of long-lead time equipment. For this reason, it is unnecessary and inappropriate to require the proposed analysis. * please note IESO does not join the SRC answer to Question #2	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - 1,3,5,6 - SPP RE	
Answer	
Document Name	
Comment	
The risk is minimal to the BPS if an entity does not perform stability analyses for the P0, P1 and P2 categories identified in TPL-001-4. Operational assessments are already performed and cover these conditions and identify potential risk to the BPS.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	

Document Name	
Comment	
The reference to long lead-time equipment, in this context, is vague and could reference any system element impacted by raw material shortages and labor strikes experienced by manufacturers and supply distributors. We therefore assume the question is directed towards specific BES Elements, such as high-voltage substation transformers, which may have long procurement times more than 12 months. The concerns of instability, uncontrolled separation, and cascading failures of these Facilities are likely caused by an exceedance of an Interconnected Reliability Operating Limits, and usually under conditions representative of a P2 category study. Hence, we believe a risk to the reliable operation of the BPS could exist, and that entities should conduct stability analyses regarding these Facilities when they are associated with Interconnected Reliability Operating Limits.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - 1	
Answer	
Document Name	
Comment	
Not performing stability analyses for P0, P1, and P2 events that consider the possible unavailability of long lead-time equipment could lead to not identifying potential system constraints that could lead to system instability, cascading outages, etc.	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - 3,4,5,6 - FRCC, Group Name FMPA	
Answer	
Document Name	
Comment	
FMPA believes there are certain scenarios involving the unavailability of major long lead-time Transmission equipment that could pose a risk to the BPS and warrant special attention to System stability. However, the instance of such events that cause angular of voltage stability impacts beyond those observed by traditional steady state studies is much more infrequent, and adding events to Stability analysis without proper engineering judgment can add extremely significant wasted time. The PC and TP should have the leeway to determine which scenarios should be included in their assessments, based on events that are expected to produce more severe System impacts.	
Likes 0	
Dislikes 0	

Response	
Bertha Ellen Watkins - 1	
Answer	
Document Name	
Comment	
The reference to long lead-time equipment, in this context, is vague and could reference any system element impacted by raw material shortages and labor strikes experienced by manufacturers and supply distributors. We therefore assume the question is directed towards specific BES Elements, such as high-voltage substation transformers, which may have long procurement times more than 12 months. The concerns of instability, uncontrolled separation, and cascading failures of these Facilities are likely caused by an exceedance of an Interconnected Reliability Operating Limits, and usually under conditions representative of a P2 category study. Hence, we believe a risk to the reliable operation of the BPS could exist, and that entities should conduct stability analyses regarding these Facilities when they are associated with Interconnected Reliability Operating Limits.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - 1,3,5,6	
Answer	
Document Name	
Comment	
There is low risk to the BPS if AZPS does not perform this stability analyses. AZPS has a robust spare equipment strategy. Moreover, if an entity does not perform stability analyses for the P0, P1 and P2 categories in TPL-001-4 that consider the possible unavailability of long lead-time equipment there is low risk as these contingencies are likely addressed through stability analysis for categories P3-P7, such as the two overlapping single multiple contingencies studied in P6.	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - 1,3,5,6	
Answer	
Document Name	
Comment	
This would require creating a new stability case for each long lead time piece of equipment, and running a specific set of stability contingencies for each	

of these cases. The workload impact would increase for PGE by more than 20x. We, and most of the industry, do not have the computing power or the data storage capability required to perform this analysis. This is not just running stability for P0, P1, and P2 contingencies; this is essentially running stability for P6 contingencies.	
Likes 0	
Dislikes 0	
Response	

2a. If there are risks to the reliable operation of the BPS, are the likelihood of the occurrence of these risks low, medium or high? **Please explain your response:**	
Jeremy Voll - 1,3,5,6	
Answer	
Document Name	
Comment	
See the answer for item 2 above.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - 1	
Answer	
Document Name	
Comment	
See the answer for item 2 above	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - 1,2,3,4,5,6 - MRO	
Answer	
Document Name	
Comment	
See the answer for item 2 above.	
Likes 0	
Dislikes 0	
Response	

Daniela Hammons - 1 - Texas RE	
Answer	
Document Name	
Comment	
Not Applicable.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - 2	
Answer	
Document Name	
Comment	
The IESO believes that responsible entities need to ensure acceptable steady state and stability performance of the BPS for the events that the system is designed and operated to withstand, which include the P0, P1 and P2 categories in TPL-001-4, when assessing the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment. Reliable operation may be at risk if stability analyses for these events are not performed for the protracted conditions where the spare equipment is unavailable.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - 10	
Answer	
Document Name	
Comment	
The likelihood of the risks described in #2 is Low to High. The issue is each case may present a different level of risk to the BPS. Without studying it, the risk is unknown until the operations horizon.	
Likes 0	
Dislikes 0	
Response	

Diana McMahon - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
No risks were identified. The stability analysis for P3 –P7 categories should already include the study of all loss of long lead-time equipment scenarios.	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - 1,3,5,6	
Answer	Low
Document Name	
Comment	
There is a chance that if a long lead time piece of equipment is out of service, that there is a stability risk to the system that is unknown, because we don't do P6 stability studies.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - 1,3,5,6	
Answer	Low
Document Name	
Comment	
See response to question 2.	
Likes 0	
Dislikes 0	

Response	
Chris Gowder - 3,4,5,6 - FRCC, Group Name FMPA	
Answer	Low
Document Name	
Comment	
The unavailability of long lead-time equipment with the potential to cause impacts to the BPS are low probability, infrequent events.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - 1	
Answer	Low
Document Name	
Comment	
The risks would be comenserate with the number of non-spare long lead time items that are out of service. In GTCs case, this is low because we maintain a shared spare components database.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - 1,3,5,6 - SPP RE	
Answer	Low
Document Name	
Comment	
Operational assessments are already performed and designed to cover these conditions and identify potential risk to the BPS.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - 2, Group Name IRC Standards Review Committee	
Answer	Low
Document Name	
Comment	
Planning analyses already effectively consider the effect of an outage of equipment with a long lead-time for replacement plus a P0, P1, or P2 category event as part of required analyses of P3 through P7 categories. Thus there is no incremental risk to the reliable operation of the BPS in the absence of a requirement to conduct the proposed analysis.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Low
Document Name	
Comment	
Given the scope of contingency events already considered, it would be unlikely that critical events would be missed. Events which would tend to produce the more severe impacts on system stability are already given considerable attention.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - 1 - MRO,RF	
Answer	Low
Document Name	
Comment	
Response: *The overall likelihood that the unavailability of long lead-time equipment would have significant impact on BES reliability due to dynamic system response to P0, P1 and P2 category contingencies may be low.* **Please explain your response**: *The likelihood that the unavailability of long lead-time equipment would have a stability impact is low and the likelihood that a stability impact BES reliability due to P0, P1 and P2 category contingencies would be significant is also low.*	
Likes 0	
Dislikes 0	

Response	
Robert Tallman - 3,5,6 - SERC, Group Name LG&E and KU Energy	
Answer	Low
Document Name	
Comment	
Since the stability studies are performed for P4 through P7 events, outage of long lead equipment is considered and stability studies are performed (P6), where the prior outage of a long lead item is included in the P6 evaluation. If there is a risk to the BPS, corrective action plans are identified as required by the existing TPL-001-4 standard.	
Likes 0	
Dislikes 0	

Response	
Amy Casuscelli - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Low
Document Name	
Comment	
The stability risk due to the unavailability of long lead time equipment for P0, P1, P2 categories is inherently addressed by the stability analysis performed for the remaining categories P3-P7 which consists of the stability analysis of multiple contingencies.	
Likes 0	
Dislikes 0	

Response	
John Pearson - 2 - NPCC	
Answer	Low
Document Name	
Comment	
There is very limited risk. The likelihood of the occurrence of such limited risk is extremely small.	
Likes 0	
Dislikes 0	

Response	
Hien Ho - 1,3,4,5,6	
Answer	Low
Document Name	
Comment	
Most of these contingencies are studies under P6 (Two overlapping singles) except for the combinations of a transmission element and a bus section or a breaker fault. The risk of these failures is low. In the event such failure occurs, seasonal and daily studies should identify and mitigate any stability issues. In addition to spare equipment, there are a number of other mitigation strategies that can be deployed in less than 12 months such as relay changes, RAS installation, or generation redispatch. Modeling these types of mitigation for stability analysis takes significantly more time than the modeling required for steady state analysis.	
Likes 0	
Dislikes 0	

Response	
David Jendras - 1,3,6	
Answer	Low
Document Name	
Comment	
As above, given the scope of contingency events already considered in TPL-001-4, it would seem unlikely that critical events would be missed. Contingency events which would tend to have the more severe impacts on transient stability issues, typically related to generation outlet facilities, are already given significant attention in analysis work related to TPL-001-4.	
Likes 0	
Dislikes 0	

Response	
Colby Bellville - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Low
Document Name	
Comment	
The likelihood of occurrence of Low is predicated on the belief that there are not a lot of IROLs on the system, however, an entity will most likely not know the answer to this until the actual study has been performed.	

Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Low
Document Name	
Comment	
As mentioned above, the fact that N-1-1 conditions and more severe contingencies are covered in categories P3 through P6 means that the risk of not performing P0-P2 stability analyses considering unavailability of long lead time equipment is minimal.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - 1	
Answer	Low
Document Name	
Comment	
This is hard to quantify as each case could represent a different level of risk. Performing a study that includes both steady-state and dynamic of the system will identify possible risks which can be ranked after this analysis.	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - 1,3,5	
Answer	Low
Document Name	
Comment	
TPL-001-4 does not provide clear performance metrics during the unavailability of long-lead time equipment, therefore the impact is minimal. Because it is unclear, we believe it is left up to the TSP to determine risk of the event and whether it should be mitigated.	

Likes 0	
Dislikes 0	
Response	
David Greene - 10, Group Name SERC PSS	
Answer	Low
Document Name	
Comment	
As above, given the scope of contingency events already considered in TPL-001-4, it would seem unlikely that critical events would be missed. Contingency events which would tend to have the more severe impacts on transient stability issues, typically related to generation outlet facilities, are already given significant attention in analysis work related to TPL-001-4. Also as explained in Section 2 above.	
Likes 0	
Dislikes 0	
Response	
Yvonne McMackin - 1,4,5	
Answer	Low
Document Name	
Comment	
The District performs stability analyses for all of the P0, P1 and P2 categories in TPL-001-4 annually. Stability analysis in the annual system assessment indicates that all single outages result in a stable response.	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - 1,3,5,6 - MRO	
Answer	Low
Document Name	
Comment	

None. Long lead-time equipment tends to be transformers. If a BES transformer is out of service, the next worst outage is typically loss of another parallel transformer. This contingency is already considered as a P6 event. Moving the transformer outage to P0, P1 and P2, for example, is burdensome on the planner and doesn't improve reliability.

Likes 0	
Dislikes 0	

Response

Justin Mosiman - 1,3,5,6 - WECC

Answer	Low
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Marsha Morgan - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Low
Document Name	

Comment

Explained above.

Likes 0	
Dislikes 0	

Response

Bob Case - 1,3,5,6 - WECC

Answer	Low
Document Name	

Comment

Again, recommend separating the operational horizon from the planning horizon.

Likes 0	
Dislikes 0	
Response	
Bertha Ellen Watkins - 1	
Answer	High
Document Name	
Comment	
Although preventive measures, such as shared transformer inventories, have been implemented to address the availability concern of high-voltage substation transformers, these measure may not account for every possible catastrophe.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	High
Document Name	
Comment	
Although preventive measures, such as shared transformer inventories, have been implemented to address the availability concern of high-voltage substation transformers, these measure may not account for every possible catastrophe.	
Likes 0	
Dislikes 0	
Response	
Karen Webb - 1,3,5	
Answer	Medium
Document Name	
Comment	
Medium, because the issue is important, but would most likely be looked at for stability by most utilities if thermal or Low voltage issues in outage studies showed reason for concern.	

Likes 0	
Dislikes 0	
Response	
Scott Langston - 1,3,5	
Answer	Medium
Document Name	
Comment	
Medium, because the issue is important, but would most likely be looked at for stability by most utilities if thermal or Low voltage issues in outage studies showed reason for concern.	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - 1,5	
Answer	Medium
Document Name	
Comment	
Contingency events studied that include multiple facilities out simultaneously should address high risk events.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - 2	
Answer	Medium
Document Name	
Comment	
Planning analyses already consider the effect of an outage of equipment with a long lead-time for replacement plus a P0, P1, or P2 category event as part of required analyses of P3- P7 categories. Thus there is no incremental risk to the reliable operation of the BPS in the absence of a requirement to	

conduct the proposed analysis.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - 6	
Answer	Medium
Document Name	
Comment	
Low to Medium risk of occurrence, depending on the equipment being evaluated. Stability analysis of equipment with a higher probability of complete failure (transformers, circuit breakers) in the absence of spare inventory, may identify practical system risks. However, stability analysis on equipment with significantly lower probabilities of complete failure (series and shunt capacitors, series and shunt reactors, dynamic reactive support), for which maintaining a spare inventory is impractical, may unnecessarily identify deficiencies that have an exceptionally low risk of occurrence.	
Likes 0	
Dislikes 0	
Response	

2b. What costs should be considered when evaluating these risks?

Please explain your response:

Bob Case - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

Additional engineering resource would be required.

Likes 0	
Dislikes 0	

Response

Diana McMahon - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

The cost of duplicative study work.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

The cost of performing the additional stability analysis.

Likes 0	
Dislikes 0	

Response

Justin Mosiman - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Costs can range from the need for additional studies or a corrective action plan (low costs) to the need to purchase additional spare equipment (signification costs).	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - 10	
Answer	
Document Name	
Comment	
Planning departments may have to adjust processes to perform stability studies that require consideration of long lead-time equipment.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - 2	
Answer	
Document Name	
Comment	
The cost associated with the risks could range from local instability or unsupplied energy to potential cascading to the interconnected system, depending on the area for which stability analyses are not performed.	
Likes 0	
Dislikes 0	
Response	

Daniela Hammons - 1 - Texas RE	
Answer	
Document Name	
Comment	
Costs to be considered include the additional labor (man hours, number of FTEs, out-sourcing) to perform the additional assessments. Licensing costs of modeling tools may also increase if additional FTEs are added.	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
The study cost burden should be considered. The entity's spare equipment strategy should have considered the costs, benefits and risks. R2.1.5 is unclear whether the System adjustments identified in P6 are transferable to P0, P1 and P2. Additional System adjustments may be required, such as curtailment of Firm transmission service for the duration of the outage. Note 9 or R2.1.5 could use some clarity. The provision of transformer spares to improve the availability of Firm transmission service should be an economic choice for the Firm transmission service customer rather than a mandatory reliability requirement.	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - 1,2,3,4,5,6 - MRO	
Answer	
Document Name	
Comment	
See the answer for item 2 above.	
Likes 0	
Dislikes 0	
Response	

Yvonne McMackin - 1,4,5	
Answer	
Document Name	
Comment	
Reliability is one of the most important factors to the District. Impacts on the overall reliability of the BES are not allowed. Cost has not been considered when planned outages are determined.	
Likes 0	
Dislikes 0	
Response	
David Greene - 10, Group Name SERC PSS	
Answer	
Document Name	
Comment	
If such analyses were to be considered, additional labor costs would be associated with producing dynamic models and performing additional transient stability simulations, and the associated need to review the simulation results. Additional costs that should be considered include potential capital funding required for corrective action plans as a result of the new requirement.	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - 1,3,5	
Answer	
Document Name	
Comment	
The cost of performing an additional study of an autotransformer unavailable along with a P2 is minimal for our system.	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - 1	
Answer	
Document Name	
Comment	

Both costs associated w/ the additional study work being called for under the conditions described in 2 above and costs related to the impact on the system resulting from the exposure to the non-studied stability performance.

This latter one is hard to determine without performing the actual studies.

Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	

As mentioned above, the fact that N-1-1 conditions and more severe contingencies are covered in categories P3 through P6 means that the risk of not performing P0-P2 stability analyses considering unavailability of long lead time equipment is minimal.

Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - 6	
Answer	
Document Name	
Comment	

Administrative costs including transmission planning staff. There is a limited supply of trained professionals in North America capable of performing these stability studies. Locating and training additional transmission planners carries a high cost burden. Spare inventory for reactive devices with a low probability of failure would create a significant cost burden on utility ratepayers nationwide. Many of these reactive support devices are custom designed and a complete spare would have a high cost for a minimal system reliability benefit.

Likes 0	

Dislikes 0	
Response	
Terry BIlke - 2	
Answer	
Document Name	
Comment	
Adding a requirement to TPL-001-4 for entities to perform a stability analysis for P0, P1, and P2 categories that considers the possible unavailability of long-lead time equipment would require PCs to devote additional resources to the expanded study requirements. Further as explained above, planning studies already consider the effects of such losses.	
Likes 0	
Dislikes 0	
Response	
David Jendras - 1,3,6	
Answer	
Document Name	
Comment	
If such analyses were to be considered, additional labor costs would be associated with producing dynamic models and performing additional transient stability simulations, and the associated need to review the simulation results.	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - 1,5	
Answer	
Document Name	
Comment	
The cost to keep on hand spare equipment that reduces the lead time to just installation time.	

Likes 0	
Dislikes 0	
Response	
larry brusseau - 1	
Answer	
Document Name	
Comment	
Additional costs would include time and staff required to perform more stability studies.	
Likes 0	
Dislikes 0	
Response	
Hien Ho - 1,3,4,5,6	
Answer	
Document Name	
Comment	
Costs include study cost and maintaining a spare equipment strategy.	
Likes 0	
Dislikes 0	
Response	
Robert Tallman - 3,5,6 - SERC, Group Name LG&E and KU Energy	
Answer	
Document Name	
Comment	
When evaluating the P6 event where the prior outage is a long lead item, a corrective action plan must be identified. No cost should be considered since the corrective action plan will mitigate the risk.	
Likes 0	
Dislikes 0	

Response
Lauren Price - 1 - MRO,RF
Answer
Document Name
Comment
Response: *Certainly, the cost of potential corrective action plans that would resolve the performance deficiencies should be considered. In additional, the potential cost of performing stability analysis on long lead-time equipment that are likely to be unnecessary should be considered.*
Likes 0
Dislikes 0
Response
Scott Langston - 1,3,5
Answer
Document Name
Comment
Labor costs
Likes 0
Dislikes 0
Response
Karen Webb - 1,3,5
Answer
Document Name
Comment
Labor
Likes 0
Dislikes 0
Response

Jeremy Voll - 1,3,5,6	
Answer	
Document Name	
Comment	
Additional costs would include time and staff required to perform more stability studies.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	
Document Name	
Comment	
Costs that should be considered include engineering hours to perform the additional studies as well as potential capital funding required for corrective action plans as a result of the new requirement.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - 2, Group Name IRC Standards Review Committee	
Answer	
Document Name	
Comment	
Adding a requirement to TPL-001-4 for entities to perform a stability analysis for P0, P1, and P2 categories that considers the possible unavailability of long-lead time equipment would require PCs to devote additional resources to the expanded study requirements. While costs of reliability impacts should generally be considered in evaluating standards, in this case, there is no reliability impact (or associated cost) because planning studies already consider the effects of such losses.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - 1,3,5,6 - SPP RE	
Answer	
Document Name	
Comment	
Should stability analyses for the P0, P1 and P2 categories that consider the possible unavailability of long lead-time equipment be added to the TPL-001-4 Standard, the volume of required studies would dramatically increase with little benefit. To complete the increased volume of studies would require hiring additional engineers.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
We believe registered entities will incur additional costs to include BES Facilities with long procurement times in their stability analyses. These costs will include additional staff to identify and maintain applicable facilities, but opportunity costs associated with shifting existing staff away from other reliability studies.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - 1	
Answer	
Document Name	
Comment	
Costs for maintaining spare equipment and/or implementing projects to mitigate identified problems via the stability analysis. If you already have a spare equipment pool for steady state issues, there should be no additional costs.	
Likes 0	
Dislikes 0	

Response
Chris Gowder - 3,4,5,6 - FRCC, Group Name FMPA
Answer	
Document Name	
Comment
Engineering time is one cost. If PC and TP staff are not afforded appropriate leeway to select events that truly have a stability impact, the risk is a substantial amount of time spent creating cases, running simulations, and analyzing the results (plots, text files, etc). Another is the cost of implementing Corrective Action Plans for low probability, infrequent events. The standard drafting team should attempt to quantify these costs based on the specific changes being proposed to the standard.
Likes 0	
Dislikes 0	
Response
Bertha Ellen Watkins - 1
Answer	
Document Name	
Comment
We believe registered entities will incur additional costs to include BES Facilities with long procurement times in their stability analyses. These costs will include additional staff to identify and maintain applicable facilities, but opportunity costs associated with shifting existing staff away from other reliability studies.
Likes 0	
Dislikes 0	
Response
Michelle Amarantos - 1,3,5,6
Answer	
Document Name	
Comment
This suggests not having a spare equipment strategy and planning to run the system in a post N-1 condition for an extended period for an unknown outage. This could be interpreted as creating a scenario where one would have to plan the system as a N-1-1 without system adjustments. This would tax the computational power of even the most sophisticated entities leading to increased staff, redundant transmission equipment additional

computational equipment, and additional computing time.	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - 1,3,5,6	
Answer	
Document Name	
Comment	
PGE - We don't understood this question.	
Likes 0	
Dislikes 0	
Response	

2c. If you identified one or more risks and identified a likelihood of “medium” or “high” is there a cost effective manner to reduce them rather than revising TPL-001-4 or is there an preferred approach to revising TPL-001-4 that takes into consideration cost effectiveness?

Please explain your response including descriptions of potential cost effective solutions and the associated benefits to reliability:

Angela Gaines - 1,3,5,6	
Answer	No
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
Revision of TPL-001-4 would be required if Section 215 is applied to stability analyses.	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - 1,3,5,6	
Answer	No
Document Name	
Comment	
Revising the TPL-001-4 standard to evaluate P2 stability impacts of long lead-time equipment associated with identified IROLs seems reasonable.	
Likes 0	
Dislikes 0	

Response	
Colby Bellville - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Although the risk is relatively low the reliability impact could be significant. The cost of analysis does not appear to be very high. The benefit to reliability would be the understanding of locations where lack of spare equipment may have a significant reliability impact. Duke Energy believes the suggested studies should be performed.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
Not applicable	
Likes 0	
Dislikes 0	
Response	
Yvonne McMackin - 1,4,5	
Answer	No
Document Name	
Comment	
Reliability is one of the most important factors to the District. Impacts on the overall reliability of the BES are not allowed. Cost has not been considered when planned outages are determined.	
Likes 0	

Dislikes 0	
Response	
Chris Gowder - 3,4,5,6 - FRCC, Group Name FMPA	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - 1,5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bertha Ellen Watkins - 1	
Answer	Yes
Document Name	
Comment	
The concerns of instability, uncontrolled separation, and cascading failures of these Facilities are likely caused by an exceedance of an Interconnected Reliability Operating Limits, and usually under conditions representative of a P2 category study. We feel studies under these parameters are reasonable.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	

The concerns of instability, uncontrolled separation, and cascading failures of these Facilities are likely caused by an exceedance of an Interconnected Reliability Operating Limits, and usually under conditions representative of a P2 category study. We feel studies under these parameters are reasonable.

Likes 0	
Dislikes 0	

Response

Karen Webb - 1,3,5

Answer	Yes
Document Name	

Comment

Use existing operations outage studies performed for TOP standards to point to the need or create a mechanism for which the outages would be studied for stability on an “as needed” basis.

Likes 0	
Dislikes 0	

Response

Scott Langston - 1,3,5

Answer	Yes
Document Name	

Comment

Utilize existing operations outage studies performed for TOP standards to point to the need or create a mechanism for which the outages would be studied for stability on an “as needed” basis.

Likes 0	
Dislikes 0	

Response

larry brusseau - 1

Answer	Yes
Document Name	

Comment

Revising the TPL-001-4 standard to evaluate P2 stability impacts of long lead-time equipment associated with identified IROLs seems reasonable.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - 6	
Answer	Yes
Document Name	
Comment	
Use of historical outage probabilities in development of the standard to remove the requirement for evaluating the unavailability of long-lead equipment for lower probability failures, including series and shunt capacitors, series and shunt reactors and dynamic reactive support devices.	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - 1,2,3,4,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Revising the TPL-001-4 standard to evaluate P2 stability impacts of long lead-time equipment associated with identified IROLs seems reasonable. The NSRF thinks our key comment on cost-effectiveness and risk is where the most effective solution to accommodate maintenance of a particular facility is construction. If you wait to capture the issue in the operating horizon, you either increase the risk and have to rely on operating guides, re-dispatch, and workarounds; or you shift the work to some other period where dispatch cost is higher.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - 2	
Answer	Yes
Document Name	

Comment
A cost effective manner to address the potential risk could be to include stability analyses for the P0, P1 and P2 events when evaluating the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - 1,3,5,6

Answer	
Document Name	

Comment
N/A

Likes 0	
Dislikes 0	

Response

Glenn Pressler - 1,3,5

Answer	
Document Name	

Comment
N/A

Likes 0	
Dislikes 0	

Response

David Greene - 10, Group Name SERC PSS

Answer	
Document Name	

Comment

There is very little risk and no need to modify TPL-001-4 for this.

The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.

Likes 0	
Dislikes 0	

Response

Daniela Hammons - 1 - Texas RE

Answer	
Document Name	

Comment

Not Applicable.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - 10

Answer	
Document Name	

Comment

A change in process would be required and needs to be supported in some manner in order to be effective. The amount of change would dictate cost. The real cost of not doing less than six months would require an in-depth look at the monetary impacts of delayed projects and changes in generation patterns to accommodate operation horizon events caused by outages not studied. History tends to indicate that costs are cheaper when planned (proactively) early than when reactive measures are taken to solve issues.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
There is very little risk and no need to modify TPL-001-4 for this.	
Likes 0	
Dislikes 0	
Response	

Proposed NPCC Regional Transition SPS to Remedial Action Schemes (RAS)

Background Process and Discussion

TFCP

August 2nd & 3rd, 2016

RAS Transition

- Overview
  - Continent –wide need to establish a uniform definition of RAS/SPS.
  - RAS Definition FERC Approved 11/19/2015 (Order 818).
  - FERC Letter Order 6/23/2016 Approving Revised Definition of SPS.(New SPS Definition="See Remedial Action Scheme.")
  - PRC-012-2 *Remedial Action Schemes* NERC BOT Approved 5/5/2016.
    - NPCC working with NERC on FERC filing and addressing concerns.
  - NERC Rules of Procedure
    - Regional Criteria 'not inconsistent' with ERO Standards
    - Criteria should augment and be more stringent/specific.
  - TFCP Provides Coordination and Oversight of the Existing NPCC SPS Regional Approval Process (NPCC Directory#7 –Appendix B)
    - Maintain? RC Procedures?

Proposed NPCC Transition Process

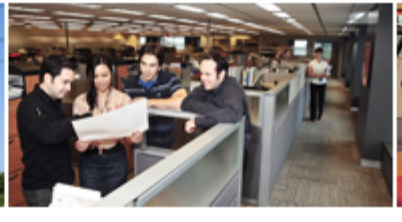
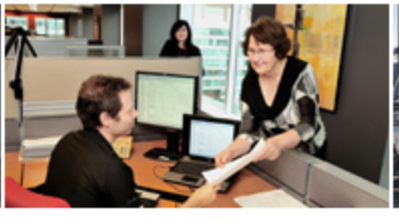
- Phase#1:
  - TFSS Establishes NPCC RAS List based on new definition using SPS list as a starting point:
    - NPCC Protection Systems that Conform to the Revised Definition of RAS.
    - Certain Existing SPS's do not Conform to the Revised Definition.
    - Certain Newly defined RAS's have not undergone a Regional Review.
    - RAS (Type I and II) Limited Impact RAS (Type III): Maintain 3 categories.
- Phase#2:
  - TFSP Considers Retirement of NPCC Glossary Term 'SPS'
    - Review all NPCC Documents (Directories, Criteria, Guidelines and Procedures)
    - Replace SPS with RAS.
- Phase#3:
  - TFSP Reviews Directory#7 (Pending Approval of PRC-012-2)
    - Criteria Review
    - Limited Impact vs. Existing Typing (Pending Final FERC Order on PRC-012-2)

NERC PRC-025-1

A relay loadability criterion using power flow equations

An application for remote generation facilities

TFSP
Juillet 2016



Eric Loiselle, ing.
2016-07-13

Orientation des Automatismes,
Automatismes de transport,
Direction Expertise

Hydro Québec TransÉnergie

Background PRC-025-1

PURPOSE

To prevent unnecessary tripping of generators by its protective relay in case of a grid voltage collapse.

REQUIREMENT

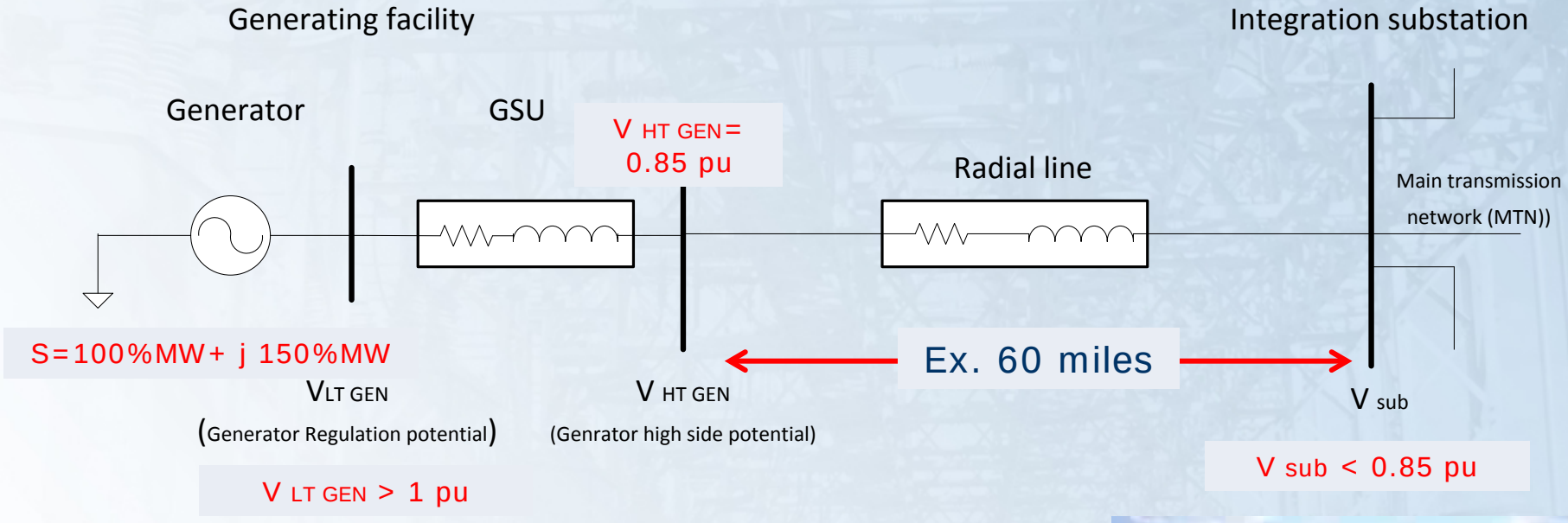
R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.

KEY ASSUMPTION FOR PRC-025 (AND PRC-023)

The protective relay must not operate for voltages above 0.85 pu.

NERC SPCS, July 2010, “Power Plant and Transmission System Protection”
“…0.85 per unit voltage at the system high side of the generator step-up transformer is used as the stressed system voltage condition for an extreme but recoverable system event. This transmission system voltage was observed on August 14, 2003 prior to acceleration of the cascading outages.”

What about remote generating facilities?



- Assumptions for PRC-025 (for example, option 14a)
  - Fixed Power Output, P = 100% and Q = 150%
  - 0.85 pu voltage level at high side of the generating facility
  - A recoverable stressed voltage level at the main transmission network
- These assumptions are not <u>simultaneously</u> realistic for a remote generation facility connected with a long radial line.



Loadability criterion based on power flow
How to calculate?

Key points

- Maximum stressed voltage condition at the remote end of the line (Generation integration substation) V_{sub} = 0.85 PU
- Pmax generator = 1 PU
- Fixed system impedances : GSU + line
- Maximum regulation potential $V_{LV\ GEN}$ = 1.05 PU
- Qmax and $V_{HT\ GEN}$ calculated with load flow equations

1 P U

1.05 P U

0.85 PU

Imposed as the reference

System of 2 unknowns and 2 equations

$$P_{alt_MAX} = \frac{|V_{LV_GEN}|^2}{|Z_{xfo+line}|}\cos(\theta_{xfo+line}) - \frac{|V_{LV_GEN}||V_{sub}|\cos(\theta_{LV_GEN} - \theta_{Sub} + \theta_{xfo+line})}{|Z_{xfo+line}|}$$

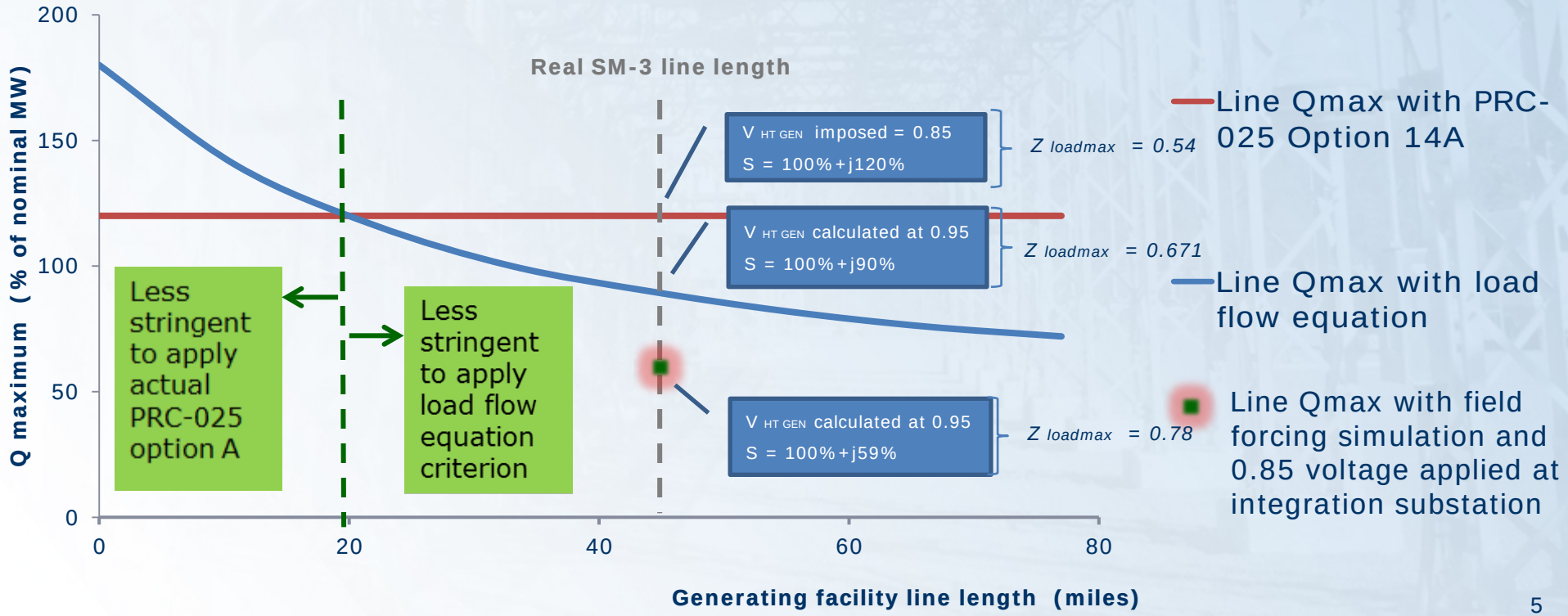
$$Q_{alt_MAX} = \frac{|V_{LV_GEN}|^2}{|Z_{xfo+line}|}\sin(\theta_{xfo+line}) - \frac{|V_{sub}||V_{LV_GEN}|\sin(\theta_{LV_GEN} - \theta_{SUB} + \theta_{xfo-line})}{|Z_{xfo+line}|}$$

Loadability criterion based on power flow

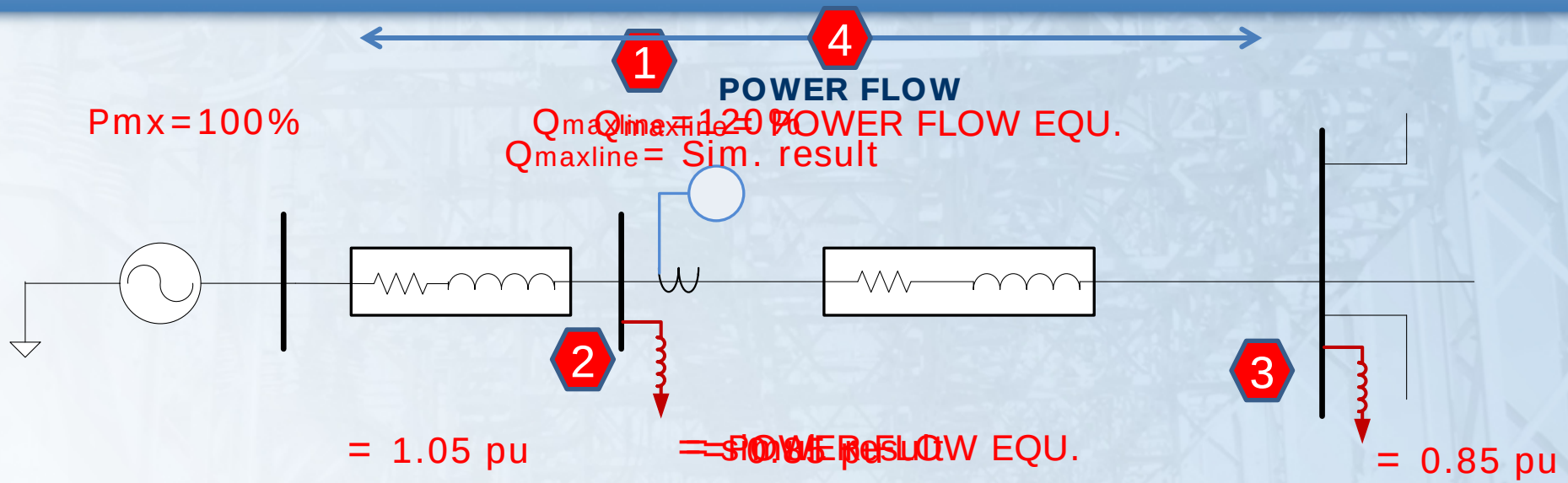
Avantages

- Applies to all generator types, connection topologies (generator output not needed)
- No need for simulation, only GSU and line impedance needed
- Consistent with the reliability objective of the standard

Qmax vs line length, example for SM-3 hydro generating facility



SIMULATION VALIDATIONS



Generating facility	QmaxLine (% Gen_Pnominal)			
	0.85pu local end		0.85pu remote end	
	1 PRC-025 Option 14a	2 Simulation PSS®E	3 Simulation PSS®E	4 Power flow
MANIC 5	120%	64%	38%	41%
MANIC 5 PA	120%	73%	46%	47%
SM-3	120%	80%	59%	70%
LG1	120%	84%	52%	70%

A PRC-025 criterion based on load flow (proposed addition for option 14)

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 (21) – directional toward the Transmission system – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 7	14a	0.85 per unit of the line nominal voltage	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
		OR		
		14c	Calculated HV line voltage determined by load flow equations when the remote end of the generating fallibility is at a stressed voltage of 0.85, with a low voltage of the generator at 1.05 pu.	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 Mvar calculated as determined by load flow equations when the remote end of the generating facility is at a stressed voltage of 0.85 and the low voltage of the generator is at 1.05 pu.

This addition could be naturally extended to the other options

Impact

- Hydro-Québec has approx. 10 remote generation facilities that can be considered « remote » to the main electric network
  - Applying actual PRC-025 criteria is costly, since it requires performing protection studies and relay setting changes
  - Applying actual PRC-025 criteria would render actual backup protection schemes less effective, since zone 3/4 coverage would have to be constrained

No reliability benefit

- A new loadability criteria based on load flow would benefit remote generation facilities while respecting the industry established maximum recoverable voltage collapse event (0.85 pu)

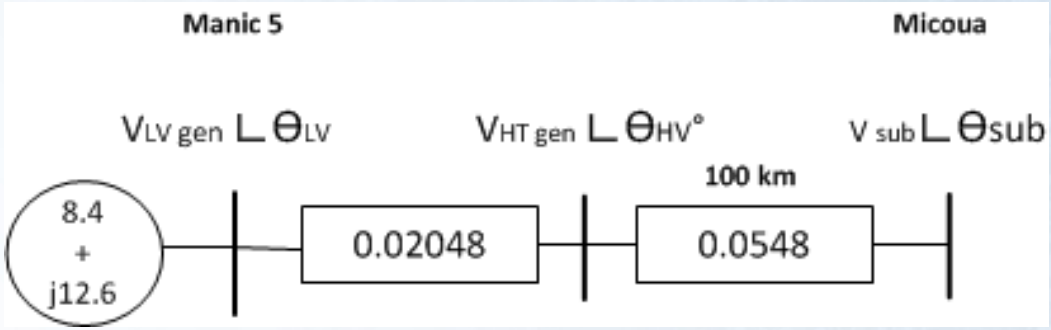

Hydro
Québec

Example: Manic 5 generating facility assessment with actual PRC-025-1 criteria

PRC-025 Criteria

-> S =100%P+j150%P

-> $V_{HT\ GEN}$= 0.85 pu





S =100%P+j150%P $V_{HT\ GEN}$= 0.85 pu

Solving Load flow equations

$V_{LT\ GEN}$ = 1.08 pu

V_{sub} = 0.57 pu

To meet 0.85 pu voltage HV bus and Qmax = 150% at Manic 5, load flow equations impose 0.57 pu voltage at Micoua

-> 0.57 pu at the main transmission network is a not a recoverable stressed voltage level.

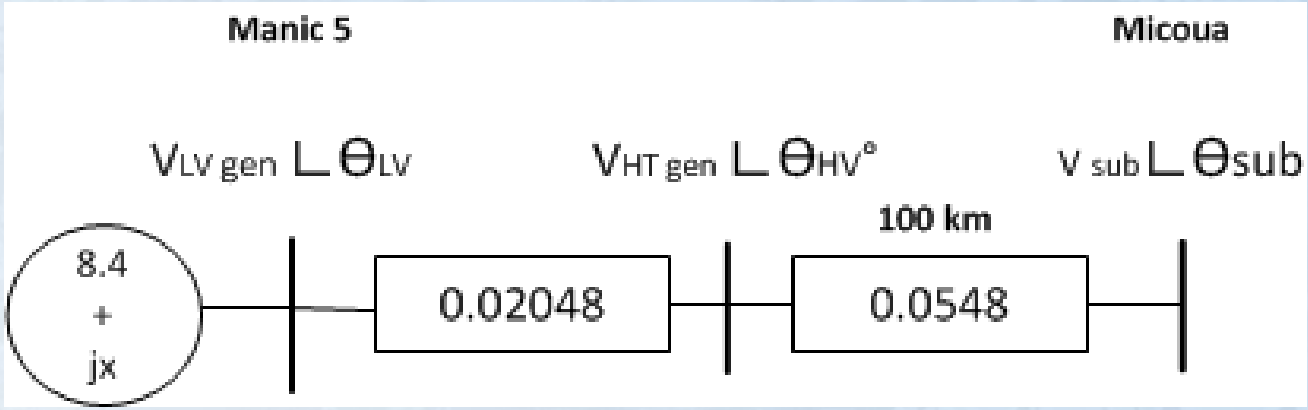
-> The resulting loadability limit for the protection system is too stringent.

Example : Manic 5 generating facility assessment with proposed loadflow criteria

Load flow criterion

-> V_{sub} = 0.85 pu

-> $V_{LV\ gen}$ = 1.05 pu



VLT GEN = 1.05 pu

Vsub Micoua = 0.85 pu

Load flow

S_alt =100%P+j **62%**P Q

V HT GEN = 0.96 pu

Q max line= 0.41 pu

Conditions used to evaluate line protection

- VHT GEN = 0.96 pu
- Qmax_line = 0.41 pu
- Pamx_line = 1 pu

To be used as criteria max loadability limit for Manic 5 line distance protection relays

§ 996.60 Safeguard procedures for imported peanuts.

(a) Prior to arrival of a foreign-produced peanut lot at a port-of-entry, the importer, or customs broker acting on behalf of the importer, shall submit information electronically to the United States Customs and Border Protection, which includes the following: The Customs Service entry number; the container number(s) or other identification of the lot(s); the volume of the peanuts in each lot being entered; the inland shipment destination where the lot will be made available for inspection; and a contact name or telephone number at the destination.

* * * * *

■ 15. In § 996.71:

■ a. Remove paragraph (a);

■ b. Redesignate paragraphs (b) and (c) as paragraphs (a) and (b), respectively;

■ c. Revise newly redesignated paragraph (a); and

■ d. Revise the last sentence in newly redesignated paragraph (b).

The revisions read as follows:

§ 996.71 Reports and recordkeeping.

(a) Each handler and importer shall maintain a satisfactory records system for traceability purposes as defined in § 996.73.

(b) * * * USDA and USDA-approved laboratories shall file copies of all aflatoxin certificates completed by such laboratories with the Southeast Marketing Field Office, Marketing Order and Agreement Division, Specialty Crops Program, AMS, USDA, 1124 1st Street South, Winter Haven, Florida 33880; Telephone (863) 324–3375, Fax: (863) 291–8614, or other address as determined by USDA.

■ 16. Section 996.73 is revised to read as follows:

§ 996.73 Verification of reports.

(a) For the purpose of checking and verifying reports kept by handlers and importers and the operation of handlers and importers under the provisions of this Part, the officers, employees or duly authorized agents of USDA shall have access to any premises where peanuts may be held at any time during reasonable business hours and shall be permitted to inspect any peanuts that meet outgoing quality regulations, so held by such handler or importer and any and all records of such handler with respect to the acquisition, holding, or disposition of all peanuts meeting outgoing quality regulations, which may be held or which may have been disposed by handler.

(b) Reports shall be maintained by the handler for nonconforming products to assure traceability throughout the supply chain. The traceability system must include documented records, which enable a full product history to be produced in a timely manner and must ensure product can be traced forward (raw material to distribution) and backwards from distribution to the warehouse feeding the shelling plant, and ensure that all associated tests and all relevant records have been completed. The traceability system shall include identification of all raw materials, process parameters (for specific lot), packaging and final disposition. The handler shall be able to identify the warehouse in which the peanuts were stored immediately prior to shelling. Traceability must be maintained throughout production runs with specific lot codes, and there shall be complete linkage from raw material receipt through final disposition.

■ 17. In § 996.74:

■ a. Remove paragraph (a)(1);

■ b. Redesignate paragraphs (a)(2) through (7) as paragraphs (a)(1) through (6), respectively;

■ c. Revise newly redesignated paragraphs (a)(3) and (5); and

■ d. Revise paragraph (b).

The revisions read as follows:

§ 996.74 Compliance.

(a) * * *

(3) Commingles failing quality peanuts with certified edible quality peanuts and ships the commingled lot for human consumption use without meeting outgoing quality regulations;

* * * * *

(5) Fails to maintain and provide access to records, pursuant to § 996.71, and the standards for traceability and nonconforming product disposition pursuant to § 996.73, on the reconditioning or disposition of peanuts acquired by such handler or importer; and on lots that meet outgoing quality standards; or

* * * * *

(b) Any peanut lot shipped which fails to meet the outgoing quality standards specified in § 996.31, and is not reconditioned to meet such standards, or is not disposed to non-human consumption outlets as specified in § 996.50, shall be reported by USDA to the Food and Drug Administration and listed on an Agricultural Marketing Service Web site.

■ 18. Section 996.75 is revised to read as follows:

§ 996.75 Effective time.

The provisions of this part, as well as any amendments, shall apply to current crop year peanuts, subsequent crop year peanuts, and prior crop year peanuts not yet inspected, or failing peanut lots that have not met disposition standards, and shall continue in force and effect until modified, suspended, or terminated.

Dated: July 27, 2016.

Elanor Starmer,

Administrator, Agricultural Marketing Service.

[FR Doc. 2016–18116 Filed 7–29–16; 8:45 am]

BILLING CODE 3410–02–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM16–8–000; Order No. 828]

Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is modifying the *pro forma* Small Generator Interconnection Agreement (SGIA). The *pro forma* SGIA establishes the terms and conditions under which public utilities must provide interconnection service to small generating facilities of no larger than 20 megawatts. The Commission is modifying the *pro forma* SGIA to require newly interconnecting small generating facilities to ride through abnormal frequency and voltage events and not disconnect during such events. The specific ride through settings must be consistent with Good Utility Practice and any standards and guidelines applied by the transmission provider to other generating facilities on a comparable basis. The Commission already requires generators interconnecting under the Large Generator Interconnection Agreement to meet such requirements, and it would be unduly discriminatory not to also impose these requirements on small generating facilities. The Commission concludes that newly interconnecting small generating facilities should have ride through requirements comparable to large generating facilities.

DATES: This final rule will become effective October 5, 2016.

FOR FURTHER INFORMATION CONTACT: Monica Taba (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC

20426, (202) 502–6789, *Monica.Taba@ferc.gov*.
Alan Rukin (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–8502, *Alan.Rukin@ferc.gov*.

SUPPLEMENTARY INFORMATION:

Order No. 828

Final Rule

1. In this Final Rule, the Commission modifies the *pro forma* Small Generator Interconnection Agreement (SGIA) originally set forth in Order No. 2006 [1] and revised in Order No. 792 [2] to require small generating facilities interconnecting through the SGIA to ride through abnormal frequency and voltage events and not disconnect during such events.[3] Pursuant to section 206 of the Federal Power Act (FPA), the Commission finds that, given the changes to conditions since the Commission last evaluated whether to impose ride through requirements on small generating facilities, the revisions to the *pro forma* SGIA are necessary to remedy undue discrimination by ensuring that small generating facilities have ride through requirements comparable to large generating facilities.[4]

2. As a result of this Final Rule, small generating facilities are required to not disconnect automatically or instantaneously from the system or equipment of the transmission provider and any affected systems for an under-frequency or over-frequency condition, or an under-voltage or over-voltage condition. Furthermore, the transmission provider must coordinate the small generating facility's protective equipment settings with any automatic load shedding program (*e.g.,* under-frequency load shedding, under-voltage load shedding). The specific ride through settings must be consistent with Good Utility Practice and any standards and guidelines applied by the transmission provider to other generating facilities on a comparable basis. These requirements will apply to new interconnection customers that execute or request the unexecuted filing of an SGIA on or after the effective date of this Final Rule. These requirements will also apply to existing interconnection customers that, pursuant to a new interconnection request, execute or request the unexecuted filing of a new or modified SGIA on or after the effective date of this Final Rule.

I. Background

3. The *pro forma* SGIA establishes the terms and conditions under which public utilities must provide interconnection service to small generating facilities of no larger than 20 megawatts (MW). Currently, the *pro forma* SGIA does not mandate that small generating facilities have the capability to ride through voltage or frequency disturbances.

4. In Order No. 2006, the Commission explored whether voltage ride through requirements proposed for large wind generating facilities should apply to small generating facilities.[5] A commenter during that proceeding asked the Commission to implement ride through standards for small generating facilities similar to those proposed for large generating facilities. However, other commenters responded that special capabilities, such as low voltage ride through, were not needed for any small generating facility, whether wind-powered or not. The Commission concluded that wind generating facilities interconnecting under Order No. 2006 would be small and would have minimal impact on the transmission provider's electric system and, therefore, need not be subject to ride through requirements.[6]

5. More recently, the Commission again addressed these requirements with regard to small generating facilities in Order No. 792.[7] In that proceeding, the Commission proposed to revise section 1.5.4 of the *pro forma* SGIA to address the reliability concern related to automatic disconnection of small generating facilities during over- and under-frequency events, which could become a greater concern at high penetrations of distributed energy resources.[8] The proposed revisions to section 1.5.4 would have required the interconnection customer to design, install, maintain, and operate its small generating facility, in accordance with the latest version of the applicable standards to prevent automatic disconnection during over- and under-frequency events.[9]

6. The Commission declined to adopt this proposed revision in Order No. 792.[10] Instead, the Commission recognized that the Institute of Electrical and Electronics Engineers (IEEE) was, at the time, in the process of amending IEEE Standard 1547, which is an interconnection standard for interconnecting distributed resources with electric power systems that is referenced in the Small Generator Interconnection Procedures.[11] The Commission also noted that IEEE was about to begin a full IEEE Standard 1547 revision process in 2014, where frequency and voltage ride through requirements in the standard were to be evaluated. The Commission concluded that it would continue to monitor the IEEE Standard 1547 revision process and could revise the *pro forma* SGIA as it relates to IEEE Standard 1547 in the future, if necessary.[12]

7. Since the Commission issued Order No. 792, IEEE has completed a partial revision of IEEE Standard 1547, which is IEEE Standard 1547a. IEEE is now in the process of fully revising IEEE Standard 1547. The partially revised standard, IEEE Standard 1547a, permits generating facilities to have wider trip settings compared with IEEE Standard 1547. These wider trip settings allow generating facilities to stay connected to the grid for greater frequency or voltage excursions facilitating their ability to ride through such excursions. IEEE Standard 1547a also permits—but does

[1] *Standardization of Small Generator Interconnection Agreements and Procedures,* Order No. 2006, FERC Stats. & Regs. ¶ 31,180, *order on reh'g,* Order No. 2006–A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification,* Order No. 2006–B, FERC Stats. & Regs. ¶ 31,221 (2006) (Order No. 2006).

[2] *Small Generator Interconnection Agreements and Procedures,* Order No. 792, 145 FERC ¶ 61,159 (2013), *clarified,* Order No. 792–A, 146 FERC ¶ 61,214 (2014) (Order No. 792).

[3] In Order No. 2003, the Commission defined ''ride through'' to mean a generating facility staying connected to and synchronized with the transmission system during system disturbances within a range of over- and under-frequency conditions, in accordance with Good Utility Practice. *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 562 n.88 (2003), *order on reh'g,* Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003–C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008) (Order No. 2003). Reliability Standard PRC–024–1 requires bulk electric system generation to ride through over- and under-voltage conditions.

[4] 16 U.S.C. 824e.

[5] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 24.

[6] *Id.* The penetration of small generating facilities has increased since the Commission analyzed the impact of small generating facilities in Order No. 2006. *See infra* P 8.

[7] Order No. 792, 145 FERC ¶ 61,159.

[8] *Small Generator Interconnection Agreements and Procedures,* Notice of Proposed Rulemaking, 142 FERC ¶ 61,049, at P 46 (2013) (Order No. 792 NOPR). NERC defines distributed energy resources to mean resources that are distributed geographically and not centralized like traditional generation resources. NERC, *Essential Reliability Services Task Force Measures Report,* (Nov. 2015), *http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.*

[9] *Id.*

[10] Order No. 792, 145 FERC ¶ 61,159 at P 220.

[11] *Id.*

[12] *Id.*

not mandate—ride through requirements.[13]

8. Following the Commission's evaluation of the need for ride through requirements for small generating facilities in the Order Nos. 2006 and 792 rulemaking proceedings, the impact of small generating facilities on the grid has changed, and the amount has increased. For example, as the North American Electric Reliability Corporation (NERC) has noted in multiple reports, the mix of generation resources is changing and the high penetration of distributed energy resources will impact the reliability of the electric grid if sufficient care is not taken to mitigate potential adverse impacts.[14] NERC also has found that a lack of coordination between small generating facilities and Reliability Standards can lead to events where system load imbalance may increase during frequency excursions or voltage deviations due to the disconnection of distributed energy resources, which may exacerbate a disturbance on the Bulk-Power System.[15] In addition, the Commission has observed the growth in grid-connected solar photovoltaic generation since the issuance of Order No. 2006 and the growth in small generator interconnection requests driven by state renewable portfolio standards, reductions in cost for solar panels, and deployment of new technologies.[16] Moreover, technology now available to newly interconnecting small generating facilities, such as smart inverters, permits the capability to ride through frequency and voltage disturbances.[17]

[13] IEEE Standard 1547a contains ''must trip'' requirements; it does not have ''must ride through'' requirements. By widening the trip settings, IEEE Standard 1547a permits generating facilities to trip at a later time. This change effectively allows generating facilities to ride through disturbances, but they are not required to do so.

[14] *See* NERC Special Report, *Potential Bulk System Reliability Impacts of Distributed Resources* (Aug. 2011), *http://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf; see also* NERC Integration of Variable Generation Task Force Draft Report, *Performance of Distributed Energy Resources During and After System Disturbance* (Dec. 2013), *http://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%2011/IVGTF17_PC_FinalDraft_December_clean.pdf.*

[15] NERC Essential Reliability Services Report at 21.

[16] *See, e.g.,* Order No. 792, 145 FERC ¶ 61,159 at P 15; Solar Energy Indus. Ass'n, Solar Industry Data, *http://www.seia.org/research-resources/solar-industry-data* (last visited Jul. 5, 2016).

[17] *See* Electric Power Research Institute, *Recommended Settings for Voltage and Frequency Ride Through of Distributed Energy Resources,* 28–29 (May 2015), *http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002006203.*

II. Notice of Proposed Rulemaking

9. On March 23, 2016, the Commission issued a Notice of Proposed Rulemaking that proposed to add new section 1.5.7 to the *pro forma* SGIA,[18] which would require small generating facilities to ride through defined frequency and voltage disturbances.

10. In response to the NOPR, eleven entities submitted substantive comments, which generally support the Commission's proposal.[19] These comments have informed our determinations in this Final Rule.

III. Discussion

11. For the reasons discussed below, we adopt the NOPR proposal and require small generating facilities to ride through abnormal frequency and voltage events comparable to large generating facilities. We find that, given the changes to conditions since the Commission last evaluated whether to impose ride through requirements on small generating facilities, the revisions to the *pro forma* SGIA are necessary to remedy undue discrimination by ensuring that small generating facilities have ride through requirements comparable to large generating facilities.[20] Specifically, since the Commission's last consideration of this issue, IEEE has revised its standards, and IEEE Standard 1547a now provides wider trip settings that allow small generating facilities more leeway to ride through disturbances. In addition, distributed energy resources have had an increasing presence and impact on the electric system. The absence of ride through requirements for small generating facilities increases the risk that an initial voltage or frequency disturbance may cause a significant number of small generating facilities to trip across a particular area or Interconnection, further exacerbating the initial disturbance. Large generating facilities are already subject to ride through requirements to avoid these types of occurrences.[21]

[18] *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities,* 154 FERC ¶ 61,222 (2016) (NOPR).

[19] Appendix A lists the entities that submitted comments and the shortened names used throughout this Final Rule to describe those entities.

[20] 16 U.S.C. 824e. The Commission routinely evaluates the effectiveness of its regulations and policies in light of changing industry conditions to determine if changes in these conditions and policies are necessary. *See, e.g., Integration of Variable Energy Resources,* Order No. 764, FERC Stats. & Regs, ¶ 31,331 (2012).

[21] *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 562 n.88.

12. The Commission acknowledges that some areas have a greater penetration of distributed resources than others at this time. Nevertheless, the Commission believes that the proposed reforms to the *pro forma* SGIA are appropriate on an industry-wide basis now. The Commission continues to affirm that this Final Rule is not intended to interfere with state interconnection procedures or agreements in any way. The *pro forma* SGIA applies only to interconnections made subject to a jurisdictional open access transmission tariff (OATT) for the purposes of jurisdictional wholesale sales. Similar to the approach in Order Nos. 2006 and 792, the Commission hopes that the changes to the *pro forma* SGIA resulting from this Final Rule will be helpful to states when updating their own interconnection rules, but the states are under no obligation to adopt the provisions of the Commission's proposal.[22]

A. Revision of the Pro Forma SGIA

1. NOPR Proposal

13. In the NOPR, the Commission proposed to revise the *pro forma* SGIA to include proposed section 1.5.7, which would require interconnection customers to ensure the frequency ride through capability and the voltage ride through capability of small generating facilities that execute or request the unexecuted filing of interconnection agreements following the effective date of the proposed section 1.5.7. Proposed section 1.5.7 would also require a small generating facility not to disconnect automatically or instantaneously from the system or equipment of the transmission provider and any affected systems for an under-frequency or over-frequency condition, or an under-voltage or over-voltage condition. In addition, the transmission provider must coordinate the small generating facility's protective equipment settings with any automatic load shedding program.

2. Comments

14. The substantive comments filed in response to the NOPR generally support the proposal to modify the *pro forma* SGIA.[23] Commenters agree with the need for fair and equitable treatment between small and large generating

[22] Order No. 792, 145 FERC ¶ 61,159 at P 27; Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 8.

[23] Peak Reliability Comments at 3; Idaho Power Comments at 2; PNM Comments at 1; SoCal Edison Comments at 2; ISO/RTO Council Comments at 6; Trade Associations Comments at 4; Bonneville Comments at 1; EPRI Comments at 7; NERC Comments at 2; PG&E Comments at 2.

facilities, the need for effective protections for system operation while also avoiding increased costs, and the potential to improve system stability and reliability over the coming years by adopting the proposed modifications to the *pro forma* SGIA.[24] Commenters acknowledge the proposal's benefits, stating it will simplify operational conditions, especially considering the rising small generator penetration levels on the distribution system.[25] NERC states that revising the *pro forma* SGIA to impose ride through requirements would be consistent with the results of a number of NERC's reliability assessments.[26] Trade Associations and PNM agree that the absence of ride through requirements for small generating facilities increases the risk that an initial voltage or frequency disturbance may cause a significant number of small generating facilities to trip offline, exacerbating the initial disturbance.[27]

15. Idaho Power claims that if more small generation facilities connect to its system, without the proposed changes to the *pro forma* SGIA, it would become increasingly difficult for it to comply with Reliability Standards PRC–006–2 (Automatic Underfrequency Load Shedding) and BAL–003–1.1 (Frequency Response and Frequency Bias Setting).[28]

16. The ISO/RTO Council recommends that the proposed required characteristics for small generating facilities should be demonstrated ''as tested,'' and that this should be specified in the *pro forma* SGIA section 1.5.7. The ISO/RTO Council notes that demonstrating characteristics ''as tested'' is already required under section 24 of the large generator interconnection agreement (LGIA). The ISO/RTO Council further explains that, while the *pro forma* SGIA does not presently have such language, the ''as tested'' requirement applies to small generating facilities pursuant to the directives in Order No. 2006.[29]

17. Some commenters request that the Commission delay implementation of the Final Rule. While EPRI does not believe that additional action is required for other existing interconnected small generating facilities, EPRI comments that additional reliability studies may be required if aggregate penetration levels increase sufficiently before the modifications to the *pro forma* SGIA and revised IEEE Standard 1547 become effective.[30] EPRI notes the need for timely revision and balloting of IEEE Standard 1547, as well as prompt adoption of the standard.[31] Trade Associations suggest waiting until after key industry standards are approved and the safety and effectiveness of smart inverter technology is validated. [32] Trade Associations request time to allow entities to resolve outstanding concerns such as personnel and asset safety, as well as the ability to effectively coordinate protections systems between the local utility and interconnecting resources.[33] EPRI and IEEE assert that relevant stakeholders, including transmission owners and transmission operators, should engage with the IEEE Standard 1547 revision process to ensure that the final framework and requirements for ride through can be consistently applied to meet individual system needs.[34]

18. Trade Associations claim that the new ride through capability requirements are only possible through smart inverter technology, but point out that key associated specifications contained in the reference standards remain unapproved. Trade Associations explain that distribution feeders are often designed as radial feeders that depend on remote generation to quickly disconnect when the utility source is disconnected. According to Trade Associations, failure to do so may result in unintentional islands which create safety hazards for personnel and customers, as well as liability concerns. Trade Associations caution that directing small generation facilities to ride through disturbances may create islanding conditions and relaxed response to fault conditions.

19. Further, Trade Associations claim that more industry discussion is needed to ensure that small generators' interconnections meet the unique regional utility safety and reliability concerns before the proposed revisions to section 1.5.7 of the *pro forma* SGIA are adopted. Trade Associations suggest that the Commission include the issues in this proceeding in the three regional technical conferences recommended by Edison Electric Institute in Docket No. RM16–6–000.[35]

20. Trade Associations also suggest that the Commission explore how changes made to the *pro forma* SGIA often influence state regulations. Trade Associations note that distribution level interconnections are broadly supported by industry standards and company interconnection rules; and alignment to *pro forma* SGIA may be inappropriate for some state regulations.[36]

3. Commission Determination

21. As discussed above, we find the revisions to the *pro forma* SGIA adopted herein are necessary to remedy treatment that is unjust, unreasonable, and unduly discriminatory and preferential because there is no technical or economic basis to require small and large generating facilities to follow different requirements in regards to voltage and frequency ride through. Our revisions will place similar requirements on large generating facilities and small generating facilities for ride through capabilities. As discussed above, the NOPR proposal received widespread support from commenters. Further, the absence of ride through requirements for small generating facilities may have adverse impacts on the reliability of the electric grid. We find that the lack of ride through requirements for small generating facilities is unduly discriminatory. This is due to the increased presence and impact of small generating facilities, including distributed energy resources, on the electric system, that could create reliability issues if they do not have the capability to ride through voltage or frequency disturbances. Further, improvements in technology, such as smart inverters, make it economically feasible for small generating facilities to ride through voltage and frequency disturbances. We acknowledge that some areas have a greater penetration of distributed resources than others at this time. Nevertheless, we believe that the proposed reforms to the *pro forma* SGIA are appropriate on an industry-wide basis now and that deferred action would not be appropriate.

22. We recognize the work of the IEEE 1547 Working Group, but we determine that there is a pressing need to establish ride through capability requirements at this time because we expect a continuing increase in penetration of small generating facilities. The revisions to the *pro forma* SGIA that we now approve will require the small

[24] SoCal Edison Comments at 2; Peak Reliability Comments at 3; EPRI Comments at 7.

[25] PNM Comments at 2; Trade Associations Comments at 7.

[26] NERC Comments at 4.

[27] PNM Comments at 2; Trade Associations Comments at 7.

[28] Idaho Power Comments at 2.

[29] ISO/RTO Council Comments at 7 (citing Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 59).

[30] EPRI Comments at 7.

[31] *Id.* at 7–8.

[32] Trade Associations Comments at 7–8; EPRI Comments at 7–8.

[33] Trade Associations Comments at 7–8.

[34] EPRI Comments at 7–8.

[35] Trade Associations Comments at 13–14. In Docket No. RM16–6–000, the Commission issued a Notice of Inquiry seeking comment on the need for reforms to its rules and regulations regarding the provision and compensation of primary frequency response.

[36] Trade Associations Comments at 14.

generating facility to implement ride through settings based on a technical standard established by the transmission provider.

23. While Trade Associations point out that IEEE is revising IEEE Standard 1547, the standard does not currently require ride through capability. We are acting now to ensure that all affected jurisdictional small generating facilities will have the ride through capability, as allowed by IEEE Standard 1547a.[37]

24. We are persuaded by the ISO/RTO Council's recommendation to add the ''as tested'' language to section 1.5.7 of the *pro forma* SGIA to harmonize the requirements between the *pro forma* SGIA and the *pro forma* LGIA. Pursuant to this ''as tested'' language, the interconnection customer must provide the successfully completed test results to the transmission provider in a similar manner as in section 24.4 of the *pro forma* LGIA. We believe that the addition of ''as tested'' language does not create an extra burden on either party to an interconnection agreement because the *pro forma* SGIA already includes testing requirements in section 2.1.[38] The ''as tested'' language assures the transmission provider that the required ride through capability can actually be performed by the small generating facility.

25. We hereby adopt new section 1.5.7 of the *pro forma* SGIA showing the changes made to the Commission's proposal in the NOPR as follows:

1.5.7 The Interconnection Customer shall ensure ''frequency ride through'' capability and ''voltage ride through'' capability of its Small Generating Facility. The Interconnection Customer shall enable these capabilities such that its Small Generating Facility shall not disconnect automatically or instantaneously from the system or equipment of the Transmission Provider and any Affected Systems for a defined under-frequency or over-frequency condition, or an under-voltage or over-voltage condition*, as tested pursuant to section 2.1 of this agreement.* The defined conditions shall be in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. . . .

26. We recognize the Trade Associations' concern about potential tension between ride through requirements and anti-islanding protection. Ensuring the safety of utility lineworkers is critically important, and an issue the Commission takes seriously. Based on our consideration of the record, we believe that the ride through requirements adopted herein are technically and safely achievable. In particular, we note that this Final Rule provides significant flexibility for transmission providers to account for potential safety and islanding concerns. For example, the transmission provider can determine specific ride through settings needed to address those concerns so long as those settings are consistent with Good Utility Practice and any standards and guidelines applied to other generating facilities on a comparable basis.

27. Furthermore, we note that islanding and personnel safety are not new issues resulting from this Final Rule; to the contrary, they will continue to be important concerns regardless of the reforms adopted in this Final Rule. Accordingly, we emphasize the importance of implementing ride through requirements through careful coordination between the interconnection customer and the transmission provider, as well as the utilization of appropriate safety procedures for utility personnel, particularly effective and thorough communication for lineworkers in the field, when performing remedial actions following a system disturbance. We support the continued efforts by industry to explore innovative ways to detect island conditions in order to mitigate the risk of unintentional islands.

28. In light of our goal to prevent undue discrimination, we seek to provide guidelines that will be applied to generating facilities on a comparable basis, while allowing for justified differences on a case by case basis. For example, if a transmission provider believes a particular facility has a higher risk of unintentional islanding due to specific conditions on that facility, the revisions to the *pro forma* SGIA will permit the transmission provider to coordinate with the small generating facility to set ride through settings appropriate for those conditions, in accordance with Good Utility Practice and the appropriate technical standards. For facilities with a lower risk of forming an unintentional island, the transmission provider can implement a longer ride through requirement, in accordance with Good Utility Practice and the appropriate technical standards. We believe that the flexibility provided by section 1.5.7 allows for appropriate ride through requirements while recognizing the need to address any safety concerns.

B. Referencing Specific Technical Standards

1. NOPR Proposal

29. In the NOPR, the Commission proposed to avoid prescriptive frequency and voltage ride through requirements to allow for the development of appropriate system-specific standards, noting that the standards can be based on work developed by recognized standards settings bodies, such as IEEE.

2. Comments

30. Commenters request that the proposed rule contain explicit references to standards such as the Reliability Standards and IEEE and UL standards.[39] The ISO/RTO Council states that Reliability Standards already provide requirements for coordination of automatic under-frequency generator tripping with automatic under-frequency load shedding programs that should be incorporated in the new ride through requirements. The ISO/RTO Council suggests that the *pro forma* SGIA explicitly reference Reliability Standard PRC–024 (Generator Frequency and Voltage Protective Relay Settings) and applicable regional Reliability Standards as part of the definition of ''Good Utility Practice'' and for the coordination of automatic generator tripping with automatic load shedding.[40] The ISO/RTO Council also recommends that the *pro forma* SGIA refer to the Reliability Standards and regional Reliability Standards for coordination of automatic generator tripping with automatic load shedding, and as appropriate, permit individual transmission providers to also reference their automatic load-shed program.

31. Commenters assert that specifying certain technical standards would be beneficial for consistent enforceability; specifically, some commenters suggest that the *pro forma* SGIA reference IEEE and UL 1741 standards to describe ''Good Utility Practice.''[41] EPRI and IEEE comment that failure to harmonize ride through requirements with the proposed draft IEEE 1547 requirements may introduce confusion and ultimately delay testing and compliance, exposing the electric system to an increased reliability risk.[42] PNM recognizes that there are challenges to developing specific settings applicable to all small generating facilities.[43] However, PNM states that the Commission should still

[37] As we also explained in the NOPR, the Commission's proposal was not intended to impede the ongoing efforts of the IEEE 1547 Working Group, and we reiterate that point here. NOPR, 154 FERC ¶ 61,222 at P 8 n.19.

[38] *Pro forma* SGIA, Section 2.1 ''Equipment Test and Inspection.''

[39] ISO/RTO Council Comments at 7.

[40] *Id.* at 6–7.

[41] PNM Comments at 3; EPRI Comments at 13; IEEE Comments at 2.

[42] EPRI Comments at 13; IEEE Comments at 2.

[43] PNM Comments at 2.

consider documenting some ride through expectation similar to those outlined in the LGIA requirements. PNM requests that the *pro forma* SGIA revisions consider a minimum ride through duration based on fault clearing times and a minimum voltage. PNM also requests that the Commission specify the location where the frequency and voltage measurements are taken to comply with the requirements, such as the point of interconnection.

32. SoCal Edison observes that the California Public Utilities Commission (CPUC) has established, through its retail Rule 21 tariff, smart inverter requirements for small generators interconnecting to the distribution systems of California's investor owned utilities, and low/high voltage ride through and low/high frequency ride through are part of the new required capabilities for small generators.[44] SoCal Edison explains that the CPUC ordered all investor owned utilities ''to seek approval as may be needed for conforming changes to harmonize their federal wholesale Tariffs interconnection specifications with the revisions to Electric Tariff Rule 21.'' [45]

3. Commission Determination

33. We are not persuaded by commenters' arguments for the need to reference specific technical standards and decline to incorporate by reference any specific standard into the *pro forma* SGIA or to specify ride through duration and voltage and frequency levels. We therefore decline to modify the NOPR proposal in this regard.

34. To accommodate the differences in voltage and frequency ride through capabilities inherent in the different generation technologies, we believe that requiring basic performance expectations without explicitly specifying the duration or voltage and frequency levels allows the flexibility to apply appropriate ride through settings with coordination and approval of the transmission operator. As EPRI and IEEE note, the ride through requirement framework in the draft IEEE Standard 1547 is being structured along ''performance categories'' that take into account the technological differences of various types of small generating facilities. Once finalized, IEEE Standard 1547 may be used as a technical guide to meet the requirements adopted herein. Until revisions to IEEE Standard 1547 are finalized, however, transmission providers and affected interconnection customers must coordinate appropriate alternative frequency and voltage ride through settings.

35. Furthermore, as a pragmatic matter, by setting minimum ride through capability requirements that are not tied to a specific standard, the requirements in section 1.5.7 of the *pro forma* SGIA would remain applicable following any updates from IEEE Standard 1547 or other applicable standards, without having to modify the *pro forma* SGIA each time any such standard is updated.

36. In response to PNM's clarification request, we clarify that the point of interconnection is the appropriate place to measure frequency and voltage to comply with the ride through requirements.

C. Regional Differences

1. NOPR Proposal

37. The Commission proposed to permit RTOs and ISOs to seek ''independent entity variations'' from the proposed revisions to the *pro forma* SGIA.

2. Comments

38. Multiple commenters support the Commission's proposal to permit RTOs and ISOs to seek ''independent entity variations'' from the proposed revisions to the *pro forma* SGIA.[46]

39. Trade Associations request that the Commission also affirm the ability of transmission providers that are not members of RTOs or ISOs to seek variations from the *pro forma* SGIA to ensure consistency with regional reliability requirements. Trade Associations explain that differences in resource penetration and configuration (such as state renewable portfolio standards or wind generation in remote locations) have led to regional reliability requirements. Trade Associations note that the Commission recognized in Order No. 2003 that such regional reliability requirements might justify variations to *pro forma* interconnection agreements and procedures.[47] SoCal Edison believes that, to the extent that some regions may need additional time to implement the proposed ride through requirements on small generating facilities, the Commission should grant such time.[48]

3. Commission Determination

40. We adopt the NOPR proposal and permit ISOs and RTOs to seek ''independent entity variations'' from revisions to the *pro forma* SGIA.[49] Also, as proposed in the NOPR, if a transmission provider seeks a deviation from section 1.5.7 of the *pro forma* SGIA, it must demonstrate that the deviation is consistent with or superior to the principles set forth in this Final Rule.

41. In addition, we clarify that we will also consider requests for ''regional reliability variations,'' provided that such requests are supported by references to regional Reliability Standards, explain why these regional Reliability Standards support the requested variation, and include the text of the referenced Reliability Standards.[50] While some regions currently have greater penetration of small generation facilities than others, we are acting now to set a national minimum ride through capability before future increases in deployment of small generation facilities.

IV. Compliance and Implementation

42. Section 35.28(f)(1) of the Commission's regulations requires every public utility with a non-discriminatory open access transmission tariff OATT on file to also have an SGIA on file with the Commission.[51]

43. We reiterate that the requirements of this Final Rule apply to all newly interconnecting small generating facilities that execute or request the unexecuted filing of an SGIA on or after the effective date of this Final Rule as well as existing interconnection customers that, pursuant to a new interconnection request, execute or request the unexecuted filing of a new or modified SGIA on or after the effective date.

44. We require each public utility transmission provider that has an SGIA within its OATT to submit a compliance filing within 65 days following publication in the **Federal Register**.[52] The compliance filing must demonstrate that it meets the requirements set forth in this proposal.

45. The Commission recently issued Order No. 827, a final rule in Docket No. RM16–1–000, directing transmission providers to submit SGIA revisions

[44] SoCal Edison Comments at 3.

[45] *Id.*

[46] Trade Associations Comments at 12–13; SoCal Edison Comments at 4; ISO/RTO Council Comments at 6.

[47] Trade Associations Comments at 12–13.

[48] SoCal Edison Comments at 4.

[49] *See* Order No. 792, 145 FERC ¶ 61,159 at P 274 (citing Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 822–827).

[50] *See id.* P 273 (citing Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 546).

[51] 18 CFR 35.28(f)(1).

[52] For purposes of this Final Rule, a public utility is a utility that owns, controls, or operates facilities used for transmitting electric energy in interstate commerce, as defined by the FPA. *See* 16 U.S.C. 824(e). A non-public utility that seeks voluntary compliance with the reciprocity condition of an OATT may satisfy that condition by filing an OATT, which includes an SGIA.

related to reactive power requirements to the Commission.[53] Those compliance filings are due to the Commission on September 21, 2016. To facilitate administrative efficiency, we will require the compliance filings for this Final Rule and Order No. 827 to be filed in one combined filing. Once this Final Rule is published in the **Federal Register**, the Commission will provide a short extension to the compliance dates in both proceedings such that the compliance dates are the same.

46. As discussed above, we are not requiring changes to interconnection agreements that were executed prior to the effective date of this Final Rule. Instead, the requirements of this Final Rule apply to newly interconnecting small generating facilities that execute or request the unexecuted filing of an interconnection agreement on or after the effective date. The requirements of this Final Rule also apply to existing small generating facilities that, pursuant to a new interconnection request, require new or modified interconnection agreements that are executed or requested to be filed unexecuted on or after the effective date.

47. Some public utility transmission providers may have provisions in their existing SGIAs or other document(s) subject to the Commission's jurisdiction that the Commission has deemed to be consistent with or superior to the *pro forma* SGIA or are permissible under the independent entity variation standard or regional reliability standard.[54] Where these provisions would be modified by this Final Rule, public utility transmission providers must either comply with this Final Rule or demonstrate that these previously-approved variations continue to be consistent with or superior to the *pro forma* SGIA as modified by this Final Rule or continue to be permissible under the independent entity variation standard or regional reliability standard.[55]

48. We find that transmission providers that are not public utilities must adopt the requirements of this Final Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[56]

V. Information Collection Statement

49. The following collection of information contained in this Final Rule is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995.[57] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[58] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this Final Rule will not be penalized for failing to respond to this collection of information unless the collection of information displays a valid OMB control number.

50. The reforms adopted in this Final Rule revise the Commission's *pro forma* SGIA in accordance with section 35.28(f)(1) of the Commission's regulations.[59] This Final Rule applies to all newly interconnecting small generating facilities that execute or request the unexecuted filing of an SGIA on or after the effective date of this Final Rule as well as existing interconnection customers that, pursuant to a new interconnection request, execute or request the unexecuted filing of a new or modified SGIA on or after the effective date, to ensure frequency ride through capability and voltage ride through capability in accordance with good utility practice and consistent with any standards and guidelines that are applied to other generating facilities in the balancing authority area on a comparable basis. The reforms adopted in this Final Rule would require filings of SGIAs with the Commission. The Commission anticipates the revisions required by this Final Rule, once implemented, will not significantly change existing burdens on an ongoing basis. With regard to those public utility transmission providers that believe that they already comply with the revisions adopted in this Final Rule, they can demonstrate their compliance in the filing required 65 days after the effective date of this Final Rule. The Commission will submit the proposed reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[60]

51. While the Commission expects the revisions adopted in this Final Rule will provide significant benefits, the Commission understands that implementation would entail some costs. The Commission solicited comments on the accuracy of provided burden and cost estimates and any suggested methods for minimizing the respondents' burdens. The Commission did not receive any comments concerning its burden or cost estimates. As explained above, we will require the compliance filings for this Final Rule and Order No. 827 to be filed in one combined filing. We expect that this will reduce the burden on public utility transmission providers at the time the Commission gives notice of the extension of the compliance date and requirement to combine compliance filings.

Burden Estimate: The Commission believes that the burden estimates below are representative of the average burden on respondents. The estimated burden and cost for the requirements adopted in this Final Rule follow.[61]

[53] *Reactive Power Requirements for Non-Synchronous Generation,* Order No. 827, 81 FR 40,793 (Jun. 23, 2016), 155 FERC ¶ 61,277 (2016).

[54] *See* Order No. 792, 145 FERC ¶ 61,159 at P 270.

[55] *See* 18 CFR 35.28(f)(1)(i).

[56] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,760–63 (1996), *order on reh'g,* Order No. 888–A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[57] 44 U.S.C. 3507(d).

[58] 5 CFR 1320.11.

[59] 18 CFR 35.28(f)(1).

[60] 44 U.S.C. 3507(d).

[61] Commission staff estimates that industry is similarly situated in terms of hourly cost (wages plus benefits). Based on the Commission 2016 average cost (wages plus benefits), $74.50/hour is used.

FERC 516A REVISIONS IN RM16–8

	Number of respondents [62] (1)	Annual number of responses per respondent (2)	Total number of responses (1)*(2)=(3)	Average burden (hrs.) & cost ($) per response (4)	Total annual burden hrs. & total annual cost ($) (3)*(4)=(5)
Conforming SGIA changes to incorporate revisions.	118	1	118	7.5 hrs.; $558.75	885 hrs.; $65,932.50
Total	.....	.....	118	7.5 hrs.; $558.75	885 hrs.; $65,932.50

Cost to Comply: The Commission has projected the additional cost of compliance as follows: [63]

- Year 1: $65,932.50 for all affected entities ($558.75/utility)
- Year 2 and subsequent years: $0

After implementation in Year 1, the reforms proposed in this Final Rule would be complete.

Title: FERC–516A, Standardization of Small Generator Interconnection Agreements and Procedures.

Action: Revision of currently approved collection of information.

OMB Control No.: 1902–0203.

Respondents for This Rulemaking: Businesses or other for profit and/or not-for-profit institutions.

Frequency of Information: One-time during Year 1.

Necessity of Information: The Commission adopts changes to the *pro forma* SGIA in order to more efficiently and cost-effectively interconnect generating facilities no larger than 20 MW (small generating facilities) to Commission-jurisdictional transmission systems. The purpose of this Final Rule is to revise the *pro forma* SGIA so small generating facilities can be reliably and efficiently integrated into the electric grid and to ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. This Final Rule seeks to achieve this goal by amending the *pro forma* SGIA to include new section 1.5.7.

Internal Review: The Commission has reviewed the changes and has determined that the changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements.

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

53. Comments on the collection of information and the associated burden estimate in the Final Rule should be sent to the Commission in this docket and may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission], at the following email address: *oira_submission@omb.eop.gov.* Please reference OMB Control No. 1902–0203 and the docket number of this rulemaking in your submission.

VI. Regulatory Flexibility Act

54. The Regulatory Flexibility Act of 1980 (RFA) [64] generally requires a description and analysis of rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

55. The Small Business Administration (SBA) revised its size standards (effective January 22, 2014) for electric utilities from a standard based on megawatt hours to a standard based on the number of employees, including affiliates. Under SBA's standards, some transmission owners will fall under the following category and associated size threshold: Electric bulk power transmission and control, at 500 employees.[65]

56. The Commission estimates that the total number of public utility transmission providers that would have to modify the SGIAs within their currently effective OATTs is 118. Of these, the Commission estimates that approximately 43% are small entities. The Commission estimates the average cost to each of these entities will be minimal, requiring on average 7.5 hours or $558.75. According to SBA guidance, the determination of significance of impact ''should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors.'' [66] The Commission does not consider the estimated burden to be a significant economic impact. As a result, the Commission certifies that the reforms adopted in this Final Rule would not have a significant economic impact on a substantial number of small entities.

VII. Environmental Analysis

57. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[67] As we stated in the NOPR, the Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for the revisions adopted in this Final Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and

[62] Number of Applicable Registered Entities.

[63] The costs for Year 1 would consist of filing proposed changes to the *pro forma* SGIA with the Commission within 65 days of the effective date of the final revision plus initial implementation. The Commission does not expect any ongoing costs beyond the initial compliance in Year 1.

[64] 5 U.S.C. 601–612.

[65] 13 CFR 121.201, Sector 22 (Utilities), NAICS code 221121 (Electric Bulk Power Transmission and Control).

[66] U.S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act,* at 18 (May 2012), *https://www.sba.gov/sites/default/files/advocacy/rfaguide_0512_0.pdf.*

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

charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[68] The revisions adopted in this Final Rule would update and clarify the application of the Commission's standard interconnection requirements to small generating facilities.

58. Therefore, this Final Rule falls within the categorical exemptions provided in the Commission's regulations, and as a result neither an Environmental Impact Statement nor an Environmental Assessment is required.

VIII. Document Availability

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

60. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.

61. User assistance is available for eLibrary and the Commission's Web site during normal business hours from the Commission's Online Support at (202) 502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

IX. Effective Date and Congressional Notification

62. The Final Rule is effective October 5, 2016. However, as noted above, the requirements of this Final Rule will apply only to all newly interconnecting small generating facilities that execute or request the unexecuted filing of an SGIA on or after the effective date of this Final Rule as well as existing interconnection customers that, pursuant to a new interconnection request, execute or request the unexecuted filing of a new or modified SGIA on or after the effective date. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this Final Rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. This Final Rule is being submitted to the Senate, House, Government Accountability Office, and Small Business Administration.

By the Commission.

Issued: July 21, 2016.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

Note: The following Attachment will not appear in the Code of Federal Regulations.

Appendix A—List of Substantive Commenters (RM16–8–000)

Bonneville Bonneville Power Administration
Trade Associations Edison Electric Institute/American Public Power Association/Large Public Power Council/National Rural Electric Cooperative Association
EPRI Electric Power Research Institute
Idaho Power Idaho Power Company
IEEE Institute of Electrical and Electronics Engineers
ISO/RTO Council ISO/RTO Council
NERC North American Electric Reliability Corporation
PG&E Pacific Gas and Electric Company
Peak Reliability Peak Reliability
PNM Public Service Company of New Mexico
SoCal Edison Southern California Edison Company

In addition, Entergy Services, Inc. submitted non-substantive comments.

[FR Doc. 2016–17843 Filed 7–29–16; 8:45 am]

BILLING CODE 6717–01–P

[68] 18 CFR 380.4(a)(15).

DEPARTMENT OF LABOR

Employment and Training Administration

20 CFR Part 620

RIN 1205–AB63

Federal-State Unemployment Compensation Program; Middle Class Tax Relief and Job Creation Act of 2012 Provision on Establishing Appropriate Occupations for Drug Testing of Unemployment Compensation Applicants

AGENCY: Employment and Training Administration, Labor.

ACTION: Final rule.

SUMMARY: The Employment and Training Administration (ETA) of the U.S. Department of Labor (Department) is issuing this final rule to establish, for State Unemployment Compensation (UC) program purposes, occupations that regularly conduct drug testing. These regulations implement the Middle Class Tax Relief and Job Creation Act of 2012 (the Act) amendments to the Social Security Act (SSA), permitting States to enact legislation that would allow State UC agencies to conduct drug testing on UC applicants for whom suitable work (as defined under the State law) is available only in an occupation that regularly conducts drug testing (as determined under regulations issued by the Secretary of Labor (Secretary)). States may deny UC to an applicant who tests positive for drug use under these circumstances. The Secretary is required under the SSA to issue regulations determining those occupations that regularly conduct drug testing.

DATES: *Effective Date:* This final rule is effective September 30, 2016.

FOR FURTHER INFORMATION CONTACT: Suzanne Simonetta, Office of Unemployment Insurance, ETA, U.S. Department of Labor, 200 Constitution Avenue NW., Room S–4524, Washington, DC 20210; telephone: (202) 693–3225 (this is not a toll-free number); email: *simonetta.suzanne@dol.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

On October 9, 2014, The Department published a Notice of Proposed Rulemaking (NPRM) concerning occupations that regularly conduct drug testing at 79 FR 61013. The Department invited comments through December 8, 2014.

II. General Discussion of the Final Rule

On February 22, 2012, President Obama signed the Act, Public Law 112–96. Title II of the Act amended section 303, SSA, to add a new subsection (l) permitting States to drug test UC applicants as a condition of UC eligibility under two circumstances. The first circumstance is if the applicant was terminated from employment with the applicant's most recent employer because of the unlawful use of a controlled substance. (Section 303(l)(1)(A)(i), SSA.) The second circumstance is if the only available suitable work (as defined in the law of the State conducting the drug testing) for an individual is in an occupation that regularly conducts drug testing (as determined in regulations by the Secretary). If an applicant who is tested for drug use under either circumstance tests positive, the State may deny UC to

FERC Order 829
Revised Critical Infrastructure Protection Reliability Standards (Supply Chain)

Guy V. Zito
NPCC RSC
August 10-11, 2016

CIP Supply Chain

- **Issued July 21, 2016, (Order is Effective 60 days after publication in Fed. Register)**
  - Develop a new or modified Reliability Standard that addresses supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations. NERC to submit the new or modified Reliability Standard within one year of the effective date of this Final Rule
  - SC approved solicitation of SDT nominations open through August 18, 2016
  - **NERC to present industry approved standard to BOT August 2017**

CIP Supply Chain

- Each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations. Four attributes (or equally efficient and effective alternatives):
  - **(1) Software Integrity and Authenticity**
  - **(2) Vendor Remote Access**
  - **(3) Information System Planning**
  - **(4) Vendor Risk Management and Procurement Controls**

CIP Supply Chain

- **Software Integrity and authenticity** (listed as a "must" in the Order):
  - the identity of the software publisher for all software and patches that are intended for use on BES Cyber Systems
  - the integrity of the software and patches before they are installed in the BES Cyber System environment

CIP Supply Chain

- **Vendor Remote Access to BES Cyber Systems** (listed as a "must in the Order):
  - address responsible entities logging and controlling all third-party (i.e., vendor) initiated remote access sessions
  - ability to rapidly disable remote access sessions in the event of a system breach
  - Remote access should be operator controlled, time limited, and procedurally similar to "lock out, tag out."

CIP Supply Chain

- **Information System Planning and Procurement** (listed as a "must" in the Order)
  - address how a responsible entity will include security considerations as part of its information system planning and system development lifecycle processes
  - CIP Senior Manager (or Delegate) identification and documentation of the risks of proposed information system planning and system development actions
  - supports, where appropriate, the need for strategic technology refreshes as recommended by ICS-CERT in response to the 2015 Ukraine cybersecurity incident

CIP Supply Chain

- **Vendor Risk Management and Procurement Controls** (listed as a "must" in the Order)
  - address the provision and verification of relevant security concepts in future contracts for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations (5 attributes)
    - vendor security event notification processes
    - vendor personnel termination notification for employees with access to remote and onsite systems
    - product/services vulnerability disclosures, such as accounts that are able to bypass authentication or the presence of hardcoded passwords
    - coordinated incident response activities
    - other related aspects of procurement

- Entities will not be responsible for vendor errors beyond the scope of the controls implemented to comply with the Reliability Standards
- NERC to establish provisions addressing compliance obligations in a manner that avoids shifting liability from a vendor for its mistakes to a responsible entity
- Require a CIP Senior Manager to review and approve the controls adopted to meet the specific security objectives identified in the Reliability Standard at least every 15 months
- CIP Senior Manager should consider any guidance issued by NERC, the U.S. Department of Homeland Security (DHS) or other relevant authorities for the planning, procurement, and operation of industrial control systems and supporting information systems equipment since the prior approval, and identify any changes made to address the recent guidance

NPCC Compliance Committee Development of Implementation Guidance

8/10/2016 Reliability Standards Committee Meeting

NPCC, Inc.

NERC Compliance Guidance Policy

- **Purpose** – Develop approaches useful in providing guidance for implementing Standards
- Two Types of Guidance
  - Implementation Guidance
    - During development of Standard
    - After final Ballot for Standard approved
  - CMEP Practice Guides

NPCC, Inc.

Pre-Qualified Organizations

- 18. Regional Entity Stakeholder Committees
  - NPCC Compliance Committee is a Regional Entity Stakeholder Committee

NPCC, Inc.

Requesting Implementation Guidance from CC

- Any CC member or NPCC may request the CC develop and/or vet an example proposed for Implementation Guidance
- To make such a request, use the NPCC Implementation Guidance Request Form
- CC Chair/vice-chair notifies CC of request

NPCC, Inc.

CC Development of Implementation Guidance

- CC Selects Implementation Guidance Development Team (IGDT)
  - Must be CC member or NPCC staff
  - IGDT must include at least one NPCC Staff member
- 45 Day expected timeline

NPCC, Inc.

CC Vetting of Implementation Guidance

- All CC members and NPCC have 30 days to provide written comment on Draft Implementation Guidance
- If no comments or comments supportive
  - CC vote
- If comments recommending changes or opposition, IGDT responds to comments
  - CC *may* vote after IGDT response
- All votes are in accordance with CC Scope of Work

NPCC, Inc.

CC Vetting of Implementation Guidance

- Continued opposition from any CC member or NPCC may be documented and provided to the ERO
- Upon approval by CC, NERC Compliance Guidance Policy Implementation Guidance Submittal Form is submitted to ComplianceGuidance@nerc.net

Questions?

NPCC, Inc.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Guidance Policy

November 5, 2015

RELIABILITY | ACCOUNTABILITY






3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
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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.

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Risk Profile #1: Changing Resource Mix

Statement of the Risk

The change to the resource mix is accelerating due to fuel costs, subsidies, and federal, state, and provincial policies. Transmission planners, balancing authorities, and system operators of the Bulk-Power System (BPS) may not always have sufficient time needed to develop and deploy plans to mitigate reliability considerations with various resource additions and retirements.

Level of Risk

High Priority

Descriptors of the Risk

1. The rate of change (penetration rates of certain resources) and the type of change (the specific resources) are influenced by state, provincial, and federal initiatives, which, at times, impact one region, province, or state more than another. Over time, regulatory initiatives will likely alter the nature, investment needs, and dispatch of generation with the replacement of large rotating synchronous central station generators with natural gas fired generation, renewable forms of asynchronous generation, and other technologies. Planners and operators may not have the requisite time to reliably integrate these inputs and make necessary changes.
2. The ability of regulators and industry to foresee and address reliability issues associated with the rate and type of change to the resource mix is increasingly complicated by:
    a. The lack of ancillary services, such as the essential reliability services (ERS) (voltage control and reactive support, frequency response, ramping) on the BPS, which is exacerbated by the retirement of many large rotating synchronous central station generating units; and
    b. The integration of large amounts of new technology resources, distributed energy resources, and behind-the-meter resources, and the lack of low voltage ride through, inaccurate load data to accurately forecast anticipated demand, and inability to see and control distributed energy resources.

Recommendations for Mitigating the Risk

Near-term (1–2 year timeframe):

1. NERC, in collaboration with the Regional Entities and industry, should proactively conduct interconnection-wide technical studies, such as frequency and inertia response, voltage support, short-circuit analysis, inter-area oscillation assessment and electric and gas dependency studies. Also, through a stakeholder outreach and input process, inform and educate policy makers,

regulators, and the industry of reliability effects and interconnection requirements for the changing resource mix.

2. NERC should develop an effective means to gather data and insights into the distributed networks, including distributed energy resources (i.e., customer, distribution, or otherwise), and formulate plans to achieve effective transparency and control such that implications to the BPS can be better understood.
3. Expand the collaboration, through the technical committees, with the Regional Transmission Operators (RTO)/Independent System Operators (ISOs) Council, Balancing Authorities in nonmarket areas, and FERC on ERS recommendations for effective implementation as they emerge.
4. NERC should continue to provide independent technical assessments of proposed regulatory rules or proposed statutes at state, provincial, or federal levels related to the changing resource mix, as well as any significant market rules addressing the changing resource mix with a focus on any potential impacts to reliability.

Mid-term (3–5 year timeframe):

1. Regulators should engage in high-level collaboration among market operators (RTOs/ISOs), and provinces and states to establish long-term strategies for aligning policies with reliability needs.

Long-term (greater than 5-year timeframe):

1. NERC and the technical committees should continue working with industry stakeholders, FERC, and state and provincial regulators regarding reliability attributes essential to support the long-term reliability of the BPS, including controls available for variable energy/renewable resources, aggregate effects of distributed energy resources such as small end-use customer resources, distributed energy resource performance, synchronous generation retirement effects, and other essential aspects of reliable service.

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Risk Profile #2: Bulk-Power System Planning

Statement of the Risk

Bulk-Power System (BPS) planning is transitioning from centrally planned and constructed resources based on forecasted load growth and reliability projects to more reactive planning based on the integration of new resources and technologies driven by policies and incentives. Due to the lack of visibility, certainty, and speed that these resources are being integrated, planners currently lack the ability to update or create system models and scenarios of potential future states to identify system needs. Planners may not have sufficient time to implement mitigation plans or reliability upgrades to address likely scenarios, driving the need for more real-time operating procedures.

Level of Risk

High Priority

Descriptors of the Risk

1. Planning and operating the BPS is becoming more complex due to:
    a. The increased and accelerated rate of plant retirements, especially conventional synchronous generation, coupled with the increasing integration of renewable, distributed, and asynchronous resources.
    b. Increased risks with the transition from a balanced resource portfolio, including a number of different fuel-types, to one that is predominately natural gas and variable energy resources.
2. Planners need to evaluate BPS stability, including consideration of inertia and frequency response, voltage support (adequate dynamic and static reactive compensation), and ramping constraints due to the timing and dynamic performance of the new resource mix that changes throughout the day. Planners need a complete understanding of all pertinent resources and their characteristics to identify system reliability needs and develop mitigation plans.
3. Ability to perform accurate long-term planning assessments is more difficult due to:
    a. The uncertainty and lack of visibility into load composition and resource mix, along with imprecise or evolving models;
    b. An increasing need for transmission and system planning activities to include distributed energy resources; however, limited data availability, information sharing, and lack of coordination for some organizations hinder the ability of planners to complete this analysis;
    c. The increased deployment of distributed energy resources within the distribution or behind-the-meter configurations, with will impact how the BPS responds;

d. Uncoordinated integration of controllable device settings and power electronics installed to stabilize the system; and

e. Complex load model and interaction with power electronics devices on a large scale at the distribution level that may affect BPS operations during disturbances (e.g., fault-induced delayed voltage recovery).

4. Common mode or single point of failures, such as fuel delivery systems, are emerging or have yet to be determined or evaluated.

Recommendations for Mitigating the Risk

Near-term (1–2 year timeframe):

1. Coordinate and work with industry and manufacturers and developers of asynchronous resources to develop and make available accurate dynamic models.
2. Identify the type and frequency of information needed to exchange between BPS and distribution system operators in areas of significant penetration of distributed or behind-the-meter resources and develop guidance documents.
3. Develop guidelines and best practices for developing and maintaining accurate system models that include the resources, load, and controllable devices providing the essential reliability service (ERS). This would add the benchmarking of dynamic models with Phasor Measurement Units (PMU) measurements based on actual system response to disturbance.

Mid-term (3–5 year timeframe):

1. NERC should continue to collaborate with Planning Coordinators to expand development of interconnection-wide models commensurate with expected dispatches reflecting dynamic response supporting the ability to conduct long-term planning assessments.
2. Continue to assess the ERS report to determine if the current body of planning Reliability Standards is sufficient to address the essential services and wide area coordination.
3. NERC should collaborate with Planning Coordinators to assess fuel delivery issues and develop methods to assess this delivery in long-term planning studies.

Long-term (greater than 5-year timeframe):

1. Improve load forecasting, generator modeling, and coordination between BPS and distribution system planners and operators.
2. Encourage vendors of power system simulation software to develop programs to enhance dynamic load modeling capabilities.

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Risk Profile #3:
Resource Adequacy and Performance

Statement of the Risk

The resource mix and its delivery is transforming from large, remotely-located coal and nuclear-fired power plants, towards gas-fired, renewable energy-limited, and distributed energy resources. These changes in the generation resource mix and new technologies are altering the operational characteristics of the grid and will challenge system planners and operators to maintain reliability. Failure to take into account these changing characteristics and capabilities can lead to insufficient capacity and essential reliability services (ERS) (sometimes called "ancillary services") to meet customer demands.

Level of Risk

High Priority

Descriptors of the Risk

1. The traditional methods of assessing resource adequacy may not accurately or fully reflect the new resource mix ability to supply energy and reserves for all operating conditions.
2. Forecasting Bulk-Power System (BPS) resource requirements to meet customer demand becomes difficult due to penetration of behind-the-meter resources which, without sufficient visibility, can mask the customer electric energy use and the operating characteristics of distributed resources.
3. Conventional steam resources that operate infrequently due to economics may not operate reliably when dispatched for short hot or cold peak demand periods.
4. Historic methods of assessing and allocating ancillary services such as regulation, ramping, and voltage support may not ensure ERS or sufficient contingency reserves are available at all times during real-time operations.
5. Fuel constraints and environmental limitations may not be reflected in resource adequacy assessments.

Recommendations for Mitigating the Risk

Near-term (1–2 year timeframe):

1. NERC and the industry should continue to develop better modeling and more predictive methods to evaluate resource adequacy. This includes continued sharing of emerging trends and insights from assessments for effective resource planning and operating models. Adequacy and capacity may include augmenting the measurements of ERS, coordination of controls, balancing load with generation regardless of the location of resources, and energy adequacy in light of installed and available capacity from variable generation.

2. Assess and develop mitigation recommendations as necessary to address single points of failure, such as fuel contingencies, that will result in large resource outages.
3. NERC and the industry should continue to expand the use of probabilistic approaches to develop resource adequacy measures that reflect variability and overall reliability characteristics of the resources and composite loads.
4. NERC should assess resource adequacy under scenarios other than seasonal peak capacity due to the seasonal variation of the operating capability of the resource mix.
5. Promote improved unit retirement forecast models to generate scenarios for planning studies.
6. The industry should evaluate opportunities to develop more accurate short-term load forecast models.
7. NERC should develop new measures of reliability beyond reserve margins including measures on sufficiency of ERS.
8. Continue to assess vulnerabilities from fuel availability as part of evaluating adequacy and capability to deliver resources.
9. Analyze data requirements necessary to ensure there is sufficient detail on the capability and performance of the BPS and distribution system. The industry should gather data beyond simple demand forecasts and expand to identify resource capacity, location, and ERS capability.

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Risk Profile #4:
Asset Management and Maintenance

Statement of the Risk

As the system ages and operations are modified, asset management programs also change. Failure to properly commission, operate, maintain, prudently replace, and upgrade Bulk-Power System (BPS) assets, such as those nearing their end-of-life, could result in more frequent and wider-spread outages initiated or exacerbated by equipment failures.

Level of Risk

Moderate Priority

Descriptors of the Risk

1. Lack of visibility of common-mode failures.
   a. Delayed or no industry-wide notice when new issues arise.
   b. No trend information readily available.
2. Extended outage time needed to replace major equipment.
3. Lack of sufficient analytics and awareness of inadequately maintained or conditioned equipment at or above minimum standards or requirements.
4. Barriers for proactive equipment replacement programs.
5. Level of awareness and understanding of priority system upgrades.
6. Increasingly complex protection systems that must be managed and maintained to prevent or mitigate events.

Recommendations for Mitigating the Risk

Near-term (1–2 year timeframe):

1. Increase the use of NERC's Alert program to provide more detail on information requests from industry on specific assets, earlier dissemination of detailed reports, and potential follow-up activities involving maintenance and management of assets.
2. Improve the gathering of data for equipment failure modes and improve the dissemination to the industry.
3. Establish effective communication interfaces between industry and equipment supply chain to raise awareness of equipment or manufacture defects.

4. Continue to conduct webinars on equipment event lessons learned, equipment maintenance, and seasonal preparedness.
5. Continue to evaluate performance trends using additional data collected by event analysis to extract insights, issues, and trends for dissemination across industry participants.
6. Track the number of successful activities, maintenance, and reliability issues to gain insights on trends in effective asset maintenance.
7. Engage industry groups and trade press to increase dissemination of best practices.
8. NERC should evaluate and enhance the data gathered in its Generation and Transmission Availability Data Systems (GADS and TADS) so analysis can provide sufficient granularity to identify equipment failure and performance trends, which can be used to inform asset owners of focal points for asset management programs.

Mid-term (3–5 year timeframe):

1. Coordinate with the forums, research organizations, and technical committees to establish an industry-wide Asset Management and Maintenance Strategic Plan to identify technologies that may aid in condition monitoring, failure prevention, spare sharing, and recovery.
2. Coordinate with the US, Canadian, and Mexican energy agencies, and industry to support power transformer reserve programs.
3. Provide policy framework to review recovery of upgrade and maintenance costs for reliability purposes. Implement recommendations on skills gaps to ensure appropriately skilled workers are maintaining equipment.

Long-term (greater than 5-year timeframe):

1. The industry should implement recommendations from the Asset Management and Maintenance Strategic Plan developed in the mid-term.

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Risk Profile #5: Human Performance and Skilled Workforce

Statement of the Risk

The Bulk-Power System (BPS) is becoming more complex, and as the industry faces turnover in technical expertise, industry will have difficulty staffing and maintaining necessary skilled workers. In addition, inadequate human performance (HP) makes the grid more susceptible to both active and latent errors, negatively affecting reliability. HP weaknesses may hamper an organization's ability to identify and address precursor conditions to promote effective mitigation and behavior management.

Level of Risk

Moderate Priority

Descriptors of the Risk

1. Organizations not implementing improvements based on past events or experiences can hinder future operations improvements; gaps in skillsets or organizational improvement must be a priority.
2. Turnover of key skilled or experienced workers (e.g., relay technicians, operators, engineers, IT support, and substation maintenance) will lead to more protection system misoperations.
3. Lack of training programs prevent closing skillset gaps quickly.
4. Inadequate management oversight or controls leads to organizational weaknesses and inefficiencies.
5. Ineffective corrective actions leads to repeated human performance errors.
6. Legacy systems and new technology result in disparity in the skillsets needed for BPS reliability.

Recommendations for Mitigating the Risk

Near-term (1–2 year timeframe):

1. In partnership with the North American Transmission Forum's (NATF's) HP Practice Group and Regional HP groups, NERC should expand its communication of insights throughout the industry regarding best practices for increasing HP effectiveness by publishing lessons learned practices, conducting the NERC HP conference, and holding other related workshops.
2. NERC should encourage industry and key trade associations to determine the extent of expected skills gaps and develop recommendations to address the skills gaps (curricula, programs, industry support).

3. NERC should enhance the HP aspects of lessons learned, advisories, and Alerts, and NERC should also disseminate detailed event or incident reports in a timely and secure fashion.
4. In coordination with the technical committees, consider expanding continuing education programs to include HP training.
5. NERC and the industry should promote adoption of NERC cause codes to establish a common understanding of HP triggers, collect and evaluate trends in data, and develop metrics.
6. Explore use of the near-miss database.

Mid-term (3–5 year timeframe):

1. Consider and implement high value recommendations developed to address skills gaps identified in the short-term mitigation mentioned in the 1–2 year timeframe.
2. Encourage and promote robust HP programs and controls throughout the industry.

Long-term (greater than 5-year timeframe):

1. Industry should develop and implement a sustainable process to analyze and disseminate best practices for HP.

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Risk Profile #6: Loss of Situational Awareness

Statement of the Risk

As new resources are added to the system, unless information sharing takes place between distribution and BPS operators, it will become increasingly difficult to have visibility and a complete understanding of the distribution energy resource impacts. Inadequate situational awareness can be a precursor or contributor to a Bulk-Power System (BPS) events. Loss of situational awareness can occur when control rooms are not staffed properly or operators do not have sufficient information and visibility to manage the grid in real-time. Additionally, insufficient communication and data regarding neighboring entity's operations is a risk as operators may act on incomplete information.

Level of Risk

High Priority

Descriptors of the Risk

The following items can lead to inappropriate operator response or lack of action:

1. Limited real-time visibility to and beyond the immediate neighboring facilities
2. Lack of common status information on infrastructures and resources on which operators rely (gas, dispersed resources, distributed energy resources, and data and voice communications)
3. Information overload during system events
4. Inadequate tools or fully capable backup tools to address reliability
5. Lack of training on the tools and information to assess the system reliability at a given point in time
6. Incomplete data and model accuracy used to feed into real-time operations

Recommendations for Mitigating the Risk

Near-term (1–2 year timeframe):

1. Complete Standards Project 2009-02 (Real-Time Reliability Monitoring and Analysis Capabilities).
2. Research the development of measurable definitions of reserves (e.g., spinning, contingency, replacement) in light of the changing resource mix.
3. Develop real-time notification of Interconnection anomalies and outliers (large load or resource losses, large oscillations, large angle changes, low inertia).

4. Perform a root cause or common mode failure analysis of partial and full loss of key energy management system (EMS) capability using events analysis information and provide lessons-learned and recommendations to reduce the likelihood of failure.
5. Work with the forums on an approach for ongoing identification, cataloging, and sharing of good practices related to operating tools.
6. NERC should develop a guideline on situational awareness for the industry to address data modeling and information sharing.

Mid-term (3–5 year timeframe):

1. Develop and implement a set of real-time indicators of Interconnection health.
2. Engage the Electric Power Research Institute (EPRI) to develop a list of key tasks and learning objectives for wide-area monitoring as well as assessing status following system events.
3. Engage EPRI to develop a supplement or companion to the Interconnected Power System Dynamics Tutorial that deals with wide-area monitoring under a changing resource mix based on near term deliverables above.

Long-term (Greater than 5-year timeframe):

1. Engage EPRI and North American Synchrophasor Initiative (NASPI) to develop a suite of supplemental and backup tools that use synchrophasor data in lieu of Supervisory Control And Data Acquisition (SCADA).
2. Establish a forum with vendors to leverage the near-term and mid-term suggestions for improvement.

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Risk Profile #7: Extreme Natural Events

Statement of the Risk

Severe weather or other natural events (e.g., hurricanes, tornadoes, protracted extreme temperatures, geomagnetic disturbances, floods, earthquakes, etc.) are one of the leading causes of outages. Severe weather can cause Bulk-Power System (BPS) equipment damage, fuel limitations, and disruptions of voice and data communications, which, in turn, can cause loss of load for an extended period.

Level of Risk

Moderate Priority

Descriptors of the Risk

1. Extreme natural events can damage equipment and limit fuel supplies, which may lead to localized loss of load.
2. Unmitigated geomagnetic disturbances (GMD) could lead to widespread loss of load due to voltage instability in certain regions.
3. Widespread damage to certain types of BPS infrastructure can extend outages due to unavailability of nearby replacement equipment or specialized capabilities.
4. Physical damage to generation fuel sources, such as natural gas pipelines or storage facilities can degrade reliable operations of the BPS.
5. Damage to voice and data communications, as well as water supplies can make certain critical facilities vulnerable and reduce the ability to serve load.
6. The industry does not have full knowledge or coordination in accessing the existing spare equipment inventory.

Recommendations for Mitigating the Risk

Near-term (1–2 year timeframe):

1. Complete the implementation of NERC's GMD Reliability Standards across industry.
2. Expand communications among information sharing analysis centers (ISACs), including the Telecommunications and Natural Gas ISACs.
3. Study multiple simultaneous limitations on natural gas deliveries during extreme weather.
4. Participate in exercises that incorporate extreme physical events and implement recommendations from exercise or drills such as GridEx.

5. Incorporate new Electricity ISAC (E-ISAC) and Electricity Subsector Coordinating Council (ESCC) communications protocols into industry disaster preparedness processes.
6. NERC should encourage the industry, trades, and forums to evaluate inventories of critical spare transmission equipment and increase as required.
7. NERC should work with the Department of Energy, the industry, trades, and forums to identify appropriate mitigations to spare equipment gaps and transportation logistics.
8. NERC and the industry should leverage best practices and sharing of lessons learned to expand coordination during extreme weather events among Reliability Coordinators, Balancing Authorities, and Transmission Operators.

Mid-term (3–5 year timeframe):

1. Identify and promote specific resiliency best practices to plan for extreme events.
2. NERC's Operating Committee should develop a guideline outlining event response protocols and recovery strategy elements for extreme physical events, building on NERC's Emergency Planning and Operations Reliability Standards: EOP-005 and EOP-006.
3. NERC should conduct more detailed special assessment integrating:
    a. Natural gas availability, pipeline capacity, and storage facility impacts on reliability under severe scenarios
    b. Other interdependencies, such as long-haul communications and water supply
    c. Multiple regional scenarios on limitations of natural gas deliveries during extreme weather
    d. Analytic data trend insights regarding resiliency under severe weather conditions, identifying preventable aspects for BPS reliability
    e. A leveraging of the Severity Risk Index (SRI), on a more granular regional level, to measure system resilience and restoration performance for loss of generation, transmission, and load. These efforts should consider or develop new comparative and descriptive metrics.
4. NERC should perform trend analysis on historical impacts on the BPS of extreme natural events.

Long-term (greater than 5-year timeframe):

1. Analyze data from GMD events to further the understanding of geomagnetic induced currents (GIC effects) on Bulk Electric System facilities.
2. Institutionalize relationships among ESCC, government, and industry partners, to enhance the culture of recognizing and addressing extreme physical event preparedness across industry.
3. Develop a plan to review and improve trend of SRI as indicative measure of system resilience and restoration performance for loss of generation, transmission, and load.
4. Facilitate planning considerations to simulate extreme natural events.

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Risk Profile #8: Physical Security Vulnerabilities

Statement of the Risk

Intentional damage, destruction, or disruption to facilities can cause localized to extensive Interconnection-wide Bulk-Power System (BPS) disruption potentially for an extended period.

Level of Risk

Moderate Priority

Descriptors of the Risk

1. Increasing and evolving threat around physical attacks.
2. The exposed nature of the grid, which is vulnerable and difficult to protect.
3. Long lead times associated with manufacturing and replacing some equipment, which can increase complexity of restoration after physical attacks that damages BPS equipment.
4. The level of industry knowledge or coordination in accessing the existing spare equipment inventory.
5. Physical damage to generation fuel sources, such as natural gas pipelines, which will degrade reliable operations of the BPS.
6. Damage to long-haul telecommunications and water supplies, which will make certain critical facilities vulnerable and reduce the ability to serve load.
7. An electromagnetic pulse (EMP) event, which could lead to widespread loss of load in certain regions.

Recommendations for Mitigating the Risk

Near-term (1–2 year timeframe):

1. NERC should continue to oversee the implementation of NERC's Physical Security Reliability Standard entitled Critical Infrastructure Protection (CIP-014-1).
2. Enhance the coordination between Electricity Information Sharing and Analysis Center (E-ISAC) and the Telecommunications and Water supply ISACs.
3. NERC should develop effective metrics formulated to understand the trend of physical attacks and potential threats
4. Assess the risks of physical attack scenarios on midstream or interstate natural gas pipelines on natural gas availability impacting generation and the reliability of the BPS in the NERC's long-term reliability assessments and planning activities.

5. NERC should promote industry efforts with the trades and forums to develop a spare equipment strategy and prioritization.
6. NERC should expand GridEx to include more facilities and industries.
7. The forums and trades should perform the following activities:
    a. Identify and promote specific resiliency and vulnerability assessment best practices with planning for extreme events, including good physical security assessment practices.
    b. Develop an event guideline outlining prevention strategies and event response and recovery protocols for sabotage scenarios.

Mid-term (3–5 year timeframe):

1. Develop a catalog of regional/national exercises that incorporate extreme physical events and share with industry, supporting increased participation across industry.
2. The industry should review and update restoration plans reflecting consideration of physical security scenarios.
3. Develop performance and metrics reporting on joint E-ISAC and Telecommunications ISAC assessments of potential physical attack disruptions, differentiating from vandalism or theft incidents.
4. Conduct a special regional assessment that addresses natural gas availability and pipeline impacts under physical attack scenarios.
5. NERC should work with the US Department of Energy as well as Canadian and Mexican authorities, the industry, trades, and forums to identify appropriate mitigations to spare equipment gaps and transportation logistics.
6. NERC, the industry, trades, and forums should evaluate inventories of critical spare transmission equipment and increase as required.
7. The industry should evaluate mechanisms for cost recovery of implementing specific resiliency strategies by the industry.
8. Industry should work with the technical committees and forums to develop mitigation strategies and physical security assessment best practices.
9. Expand participation in security exercises, in addition to GridEx, that reflect extreme physical events.
10. Facilitate planning considerations that seeks to lower risk profiles and vulnerabilities.

Long-term (greater than 5-year timeframe):

1. Relationships among the Electricity Subsector Coordinating Council (ESCC), government, and industry partners should be institutionalized, in part to enhance a culture of recognizing and addressing extreme physical event preparedness across industry.

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Risk Profile #9: Cyber Security Vulnerabilities

Statement of the Risk

Exploitation of cyber security vulnerabilities can potentially result in loss of control or damage to Bulk-Power System (BPS) related voice communications, data, monitoring, protection and control systems, or tools. Successful exploitation can damage equipment causing loss of situational awareness and, in extreme cases, can result in degradation of reliable operations to the BPS, including loss of load.

Level of Risk

High Priority

Descriptors of the Risk

1. Cyber security threats result from both external and internal vulnerabilities:
   a. Exploitation of employee and insider access
   b. Weak security practices of host utilities, third-party vendors, and other organizations
   c. Growing sophistication of bad actors, nation states, and collaboration between these groups
2. Interdependencies from the Department of Homeland Security Critical Infrastructure Sectors[1] (Communications, Financial Services, Oil and Natural Gas Subsector, and Water) with their own cyber vulnerabilities can impact the BPS reliability.
3. Legacy architecture coupled with the increased connectivity of the grid expands the attack surface of BPS protection and control systems:
   a. Increased automation of the BPS through control systems implementation
   b. Business needs accelerating the convergence of information technology (IT)/operating technology (OT)
   c. IT/OT infrastructure management, out-of-date operating systems, and the lack of patching capability/discipline
4. Ineffective teamwork and collaboration among the federal, provincial, state, local government, private sector and critical infrastructure owners can exacerbate cyber events.
5. Lack of staff that is knowledgeable and experienced in cybersecurity, control systems, and the IT/OT networks supporting them (historically separate organizations and skillsets), symptomatic across all industries hinders an organization's ability to detect and prevent cyber incidents.

[1] https://www.dhs.gov/critical-infrastructure-sectors

Recommendations for Mitigating the Risk

Near-term (1–2 year timeframe):

1. Address FERC critical infrastructure protection (CIP) directives in *Revised Critical Infrastructure Protection Reliability Standards*, 154 FERC ¶ 61,037 (2016).
2. NERC and the Critical Infrastructure Protection Committee (CIPC) should develop an ongoing cyber vulnerability risk guidance process to inform and educate the industry.
3. NERC should continue information sharing protocols among interdependent information sharing analysis centers (ISACs).
4. The Electricity ISAC (E-ISAC) should continue outreach to industry to increase registration and utilization of E-ISAC portal.
5. The E-ISAC should mature the cybersecurity risk information sharing program (CRISP) and encourage expanded participation.
6. NERC and the CIPC should prioritize lessons learned from regional and national exercises (e.g., GridEx) and publish lessons learned and guidelines as needed.
7. The industry should encourage the development of a peer review process for emerging risks.
8. The industry should create and foster an internal culture of cyber awareness and safety.

Mid-term (3–5 year timeframe):

1. NERC should develop feedback mechanism from CIP standards implementation to evaluate the standard and lessons learned from technology deployment.
2. The Electricity Sub-sector Coordinating Council (ESCC) should operationalize the cyber mutual assistance framework to address issues with recovery after a cyber-attack.
    a. Cross industry sharing of best practice incident response plans
    b. Creation and/or expansion of security operations center(s) that incorporate the BPS (IT/OT convergence areas)
3. NERC should mature the existing metrics to determine the trend of cyber and threat actors.
4. Develop an effective plan to ensure joint coordination of industry efforts on potential all supply chain disruptions.

Long-term (greater than 5-year timeframe):

1. Foster the development of methods, models, and tools to simulate system reliability impacts for the planning and operational planning time horizons.
2. Develop operating industry guidelines incorporating resilience.
3. Create and document pathways for technology integration, while maintaining or enhancing resilience.

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Transformer Thermal Impact Assessment White Paper

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 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.

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.

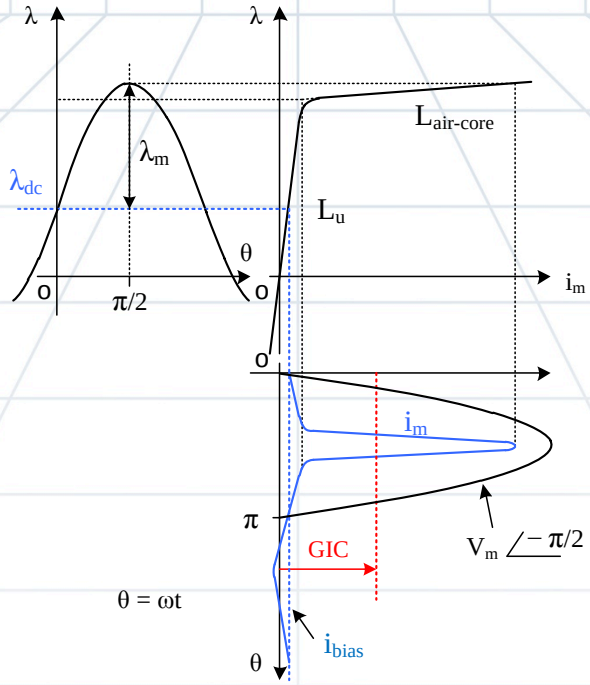


Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

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] for hot spot heating during short-term emergency operation. 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 "waveshape" 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 2 from the "Screening Criterion for Transformer Thermal Impact Assessment" white paper [7]. This table, shown as Table 1 below, provides the peak metallic hot spot temperatures that can be reached using conservative thermal models. To use Table 1, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after 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.

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

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)[1] or International Council on Large Electric Systems (CIGRE) may also provide technically justified methods for performing thermal assessments. All thermal assessment methods should be demonstrably equivalent to assessments that use the benchmark GMD event.

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 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. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC waveshape is equivalent to, for example, a 2 minute pulse. Also, manufacturers generally maintain that in

[1] For instance, IEEE Std C57.163-2015 Guide for Establishing Power Transformer Capability while under Geomagnetic Disturbances

the absence of transformer standards defining thermal duty due to GIC, such capability curves must be developed for every transformer design and vintage.

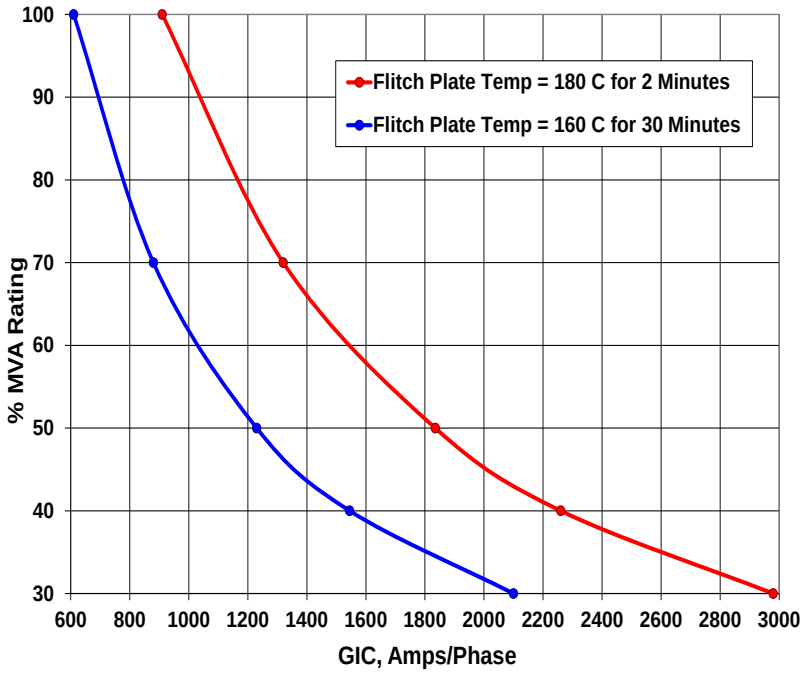


Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[2]. The input to this type of simulation is the time series or waveshape 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] 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]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[2] Technical details of this methodology can be found in [4].

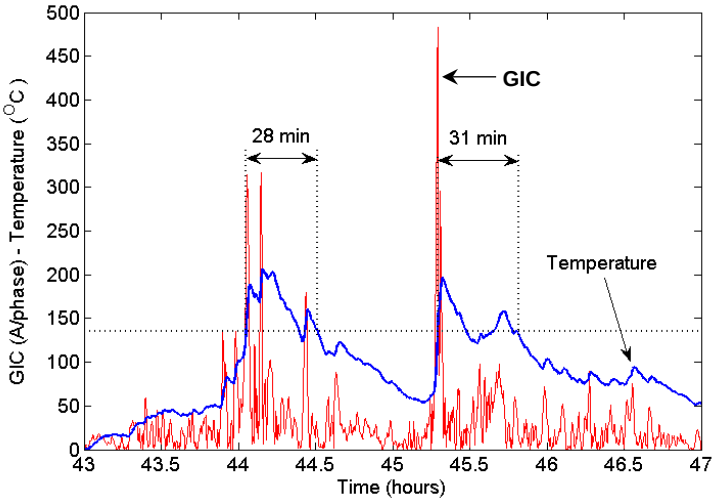


Figure 3: Sample Tie Plate Temperature Calculation
Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" 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 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/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] after the appropriate geomagnetic latitude scaling factor α is applied[3]. 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 conductivity scaling factor β[4]. 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]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)} \quad (6)$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)} \quad (7)$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

[3] 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.

[4] 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.

It should be emphasized that even for the same reference event, the GIC(t) waveshape 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 to test all transformers is incorrect.

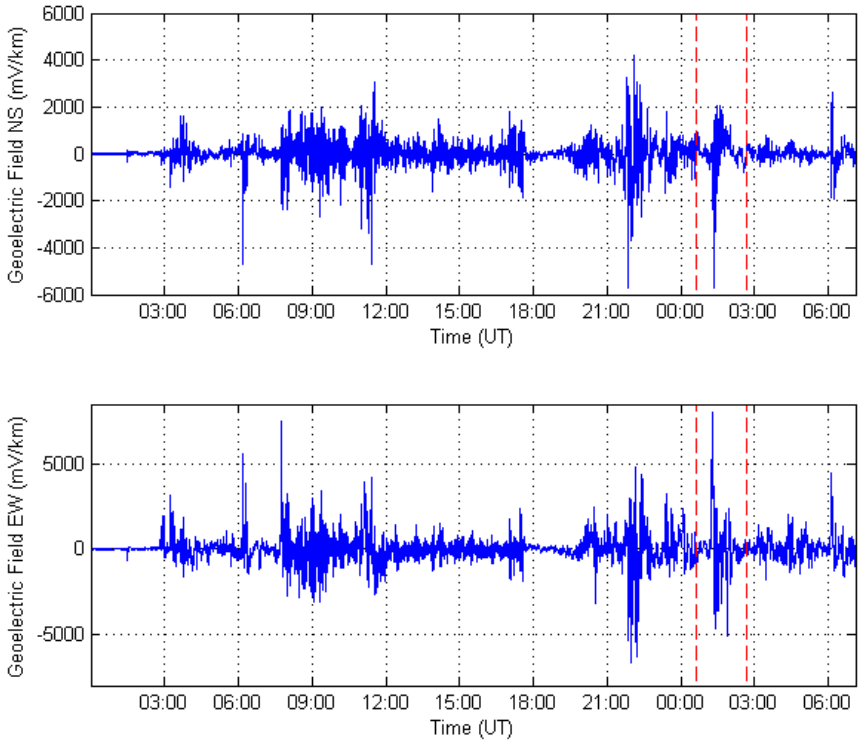


Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

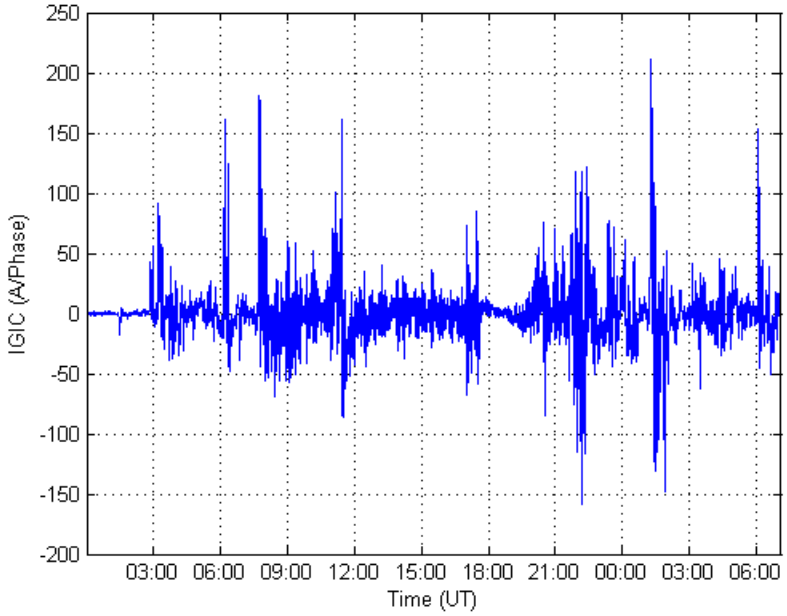


Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

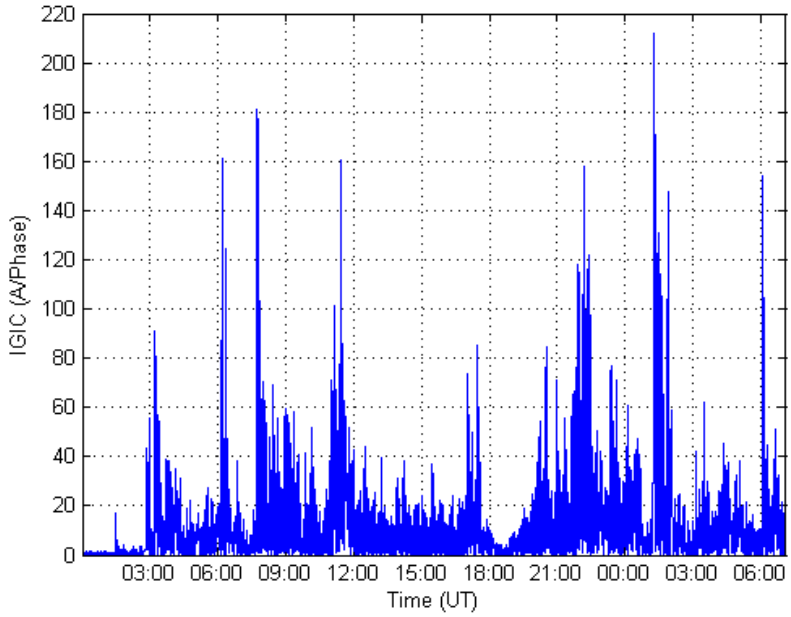


Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

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] 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.[5]

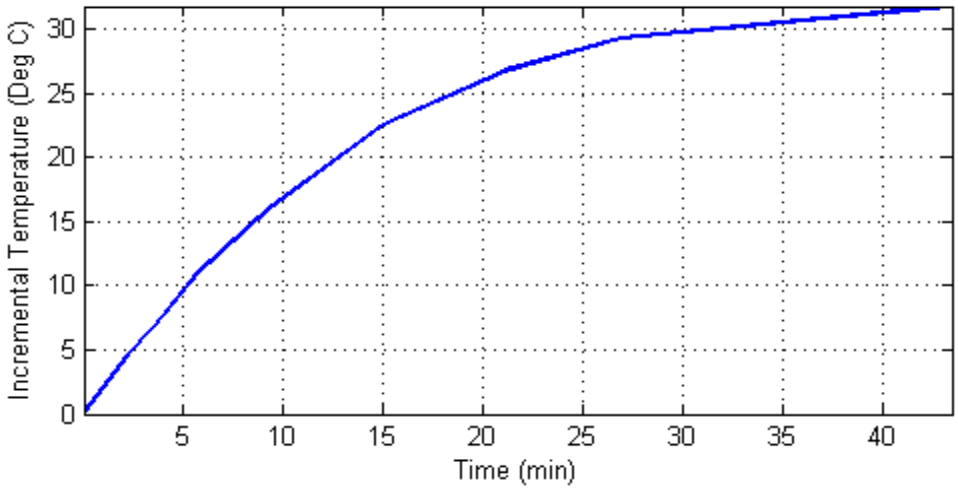


Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step
Metallic hot spot heating.

[5] 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.

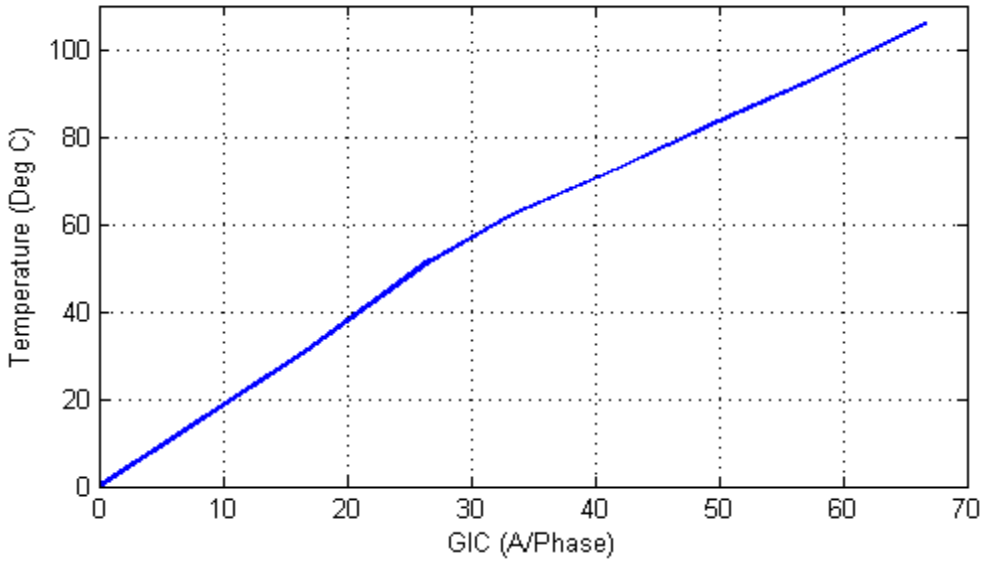


Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

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.

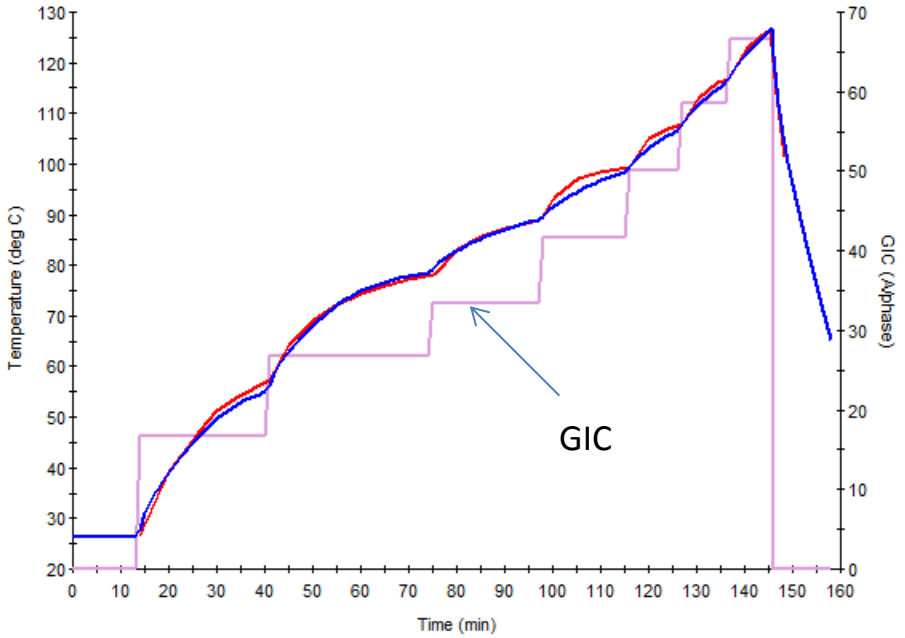


Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). Injected current is represented by the magenta trace.

To obtain the thermal response of the transformer to a GIC waveshape 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 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. 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 hot spot temperature time series $\theta(t)$. **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

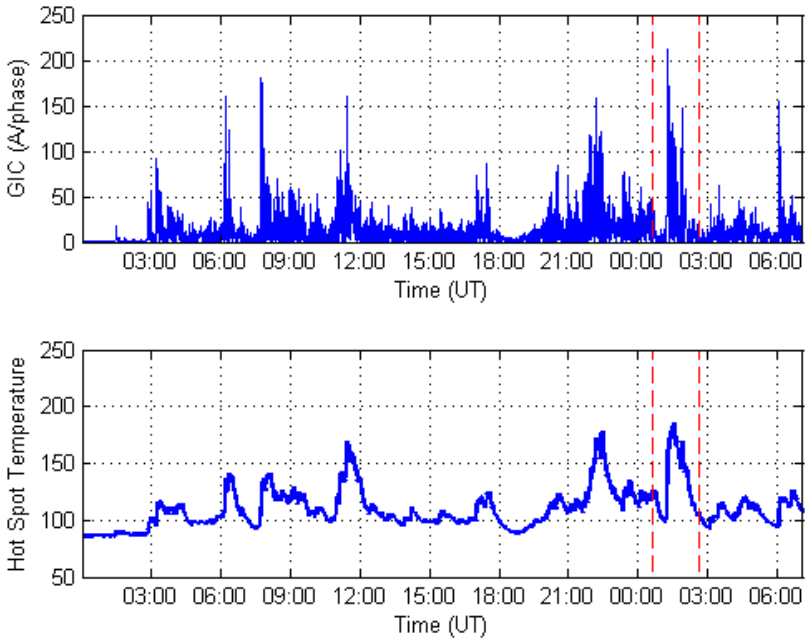


Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature $\theta(t)$ Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

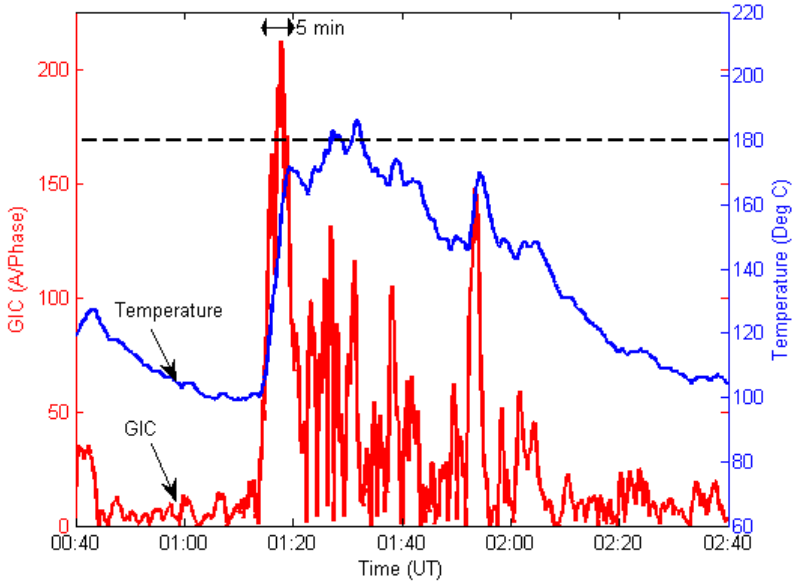


Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std C57.91 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.

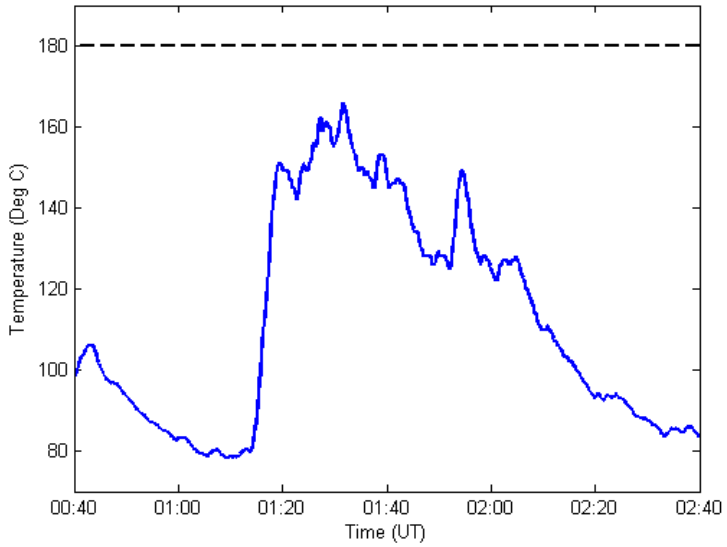


Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

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).

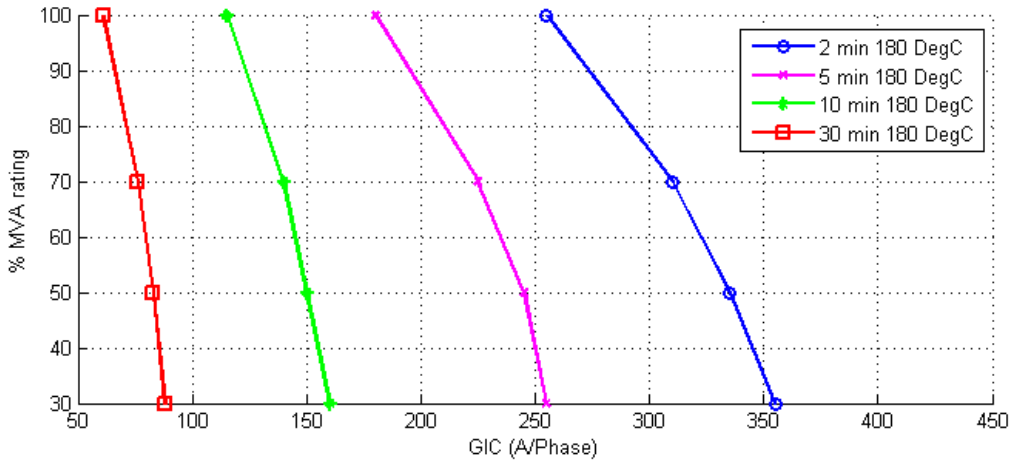


Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

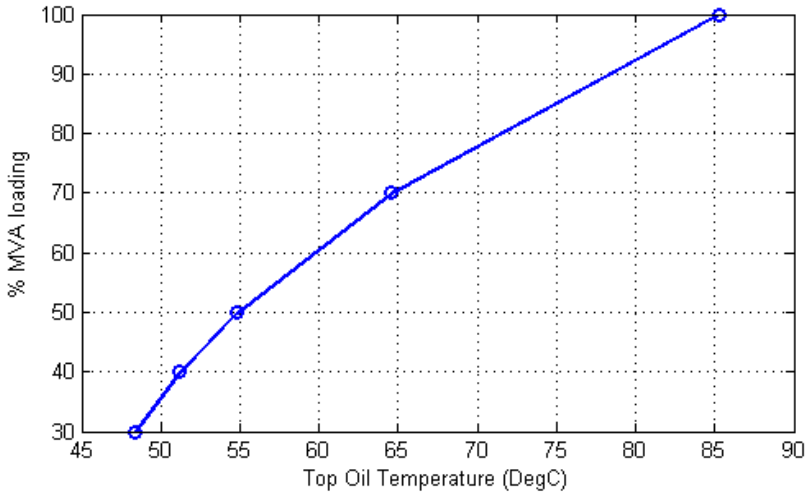


Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

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 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.

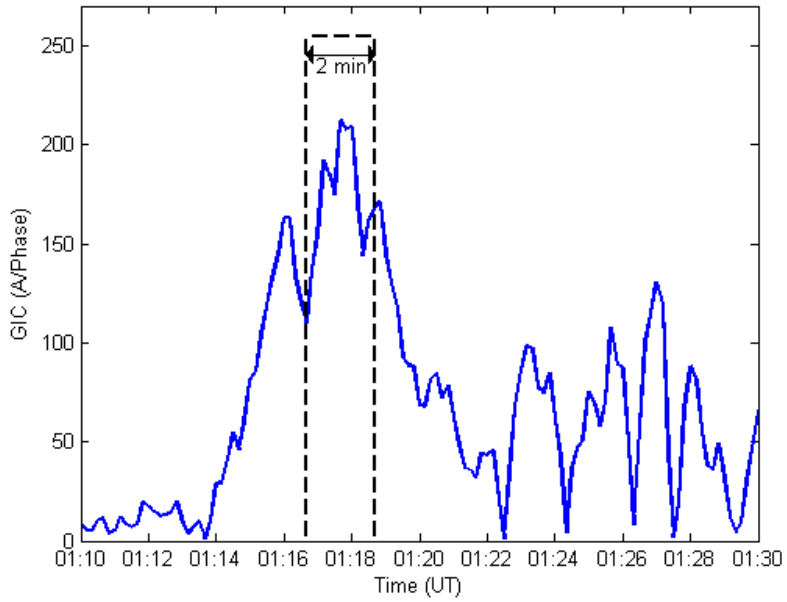


Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

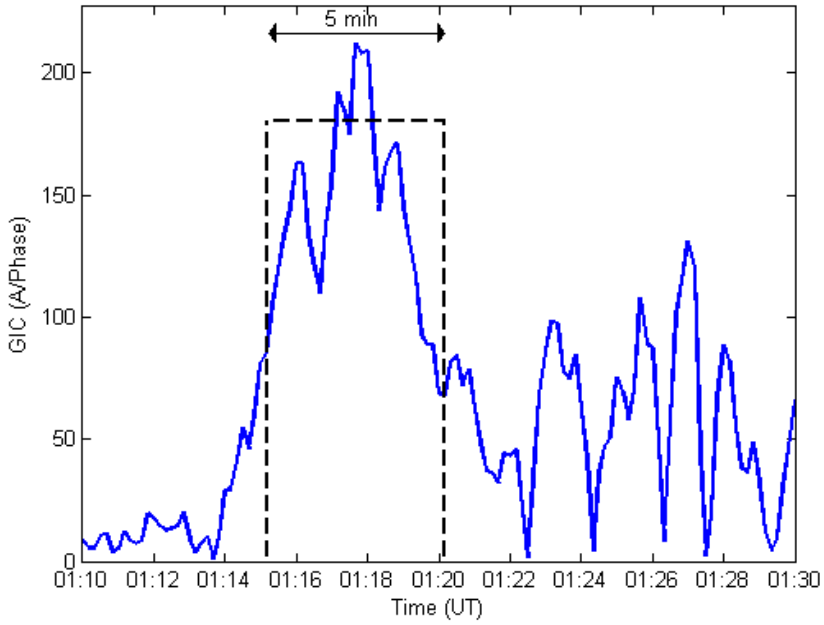


Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

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 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.

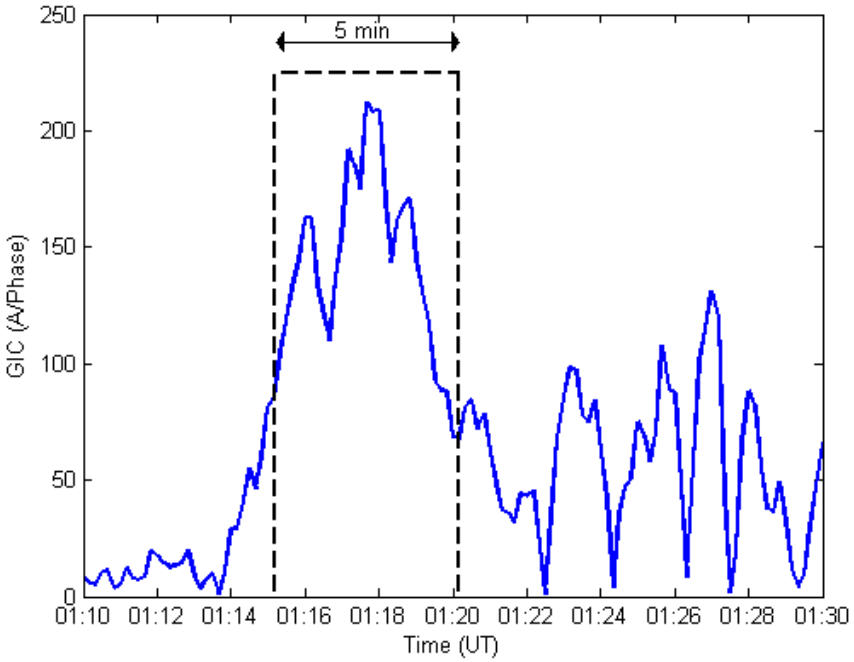


Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

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[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).

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation
Standard Drafting Team
May 12, 2016

RELIABILITY | ACCOUNTABILITY





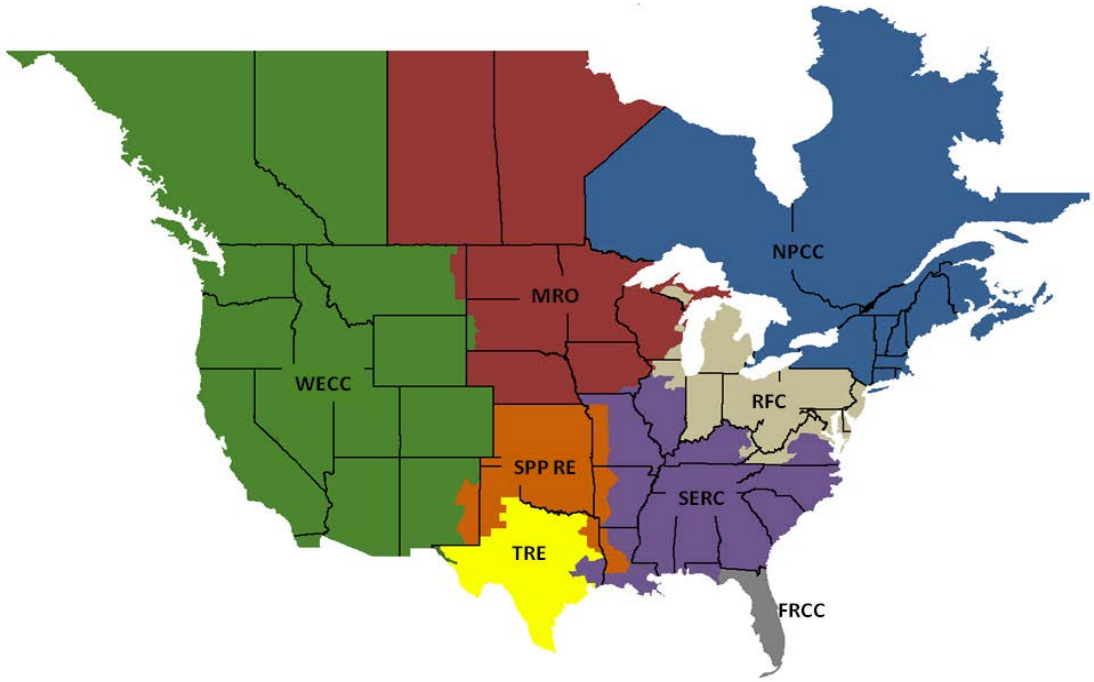

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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure 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 several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances 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 developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape 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 magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. Since geomagnetic disturbance impacts within areas of influence of approximately 100-200 km do not have a widespread impact on the interconnected transmission system (see Appendix I), statistical methods used to assess the frequency of occurrence of a severe GMD event need to consider broad geographical regions to avoid bias caused by spatially localized geomagnetic phenomena.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. The benchmark 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 waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. 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 II) resulted in a conservative peak geoelectric field amplitude of approximately 8 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 frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

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 8 V/km using the following relationship

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

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 (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the

reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is 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 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

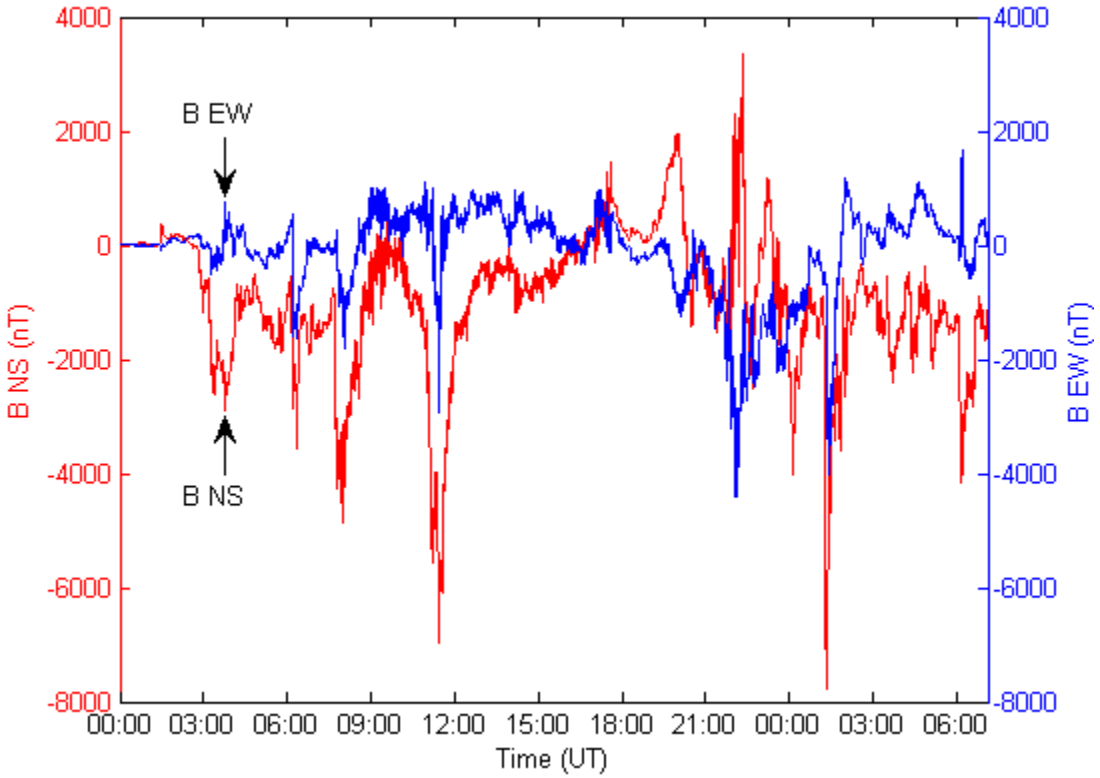


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

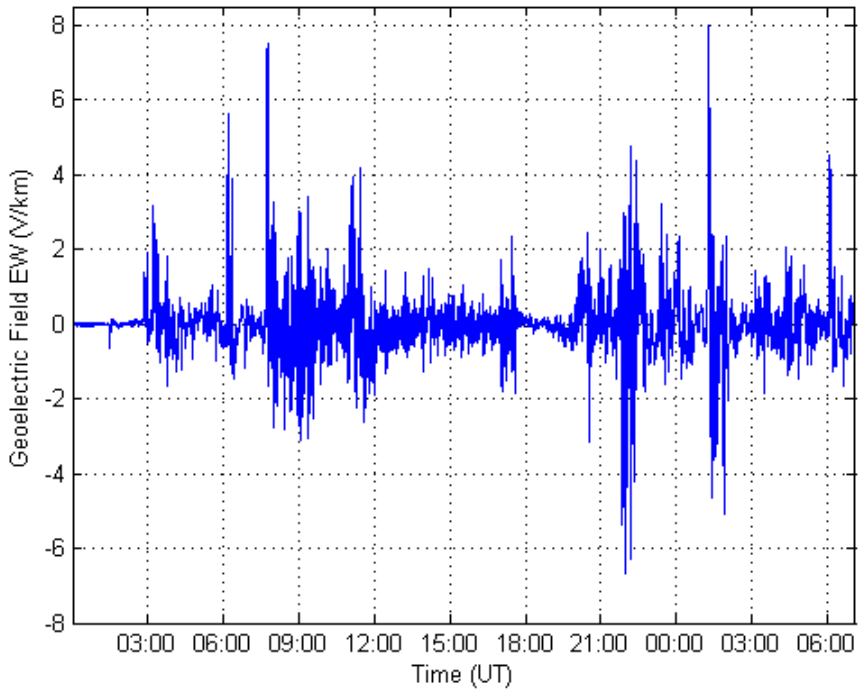


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

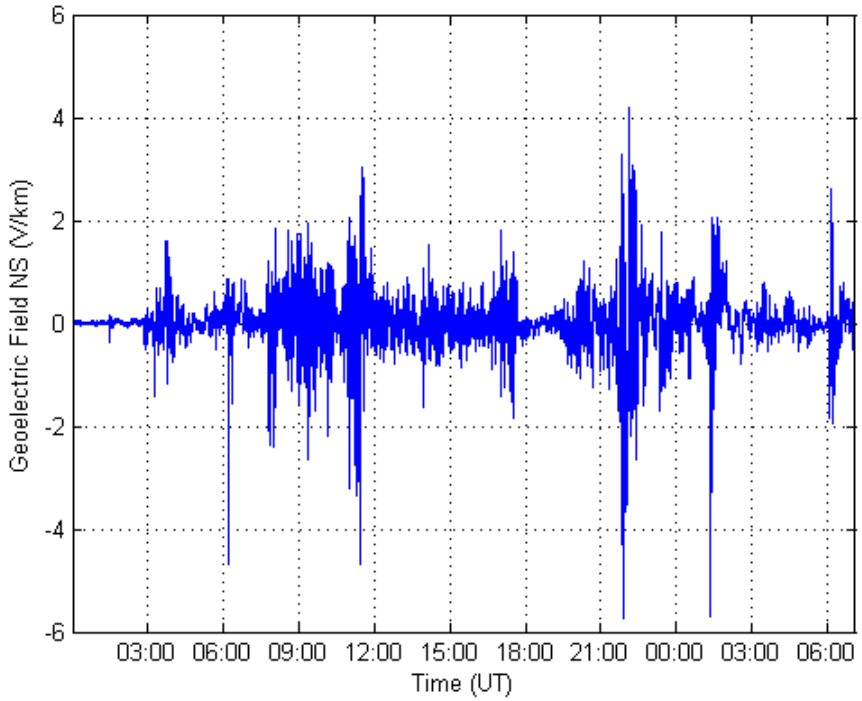


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** 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.

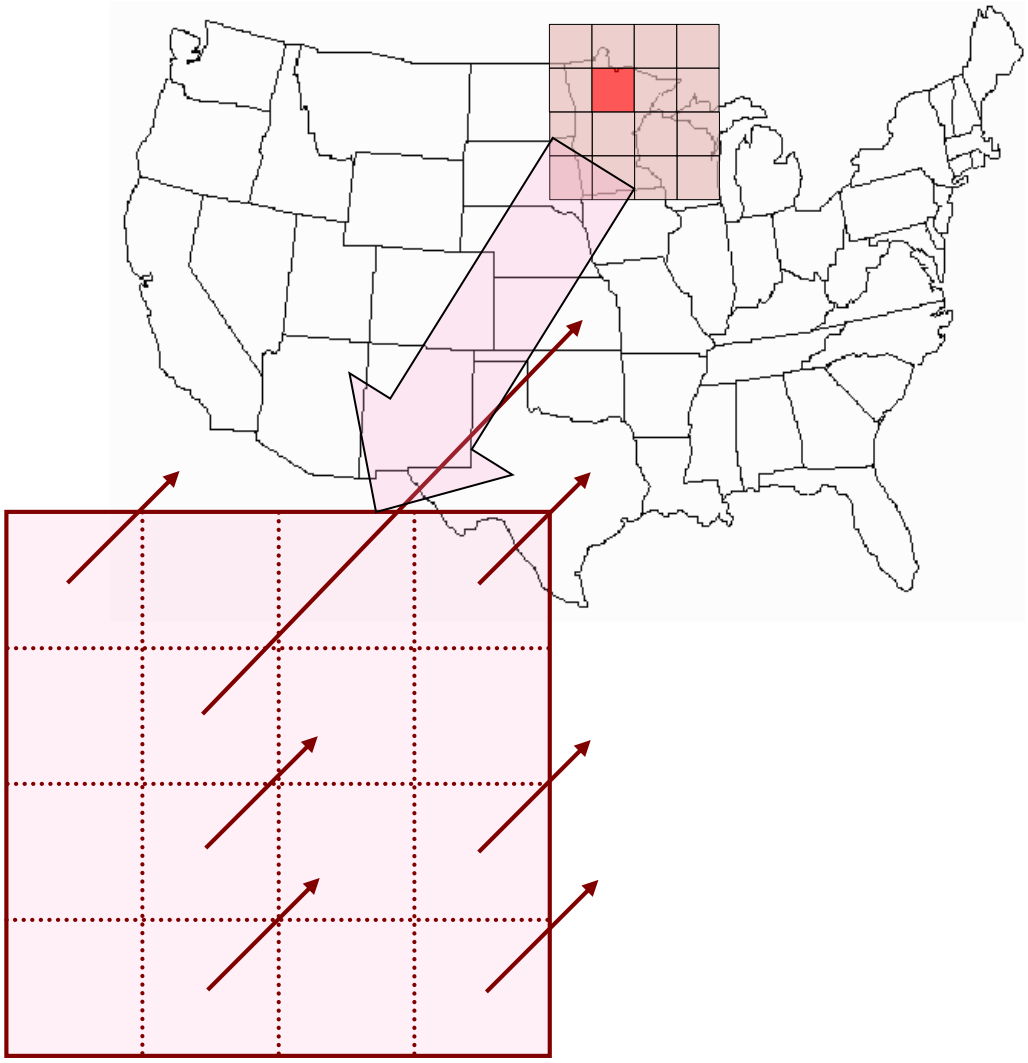


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

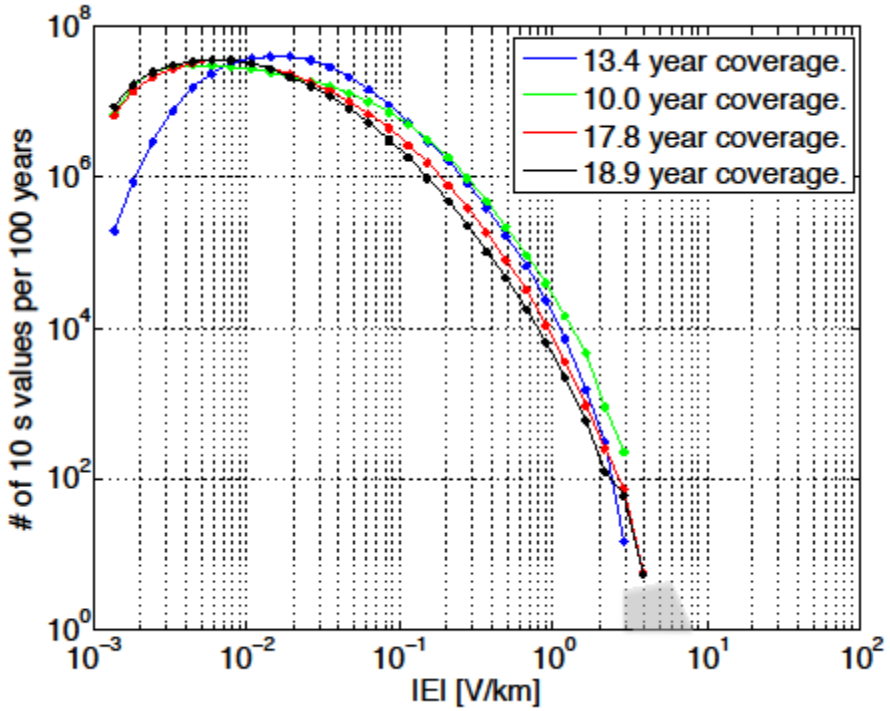


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes.
Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

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 percent confidence interval of the maximum geoelectric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

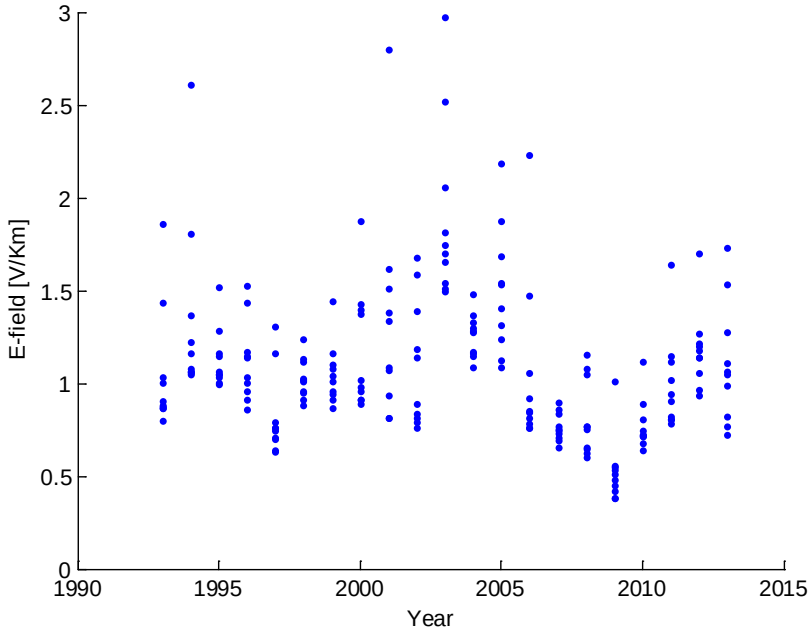


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

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 [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT 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 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] 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.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

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 Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization 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: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The benefit is an increase in the mean return

level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] 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 1 V/km; the data was de-clustered 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; a threshold that is too low will likely lead to bias. On the other hand, a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size, the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used 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 statistically significant; the null hypothesis, H0: $\alpha_1=0$, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). 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.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis is consistent with the selection of a geoelectric field amplitude of 8 V/km for the 100-year GMD benchmark. .

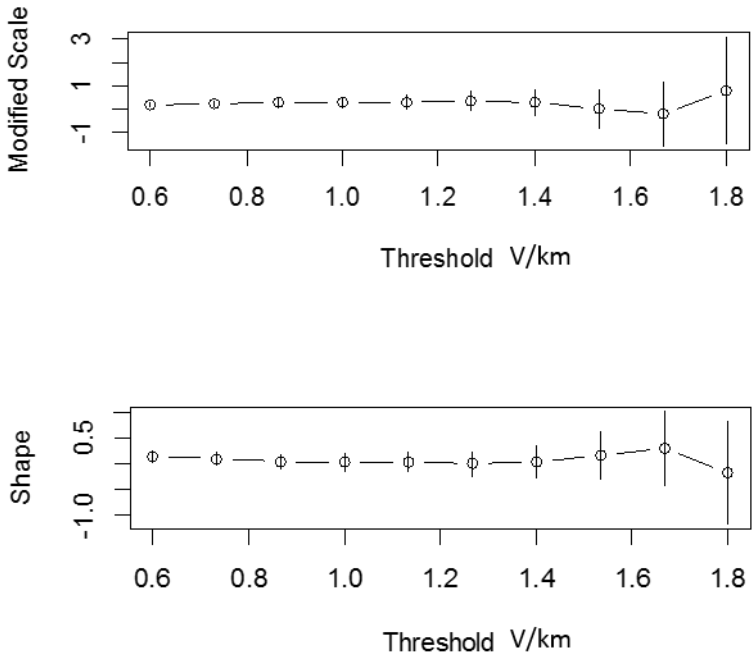


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

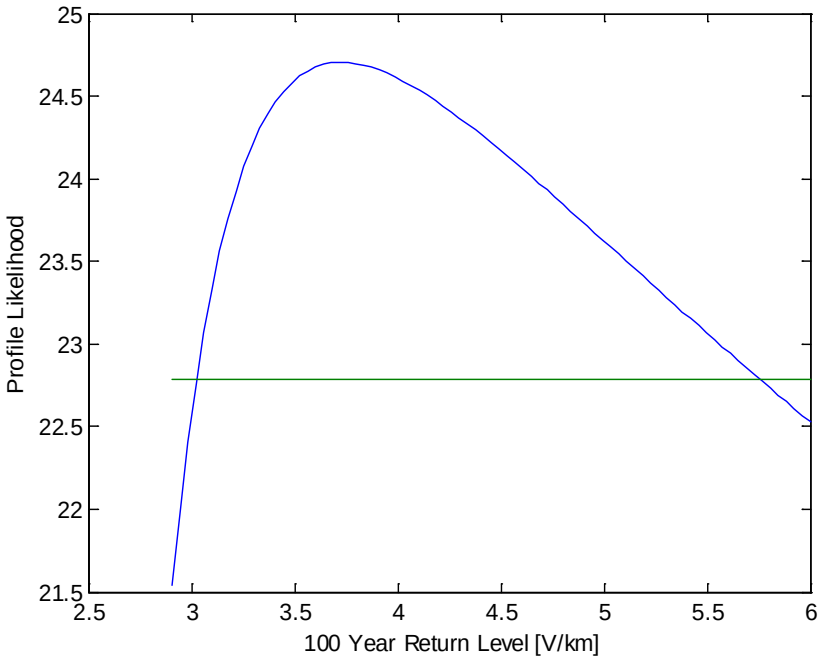


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

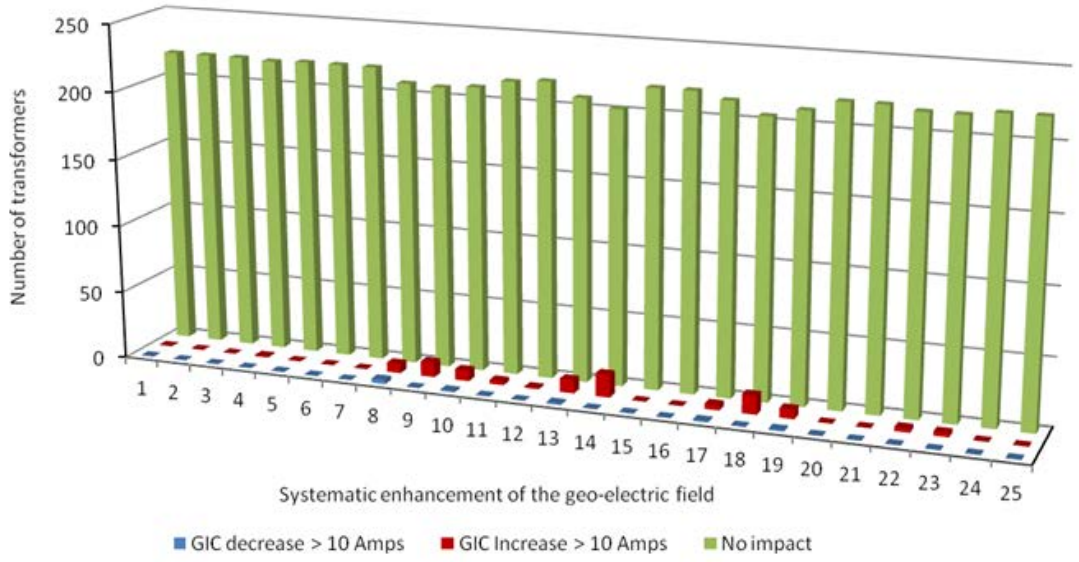


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

as the measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003 described in the NERC GMD interim report of 2012 [14].

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. **Figure I-9** shows a more systematic way to compare the relative effects of storm waveshape on the thermal response of a transformer. It shows the results of 33,000 thermal assessments for all combinations of effective GIC due to circuit orientation (similar **to Figures I-7** and **I-8** but systematically taking into account all possible circuit orientations). These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

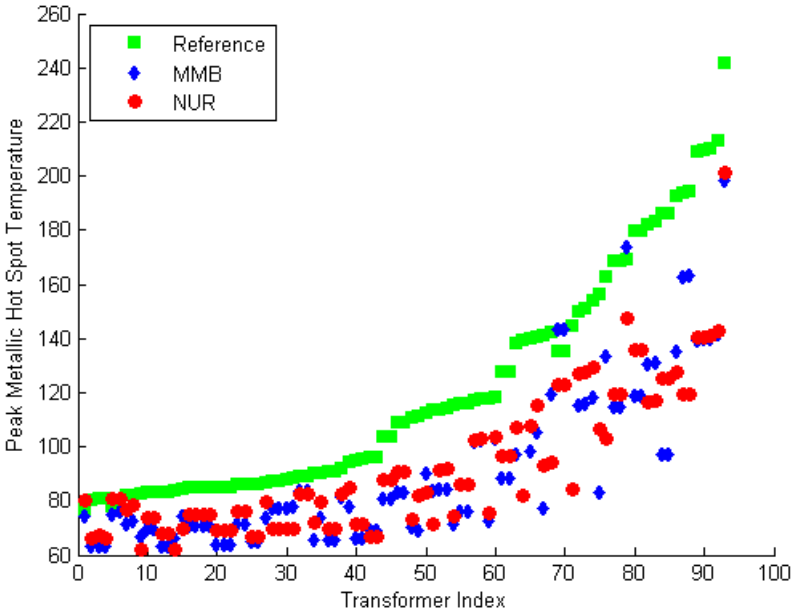


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

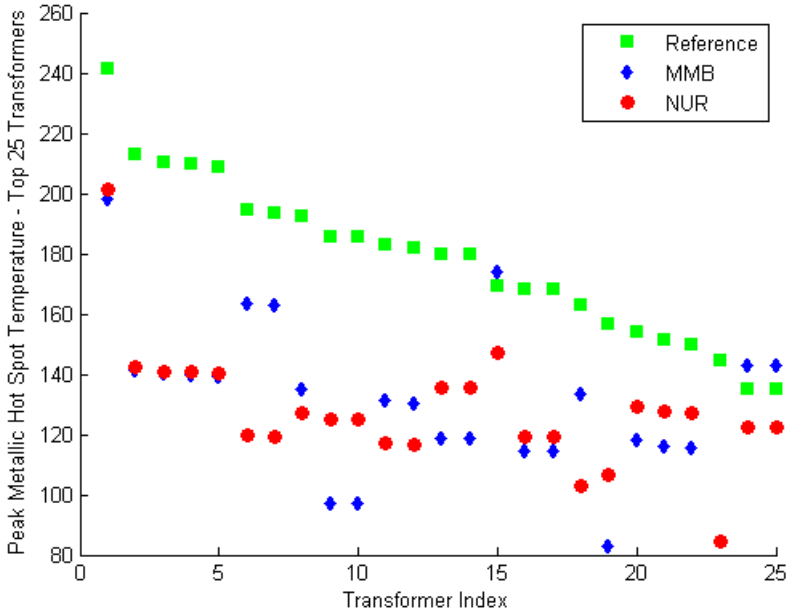


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field

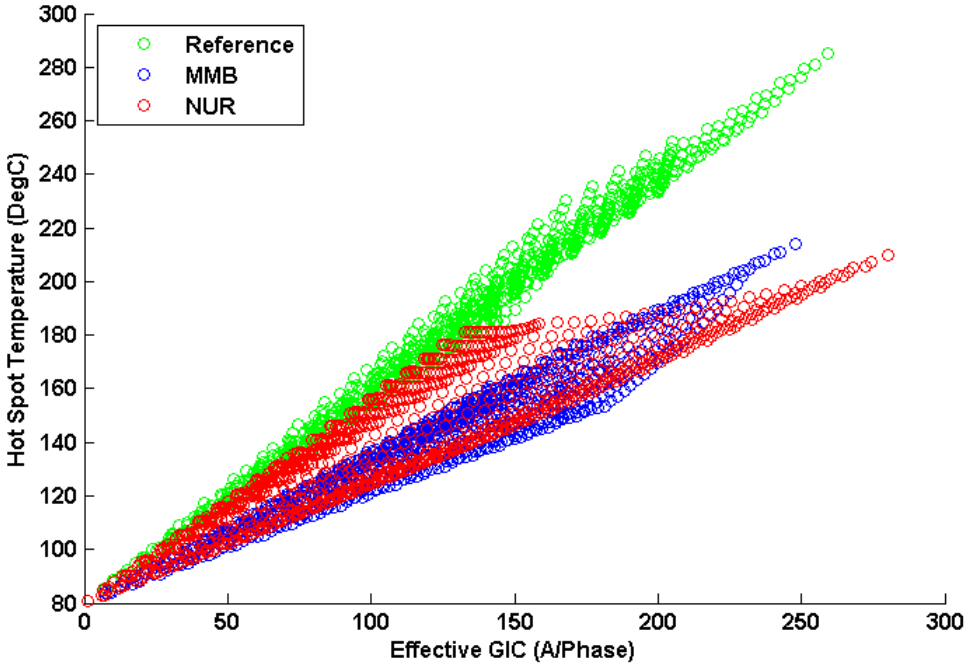


Figure I-9: Calculated Peak Metallic Hot Spot Temperature for all possible circuit orientations and effective GIC.

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]**.** 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 Geomagnetic Field

The benchmark 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 reference geomagnetic field waveshape 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], [24]-[25], 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 $0.1 \leq \alpha \leq 1.0$.

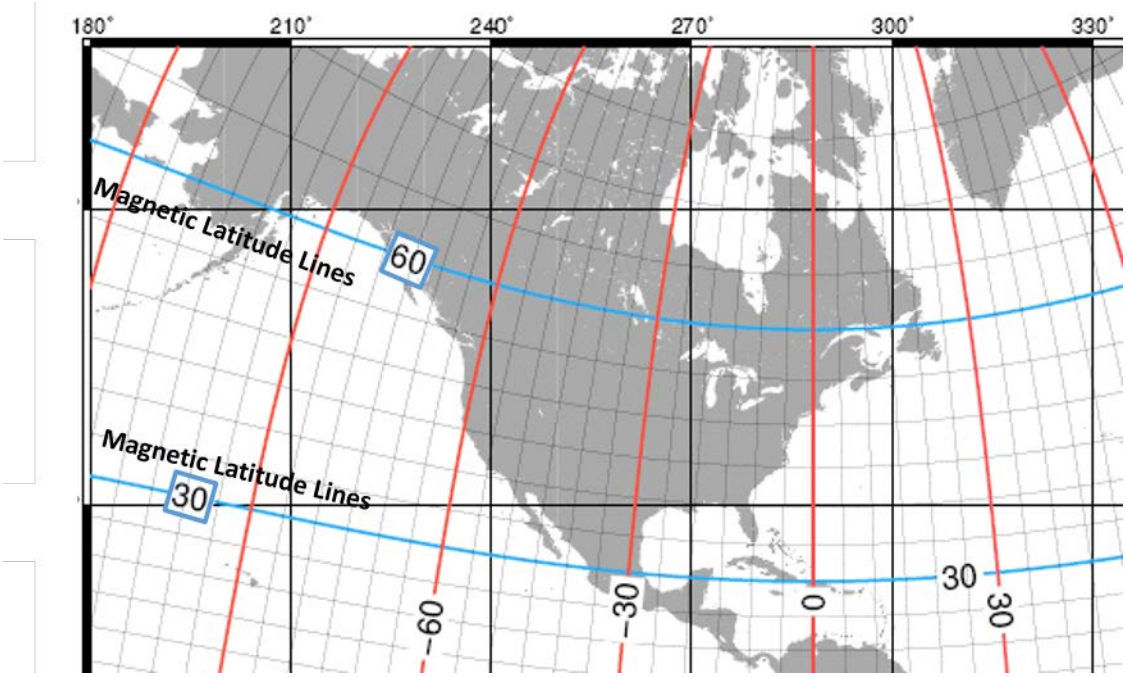


Figure II-1: Geomagnetic Latitude Lines in North America

[6] 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.

[7] 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.

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 benchmark 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 [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$E_N = (z(t)/\mu_o) * B_E(t)$$
$$E_E = -(z(t)/\mu_o) * B_N(t) \qquad \text{(II.2)}$$
$$E_{peak} = \max\left\{\left|E_E(t), E_N(t)\right|\right\}$$

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 waveshapes,

$E_E(t)$, $E_N(t)|$ 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.

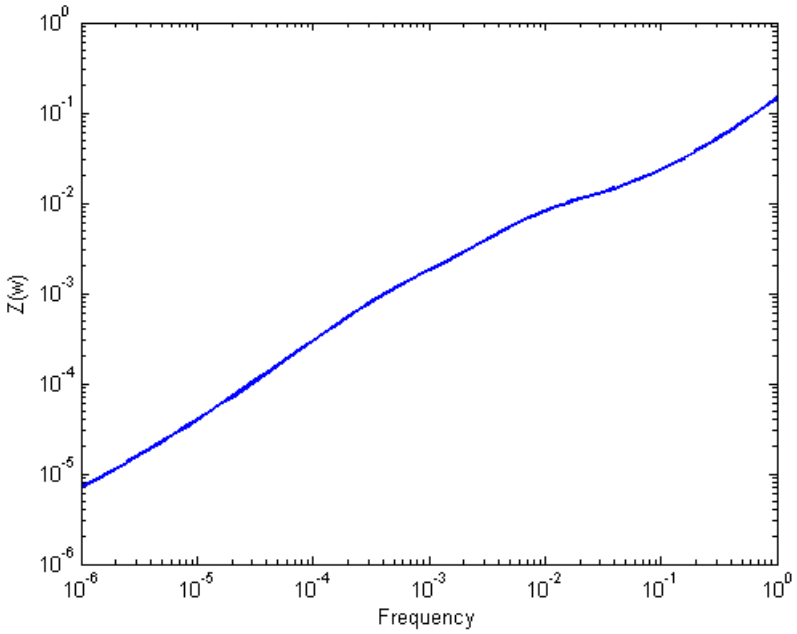


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β 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)

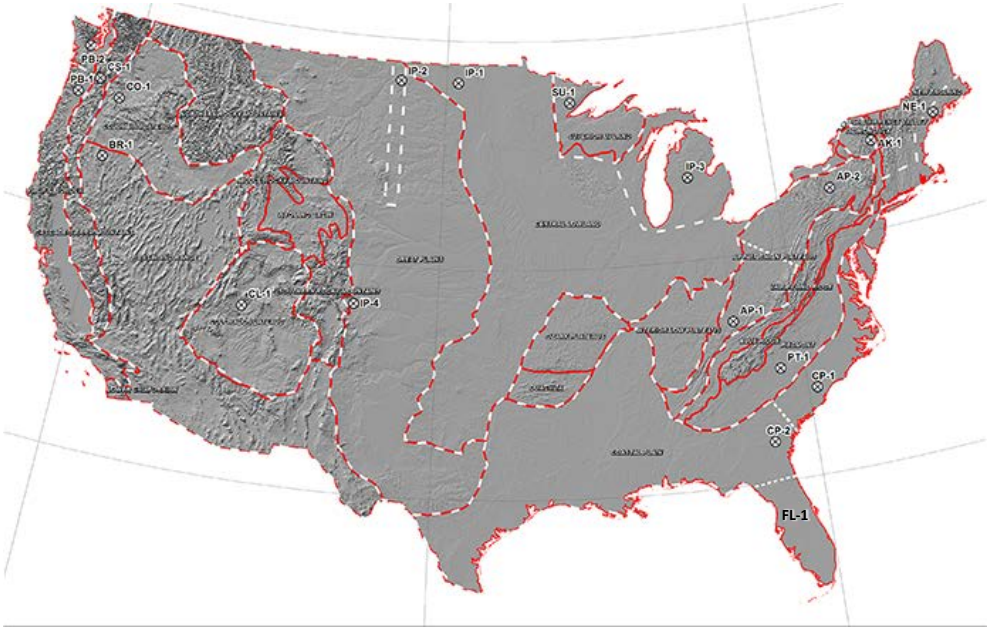
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad \text{(II.3)}$$

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.
- 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 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 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference 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. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second recordings for these geomagnetic field time series.
- 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 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 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

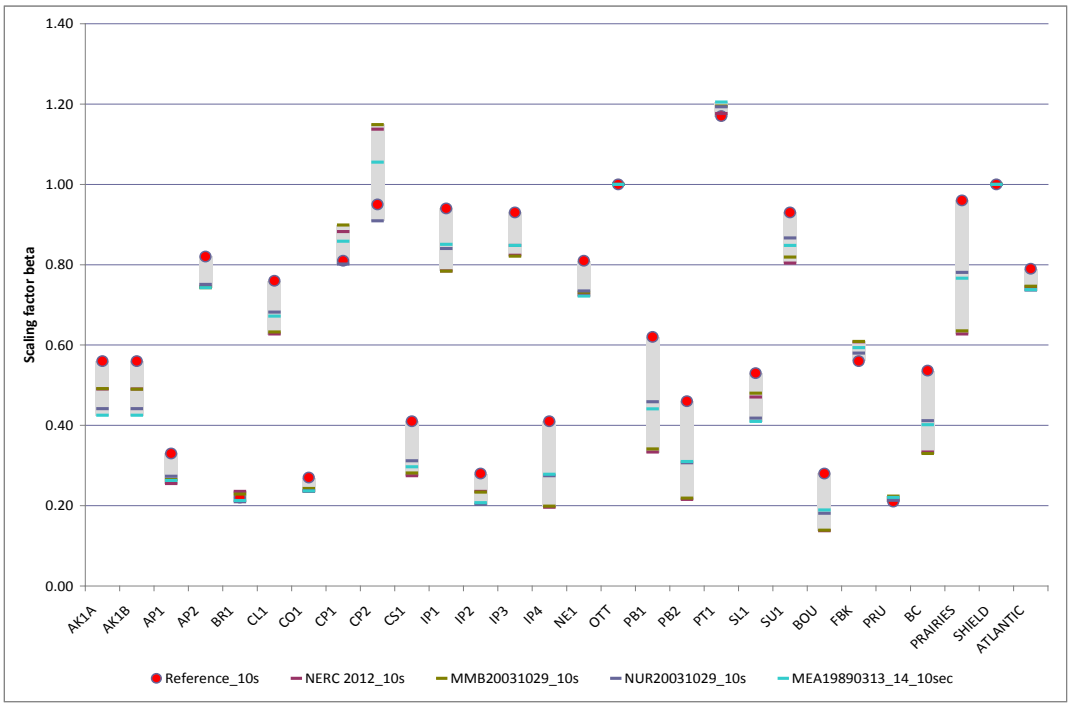


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles correspond to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5 V/km$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity than the reference benchmark conductivity, therefore, according to the conductivity factor β from Table II-2., the calculation follows:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2V / km$$

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Screening Criterion for Transformer Thermal Impact Assessment

Project 2013-03 (Geomagnetic Disturbance Mitigation)

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

Summary

Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. The standard requires transformer thermal impact assessments to be performed on power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. Transformers are exempt from the thermal impact assessment requirement if the maximum effective geomagnetically-induced current (GIC) in the transformer is less than 75 A per phase as determined by GIC analysis of the system. Based on published power transformer measurement data as described below, an effective GIC of 75 A per phase is a conservative screening criterion. To provide an added measure of conservatism, the 75 A per phase threshold, although derived from measurements in single-phase units, is applicable to transformers with all core types (e.g., three-limb, three-phase).

Justification

Applicable entities are required to carry out a thermal assessment with GIC(t) calculated using the benchmark GMD event geomagnetic field time series or waveshape for effective GIC values above a screening threshold. The calculated GIC(t) for every transformer will be different because the length and orientation of transmission circuits connected to each transformer will be different even if the geoelectric field is assumed to be uniform. However, for a given thermal model and maximum effective GIC there are upper and lower bounds for the peak hot spot temperatures. These are shown in **Figure 1** using three available thermal models based on direct temperature measurements.

The results shown in **Figure 1** summarize the peak metallic hot spot temperatures when GIC(t) is calculated using (1), and systematically varying GIC_E and GIC_N to account for all possible orientation of circuits connected to a transformer. The transformer GIC (in A/phase) for any value of E_E (t) and E_N(t) can be calculated using equation (1) from reference [1].

$$GIC(t) = \left|E(t)\right| \cdot \left\{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\right\} \quad (1)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \tag{2}$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \tag{3}$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \tag{4}$$

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/V/km.

It should be emphasized that with the thermal models used and the benchmark GMD event geomagnetic field waveshape, peak hot spot temperatures must lie below the envelope shown in **Figure 1**. The x-axis in Figure 1 corresponds to the absolute value of peak GIC(t). Effective maximum GIC for a transformer corresponds to a worst-case geoelectric field orientation, which is network-specific. Figure 1 represents a possible range, not the specific thermal response for a given effective GIC and orientation.

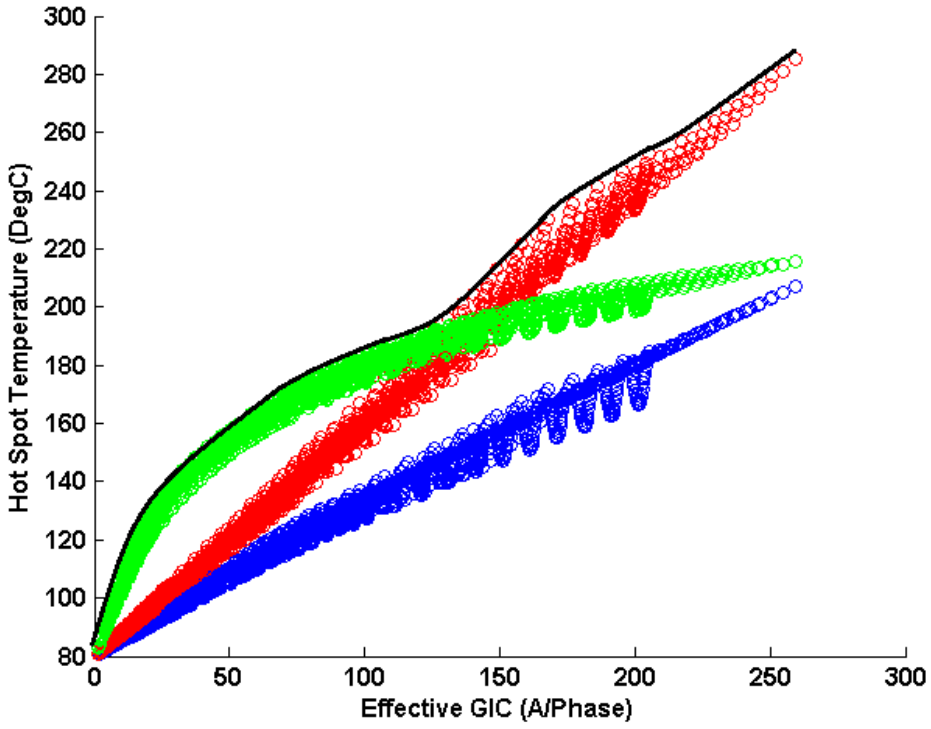


Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: SVC coupling transformer model [2]. Blue: Fingrid model [3]. Green: Autotransformer model [4].

Consequently, with the most conservative thermal models known at this point in time, the peak metallic hot spot temperature obtained with the benchmark GMD event waveshape assuming an effective GIC magnitude of 75 A per phase will result in a peak temperature between 160°C and 172°C when the bulk oil temperature is 80°C (full load bulk oil temperature). The upper boundary of 172°C remains well below the metallic hot spot 200°C threshold for short-time emergency loading suggested in IEEE Std C57.91-2011 [5] (see Table 1).

TABLE 1:
Excerpt from Maximum Temperature Limits Suggested in IEEE C57.91-2011

	Normal life expectancy loading	Planned loading beyond nameplate rating	Long-time emergency loading	Short-time emergency loading
Insulated conductor hottest-spot temperature °C	120	130	140	180
Other metallic hot-spot temperature (in contact and not in contact with insulation), °C	140	150	160	200
Top-oil temperature °C	105	110	110	110

The selection of the 75 A per phase screening threshold is based on the following considerations:

- A thermal assessment using the most conservative thermal models known to date will not result in peak hot spot temperatures above 172°C. Transformer thermal assessments should not be required by Reliability Standards when results will fall well below IEEE Std C57.91-2011 limits.
- Applicable entities may choose to carry out a thermal assessment when the effective GIC is below 75 A per phase to take into account the age or condition of specific transformers where IEEE Std C57.91- 2011 limits could be assumed to be lower than 200°C.
- The models used to determine the 75 A per phase screening threshold are known to be conservative at higher values of effective GIC, especially the SVC coupling transformer model in [2].
- Thermal models in peer-reviewed technical literature, especially those calculated models without experimental validation, are less conservative than the models used to determine the screening threshold. Therefore, a technically-justified thermal assessment for effective GIC below 75 A per phase using the benchmark GMD event geomagnetic field waveshape will always result in a "pass" on the basis of the state of the knowledge at this point in time.
- Based on simulations, the 75 A per phase screening threshold will result in a maximum instantaneous peak hot spot temperature of 172°C. However, IEEE Std C57.91- 2011 limits assume short term emergency operation (typically 30 minutes). As illustrated in **Figure 2**, simulations of the 75 A per phase screening threshold result in 30-minute duration hot spot temperatures of about

155°C. The threshold provides an added measure of conservatism in not taking into account the duration of hot spot temperatures.

- The models used in the determination of the threshold are conservative but technically justified.
- Winding hot spots are not the limiting factor in terms of hot spots due to half-cycle saturation, therefore the screening criterion is focused on metallic part hot spots only.

The 75 A per phase screening threshold was determined using single-phase transformers, but is applicable to all types of transformer construction. While it is known that some transformer types such as three-limb, three-phase transformers are intrinsically less susceptible to GIC, it is not known by how much, on the basis of experimentally-supported models.

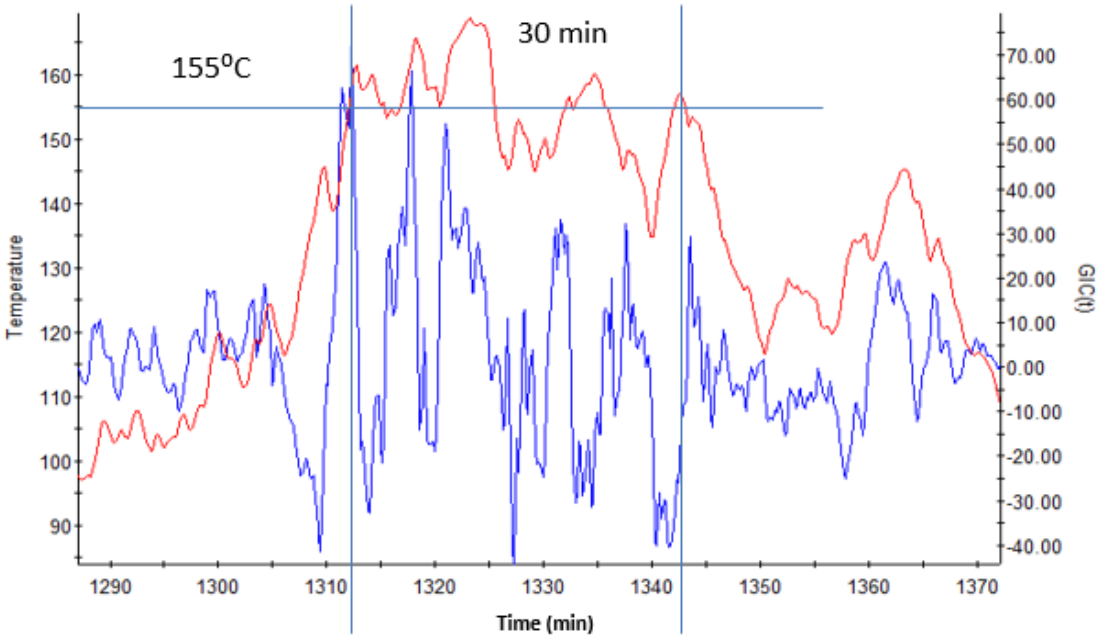


Figure 2: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: metallic hot spot temperature. Blue: GIC(t) that produces the maximum hot spot temperature with peak GIC(t) scaled to 75 A/phase.

Appendix

The envelope used for thermal screening (Figure 1) is derived from two thermal models. The first is based on laboratory measurements carried out on 500/16.5 kV 400 MVA single-phase Static Var Compensator (SVC) coupling transformer [2]. Temperature measurements were carried out at relatively small values of GIC (see **Figure 3**). The asymptotic thermal response for this model is the linear extrapolation of the known measurement values. Although the near-linear behavior of the asymptotic thermal response is consistent with the measurements made on a Fingrid 400 kV 400 MVA five-leg core-type fully-wound transformer [3] (see **Figures 4 and 5**), the extrapolation from low values of GIC is very conservative, but reasonable for screening purposes.

The second transformer model is based on a combination of measurements and modeling for a 400 kV 400 MVA single-phase core-type autotransformer [4] (see **Figures 6 and 7**). The asymptotic thermal behavior of this transformer shows a "down-turn" at high values of GIC as the tie plate increasingly saturates but relatively high temperatures for lower values of GIC. The hot spot temperatures are higher than for the two other models for GIC less than 125 A per phase.

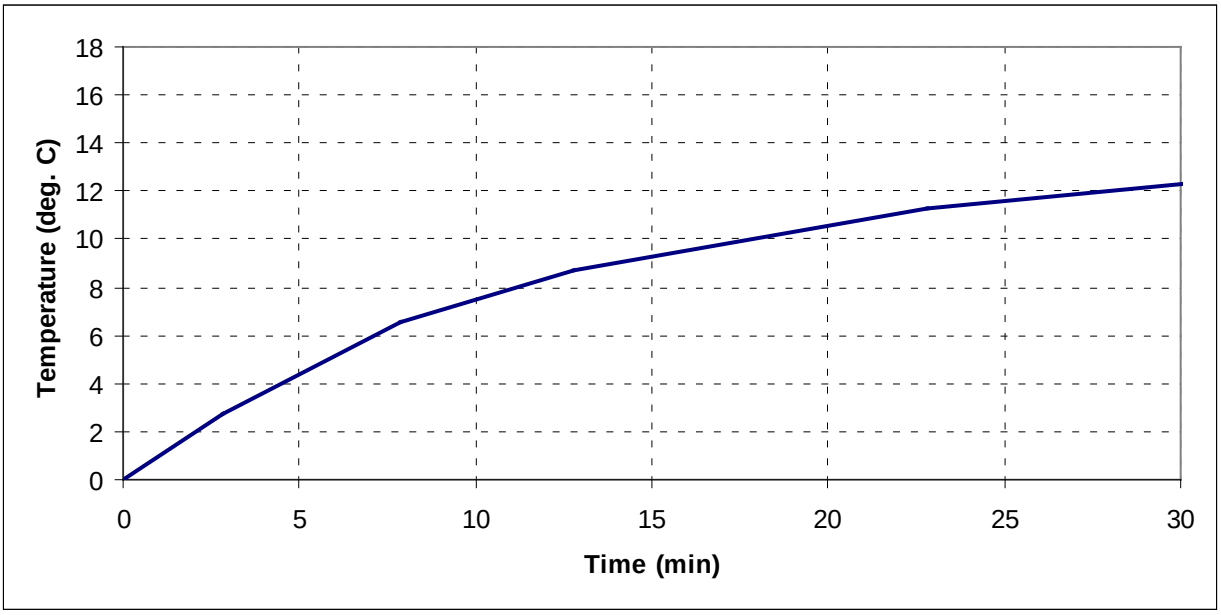


Figure 3: Thermal step response of the tie plate of a 500 kV 400 MVA single-phase SVC coupling transformer to a 5 A per phase dc step.

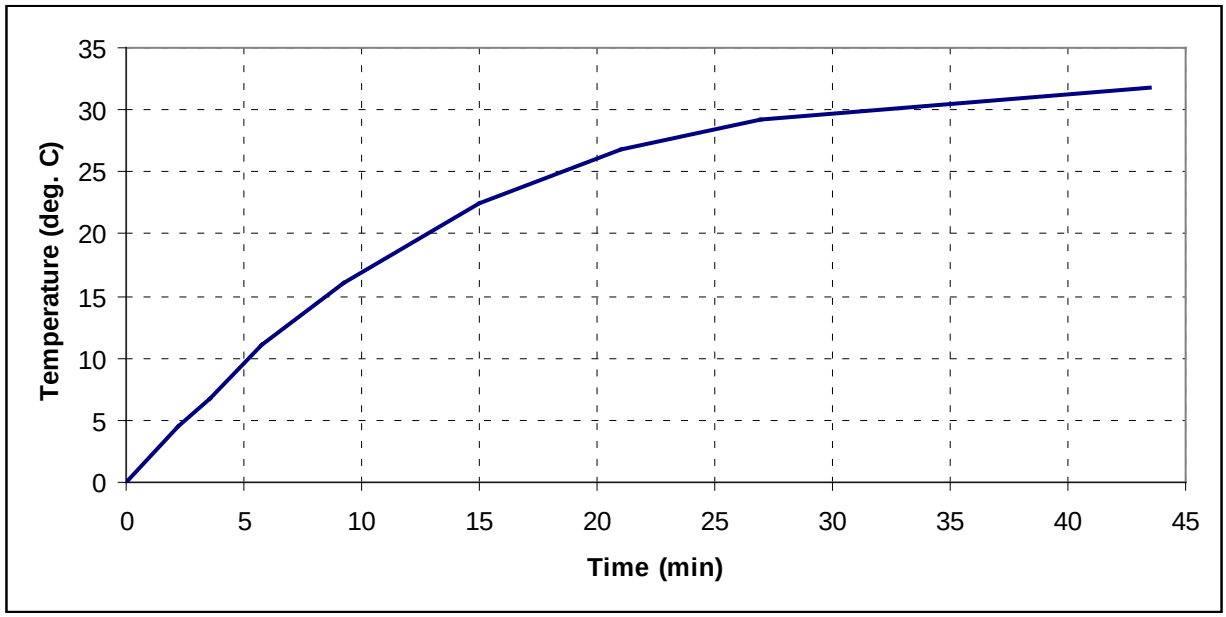


Figure 4: Step thermal response of the top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer to a 16.67 A per phase dc step.

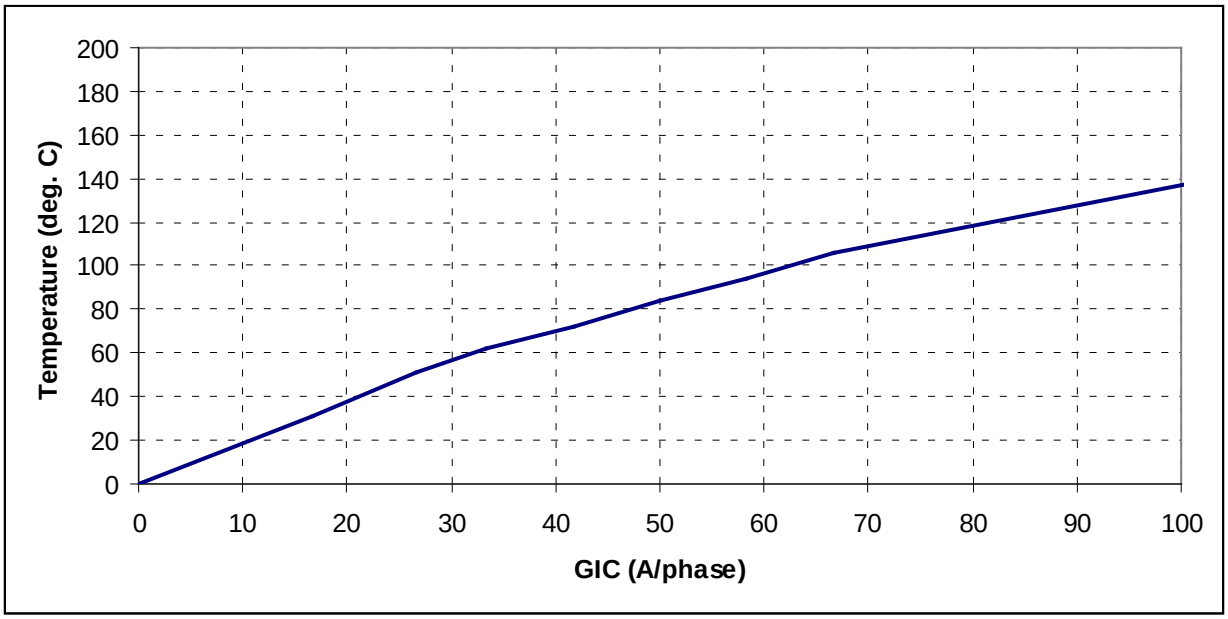


Figure 5: Asymptotic thermal response of the top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer.

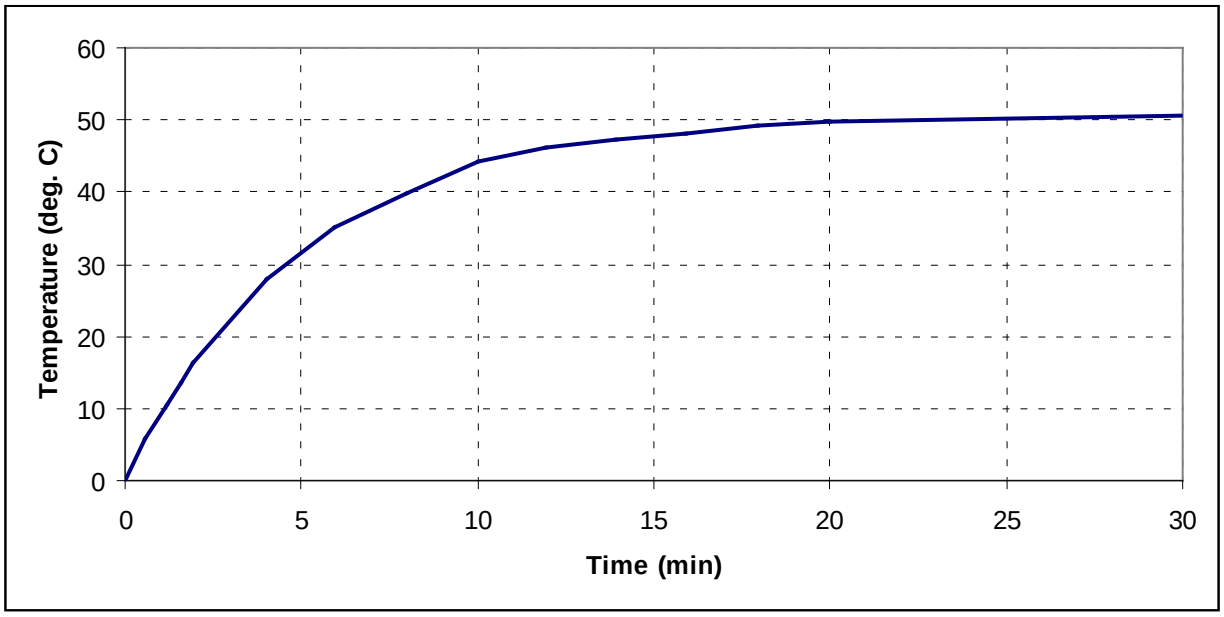


Figure 6: Step thermal response of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer to a 10 A per phase dc step.

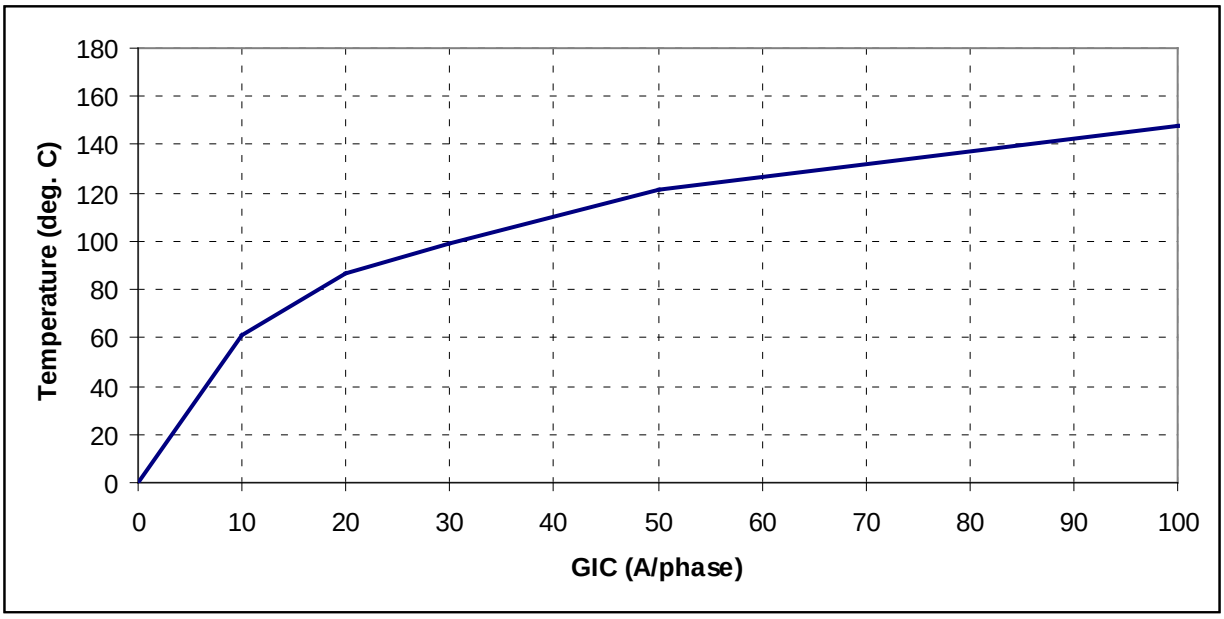


Figure 7: Asymptotic thermal response of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer.

The envelope in **Figure 1** can be used as a conservative thermal assessment for effective GIC values of 75 A per phase and greater (see Table 2).

Table 2: 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

For instance, if effective GIC is 130 A per phase and oil temperature is assumed to be 80°C, peak hot spot temperature is 193°C. This value is below the 200°C IEEE Std C57.91-2011 threshold for short time emergency loading and this transformer will have passed the thermal assessment. If the full heat run oil temperature is 67°C at maximum ambient temperature, then 150 A per phase of effective GIC translates into a peak hot spot temperature of 200°C and the transformer will have passed. If the limit is lowered to 180°C to account for the condition of the transformer, then this would be an indication to "sharpen the pencil" and perform a detailed assessment. Some methods are described in Reference [1].

The temperature envelope in Figure 1 corresponds to the values of effective GIC that result in the highest temperature for the benchmark GMD event. Different values of effective GIC could result in lower temperatures using the same model. For instance, the difference in upper and lower bounds of peak temperatures for the SVC coupling transformer model for 150 A per phase is approximately 30°C. In this case, GIC(t) should be generated to calculate the peak temperatures for the actual configuration of the transformer within the system as described in Reference [1]. Alternatively, a more precise thermal assessment could be carried out with a thermal model that more closely represents the thermal behavior of the transformer under consideration.

References

[1] Transformer Thermal Impact Assessment 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

[2] 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, Jan. 2013.

[3] 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.

[4] J. Raith, S. Ausserhofer: "GIC Strength verification of Power Transformers in a High Voltage Laboratory", GIC Workshop, Cape Town, April 2014

[5] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

Standard Requirement	OC	PC	RE	NERC	Avg.	OC	PC	RE	NERC	Avg.	Max Dif
	Content Questions					Quality Questions					
BAL-001-2 , R1	3	3	3	3	3.00	12	11	11	12	11.5	**1**
BAL-001-2 , R2	3	3	3	3	3.00	12	11	11	10	11	**2**
EOP-010-1, R1	3	3	3	3	3.00	12	12	12	12	12	**0**
EOP-010-1, R2		3	2	3	2.67	12	12	8	11	10.75	**4**
EOP-010-1, R3.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
EOP-011-1, R1.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
EOP-011-1, R2.	3	3	3	3	3.00	12	12	12	12	12	**0**
EOP-011-1, R3.	3	3	1	3	2.50	12	12	11	10	11.25	**2**
EOP-011-1, R4.	3	3	1	3	2.50	12	12	12	10	11.5	**2**
EOP-011-1, R5.	3	3	2	3	2.75	12	12	11	12	11.75	**1**
EOP-011-1, R6.	3	3	2	3	2.75	12	12	12	10	11.5	**2**
FAC-008-3, R1	3	3	3	3	3.00	12	11	9	9	10.25	**3**
FAC-008-3, R2.		3	3	3	3.00		11	11	12	11.33	**1**
FAC-008-3, R3.	3	3	3	3	3.00	12	11	11	12	11.5	**1**
FAC-008-3, R6.	3	3	3	3	3.00	12	11	10	11	11	**2**
FAC-008-3, R7.	3	3	2	2	2.50	12	11	10	10	10.75	**2**
FAC-008-3, R8.	3	3	3	2	2.75	10	11	10	10	10.25	**1**
INT-004-3.1 , R3.	3	3		3	3.00	12	10	12	11	11.25	**2**
INT-006-4, R1	3	3	3	3	3.00	12	10	11	11	11	**2**
INT-006-4, R2	3	3	3	3	3.00	12	10	11	12	11.25	**2**
INT-006-4, R3.	3	3	3	3	3.00	12	11	11	12	11.5	**1**
INT-006-4, R4	3	3	3	3	3.00	12	11	10	12	11.25	**2**
INT-006-4, R5	3	3	3	3	3.00	12	11	12	12	11.75	**1**
INT-009-2.1, R1	3	3	3	3	3.00	12	12	12	10	11.5	**2**
INT-009-2.1, R2	3	3	3	3	3.00	12	12	12	12	12	**0**
INT-009-2.1, R3.	3	3	3	3	3.00	12	12	12	12	12	**0**
INT-010-2.1, R1	3	3	3	3	3.00	12	8	10	12	10.5	**4**
INT-010-2.1, R2	3	3	3	3	3.00	12	8	12	12	11	**4**
INT-010-2.1, R3.	3	3	3	3	3.00	12	8	12	10	10.5	**4**
NUC-001-3, R1	3	3	3	3	3.00	12	12	12	12	12	**0**
NUC-001-3, R2.	3	3	3	3	3.00	12	12	12	12	12	**0**
NUC-001-3, R3.	3	3	2	3	2.75	12	12	12	12	12	**0**
NUC-001-3, R4.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
NUC-001-3, R5.	3	3	3	3	3.00	12	12	12	12	12	**0**
NUC-001-3, R6.	3	3	3	3	3.00	12	12	12	12	12	**0**

Standard Requirement	OC	PC	RE	NERC	Avg.	OC	PC	RE	NERC	Avg.	Max Dif
	Content Questions					Quality Questions					
NUC-001-3, R7.	3	3	3	3	3.00	12	12	12	12	12	**0**
NUC-001-3, R8.	3	3	3	3	3.00	12	12	12	12	12	**0**
NUC-001-3, R9	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PER-003-1, R1.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
PER-003-1, R2.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
PER-003-1, R3.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
PER-004-2, R1.	3	3	2	3	2.75	12	11	10	12	11.25	**2**
PER-004-2, R2.	3	3		3	3.00	7	7	12	12	9.5	**5**
PRC-004-5(i), R1.	3	3	2	3	2.75	12	12	12	11	11.75	**1**
PRC-004-5(i), R2.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PRC-004-5(i), R3.	3	3	3	3	3.00	12	12	11	10	11.25	**2**
PRC-004-5(i), R4.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-004-5(i), R5.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-004-5(i), R6.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-005-6, R1.	3	3	2	3	2.75	12	12	11	10	11.25	**2**
PRC-005-6, R2.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-005-6, R3.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-005-6, R4.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-005-6, R5.	3	2	3	3	2.75	12	6	12	10	10	**6**
PRC-006-2 , R1.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-006-2 , R2.	2	2	2	2	2.00	12	12	11	11	11.5	**1**
PRC-006-2 , R3.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-006-2 , R4.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PRC-006-2 , R5.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PRC-006-2 , R6.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PRC-006-2 , R7.	3	3	3	3	3.00	12	12	12	12	12	**0**
PRC-006-2 , R8.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-006-2 , R9.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
PRC-006-2 , R10.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PRC-006-2 , R11.	3	3	3	3	3.00	12	12	12	12	12	**0**
PRC-006-2 , R12.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PRC-006-2 , R13.	3	3	3	3	3.00	12	12	12	12	12	**0**
PRC-010-2, R1.	3	3	1	3	2.50	12	12	12	10	11.5	**2**
PRC-010-2, R2.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
PRC-010-2, R3.	3	3	1	3	2.50	12	12	9	12	11.25	**3**

Standard Requirement	OC	PC	RE	NERC	Avg.	OC	PC	RE	NERC	Avg.	Max Dif
	Content Questions					Quality Questions					
PRC-010-2, R4.	3	3	1	3	2.50	12	12	12	12	12	**0**
PRC-010-2, R5.	3	3	1	3	2.50	12	12	12	12	12	**0**
PRC-010-2, R6.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-010-2, R7.	3	3	3	3	3.00	12	12	12	12	12	**0**
PRC-010-2, R8.	3	3	3	3	3.00	12	12	12	12	12	**0**
PRC-019-2, R1.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-019-2, R2.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-023-4, R1.	3	3	3	3	3.00	12	12	9	12	11.25	**3**
PRC-023-4, R2.	3	3	2	3	2.75	12	12	9	12	11.25	**3**
PRC-023-4, R3.	3	3	2	3	2.75	12	12	11	12	11.75	**1**
PRC-023-4, R4.	3	3	2	3	2.75	12	12	10	12	11.5	**2**
PRC-023-4, R5.	3	3	3	3	3.00	12	12	11	8	10.75	**4**
PRC-023-4, R6.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-024-2, R1.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-024-2, R2.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-024-2, R3.	3	3	3	3	3.00	12	12	10	12	11.5	**2**
PRC-024-2, R4.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-025-1, R1.	3	3	2	3	2.75	12	12	10	12	11.5	**2**
VAR-001-4.1, R1.	3	3	3	3	3.00	12	12	10	9	10.75	**3**
VAR-001-4.1, R2.	3	3	3	3	3.00	12	12	11	10	11.25	**2**
VAR-001-4.1, R3.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
VAR-001-4.1, R4.	3	3	3	2	2.75	12	12	9	11	11	**3**
VAR-001-4.1, R5.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
VAR-001-4.1, R6.	3	3	2	3	2.75	12	12	12	11	11.75	**1**
VAR-002-4, R1.	3	3	3	3	3.00	12	12	9	12	11.25	**3**
VAR-002-4, R2.	3	3	3	3	3.00	12	12	12	12	12	**0**
VAR-002-4, R3.	3	3	3	3	3.00	12	12	12	12	12	**0**
VAR-002-4, R4.	3	3	3	3	3.00	12	12	10	12	11.5	**2**
VAR-002-4, R5.	3	3	3	3	3.00	12	12	12	12	12	**0**
VAR-002-4, R6.	3	3	3	3	3.00	12	12	10	11	11.25	**2**

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Frequently Asked Questions

Enhanced Periodic Review Standing Review Team – Standards Grading

The following questions and answers are intended to facilitate understanding about the Enhanced Periodic Review Standing Review Team – Standards Grading process. Please contact Mat Bunch (via email) or at (404) 446-9785 with any additional questions you may have.

Enhanced Periodic Review Standing Review Team – Standards Grading process FAQs

Q1: Why are standards being graded?

A1. The Standards Committee (SC), at its March 9, 2016 meeting, endorsed the use of the grading tool used by the Independent Expert Review Panel (IERP) as the metric to grade all NERC Reliability Standards. The Enhanced Periodic Review Standing Team (EPRST), with the SC chair facilitating the meetings, conducted an initial grading of all currently-enforceable Reliability Standards with requirements that have been subject to enforcement in the United States for at least one year. The grading activity is conducted during pre-scheduled public meetings/calls open to stakeholders. The most up-to-date information can be found on the EPR project page.

The EPRST has completed its initial grading, which is posted for a 30-day industry comment period. The EPRST has sought input from stakeholders prior to finalizing the grading. The finalized grading will be appended to the Reliability Standards Development Plan (RSDP), which has been endorsed by the SC.

Q2: Who comprises the Standing Review Team (SRT)?

A2: The chairs of the SC, Operating Committee (OC), Planning Committee (PC), a representative for the Regional Entities, and NERC staff comprise the Enhanced Periodic Review Standing Review Team (EPRSRT). The primary role of the SC chair or the delegate is to facilitate the meetings and not to grade the standards. The SC chair (or the delegate) also assists to resolve differences of opinions.

Q3: What are the grades used for?

A3: The final grade will be an early input to future EPRs, along with additional information collected, as required under the EPR Template. If an EPR team recommends revising standard requirements that were graded in 2016, the SRT will re-grade those standard requirements based on the recommended revision. The re-graded requirements will also be posted for additional stakeholder comment prior to final SRT grading.

Q4. What is the grading tool?

A4. The grading tool is based on the grading tool from the 2013 Standards Independent Experts Review Project. The SC endorsed using the same decisions-tree and grading criteria, with the addition of one quality question on cost effectiveness. For purposes of the 2016 standards grading, the cost-effectiveness quality question does not contribute to the final numeric grade for quality. The grading tool completed by the EPRSRT is available on the project web page.

Q5: What are the eligibility criteria for a standard to be graded?

A5: All requirements of a Reliability Standard must have been in effect, based on the implementation/compliance dates approved by the applicable governmental authority, for at least a year. In some instances, a standard may be eligible if:

- It has been a year since the effective date of the order approving that standard if entities are "early adopting" the requirements as they implement their programs to prepare for the effective date; or
- If the standard is a revision to a standard that has been in effect greater than a year.

For example, in some cases, the EPRSRT is grading a standard that is subject to future enforcement, but that is because it is a revised version of a standard that covers materially the same or similar topics. In the case of an entirely new standard, for example, PRC-026-1 regarding stable power swings, the subject matter has not been directly covered by a previous standard and is not being graded at this time.

Q6: How did the EPRSRT determine the grades that are posted?

A6: Each EPRSRT member used the posted standards grading tool to develop initial grades, which the team discussed at the June 23, 2016 public meeting in Atlanta. The EPRSRT focused its discussions on developing consensus grades on standards where individual grading variances equaled or exceeded one point for content or three points for quality. The EPRSRT requested comments from industry on specific standards grades where the EPRSRT was unable to reach strong consensus or desired specific stakeholder input before finalizing a consensus position. In those instances the EPRSRT believes that additional input from an industry perspective would assist the team's final grading.

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Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.net

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard	
Proposed Standard:	Project 2015-10 Single Points of Failure TPL-001 SPCS and SAMS recommendations in response to FERC Order No. 754 (TPL-001-4)
Date Submitted:	October 05, 2015

SAR Requester Information			
Name:	Philip B. Winston, PE and John M Simonelli		
Organization:	Southern Company and ISO New England, Inc., respectively.		
Telephone:	404-608-5989--primary	E-mail:	pbwinsto@southernco.com--primary

SAR Type (Check as many as applicable)	
☐ New Standard	☐ Withdrawal of existing Standard
☒ Revision to existing Standards	☐ Urgent Action

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Modifications have been ~~identified~~recommended to Reliability Standard TPL-001-4 based on the following: Item 1: The System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS) conducted a comprehensive assessment of the study of protection system single

SAR Information

points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.

As such, regarding single points of failure in protection systems, the SPCS and the SAMS make the following recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process identified in the NERC Rules of Procedure:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure[13]" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure[13]" with "a component failure of a Protection System[13]."
- Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."[1]
- Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

[1] See Order 754 (NERC website) Requests for Clarifications and Responses (http://www.nerc.com/pa/Stand/Order%20754%20DL/Order_754-Requests_for_Clarification_and_Responses_July2013.pdf).

SAR Information
~~Item 2: In addition, on October 17, 2013 the Commission issued Order No. 786, which included two directives related to TPL-001-4. The two directives are as follows:~~ ~~Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments~~ ~~Paragraph 89 directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4."~~ Item ~~3~~2: Further, references to MOD-010 and MOD_012 in Requirement R1 would need to be replaced with MOD-032 due to July 2016 retirement of those standards. In addition, on October 17, 2013 the Commission issued Order No. 786, which included two directives related to TPL-001-4. The two directives are as follows: • Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments • Paragraph 89 directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4." Purpose or Goal (How does this request propose to address the problem described above?): The ~~primary~~ goal of this SAR is to: 1. Consider the~~ appoint a Standard Drafting Team (SDT) to address~~ recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) as identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request"; 2. Address the two FERC directives from Order No. 786; and 3. Update the references to the MOD Reliability Standards in TPL-001. ~~."~~ Identify the Objectives of the proposed standards' requirements (What specific reliability deliverables are required to achieve the goal?): Provide clear, unambiguous requirements and Results-based Reliability Standards that will: (1) reflect ~~condiseration~~consideration of~~standards to address~~ the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;" (ii) address the two FERC directives from Order No. 786 ~~citd~~cited above; and (iii) and update the references to the MOD Reliability Standards cited in TPL-001. ~~."~~

SAR Information
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall consider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request", address the two FERC directives, update the references to the MOD Standards,~~"~~ and revise standards, requirements, attachments, Violation Risk Factors, Violation Severity Levels, and implementation plans as appropriate. The SDT shall consider retirements to requirements under Paragraph 81 criteria. In addition, the SDT shall work with compliance on an accompanying RSAW to address each of the standard's requirements and measures.
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 consider~~address~~ the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request." This~~ The SDTs execution of this SAR would, in addition, consider retirements to requirements under Paragraph 81 criteria. The SPCS and SAMS~~ report ~~titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request"~~ is incorporated in its entirety into this SAR~~,~~ so as not to unnecessarily repeat or paraphrase the substance of the report. In addition, the SDTs execution of this SAR would consider retirements to requirements under Paragraph 81 criteria.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ 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.

Reliability Functions		
☐	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.
☐	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.

Reliability and Market Interface Principles	
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	N/A

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

A. Introduction

1. **Title: Transmission Operations**

2. **Number: TOP-001-~~3~~4**

3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Operator

   4.3. Generator Operator

   4.4. Distribution Provider

5. **Effective Date:**

   See Implementation Plan~~.~~

~~**6. Background:**~~

~~See Project 2014-03 project page.~~

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and

provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings,

electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining SOL exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4, which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability are monitored. These facilities should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

R10. Each Transmission Operator shall perform the following ~~as necessary~~ for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. ~~Within its Transmission Operator Area, monitor~~ Monitor Facilities within its Transmission Operator Area; ~~and~~

10.2. Monitor the status of ~~Special Protection Systems~~Remedial Action Schemes within its Transmission Operator Area;

~~10.1.~~**10.3.** Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;~~and~~

10.4. ~~Outside its Transmission Operator Area, o~~Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

~~**10.2.** and the status of Special Protection Systems.~~

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized ~~status, voltages, and flow~~ data ~~for Facilities and the status of Special Protection Systems~~ as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of ~~Special Protection System~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of ~~Special Protection System~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

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

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of infrastructure that will provide continued functionality despite failure or malfunction of an individual component within the Transmission Operator's (TOP) Control Center. Requirement R20 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the TOP Control Center.

Infrastructure that is not within the TOP's Control Center is not addressed by the proposed requirement.

R19. Each Transmission Operator shall have data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning

Analyses.~~the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.~~ *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability in its Transmission Operator Area~~perform its Operational Planning Analyses.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order to perform it Real-time monitoring and Real-time Assessments as specified in the requirement.

Rationale for Requirement R21: The proposed requirement addresses directives for testing of data exchange capabilities (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R21. Each Transmission Operator shall test its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its data exchange capabilities specified in Requirement R20 for redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

Rationale for Requirements R22 and R23: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of infrastructure that will provide continued functionality despite failure or malfunction of an individual component within the Balancing Authority's (BA) Control Center. Requirement R23 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the BA Control Center.

Infrastructure that is not within the BA's Control Center is not addressed by the proposed requirement.

~~R20.~~R22. Each Balancing Authority shall have data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to develop its Operating Plan for next-day operations.~~maintain reliability in its Balancing Authority Area.~~ *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M2~~0~~2. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability in its Balancing Authority Area~~develop its Operating Plan for next-day operations.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order to perform it Real-time monitoring and analysis functions as specified in the requirement.

Rationale for Requirement R24: The proposed requirement addresses directives for testing of data exchange capabilities (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R24. Each Balancing Authority shall test its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its data exchange capabilities specified in Requirement R23 for redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~As defined in the NERC Rules of Procedure,~~ "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, 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 ~~the NERC~~ Reliability Standards in their respective jurisdictions.

~~1.2. Compliance Monitoring and Assessment Processes~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be~~

~~used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~1.3.~~1.2. ~~Data~~ 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 following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.~~

Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and ~~R15 through R20 and~~ Measure M1 through M11~~, and M15 through M20~~ for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ~~ninety~~ 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.

~~and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.~~

Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence ~~and~~ that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.

Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R20, and Measure M15

through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Balancing Authority shall each keep data or evidence for each applicable Requirement R22 through R23, and Measure M22 through M23 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

~~If a Balancing Authority, Transmission Operator, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.~~

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

1.3. Compliance Monitoring and Enforcement Program

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

~~1.4. Additional Compliance Information~~

~~None.~~

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities,	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Emergency on respective Balancing Authority Areas.	resulted in, an Emergency on respective Balancing Authority Areas.
R9	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment capabilities, or associated communication channels between the affected entities.
R10	The Transmission Operator did not monitor, obtain, or utilize one of the items listed in Requirement R10, Part 10.1 through 10.6.~~N/A~~	The Transmission Operator did not monitor, obtain, or utilize two of the items listed in Requirement R10, Part 10.1~~.~~ through 10.6. ~~OR,~~ ~~The Transmission Operator did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.~~	The Transmission Operator did not monitor, obtain, or utilize three of the items listed in Requirement R10, Part 10.1 through 10.6~~ and did not obtain and utilize one of the items listed in Requirement R10, Part 10.2~~.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items listed in Requirement R10 Part 10.1 through 10.6.~~Facilities and the status of Special Protection Systems within its Transmission Operator Area and did not obtain and utilize data deemed as necessary from outside its Transmission Operator Area.~~
R11	N/A	N/A	The Balancing Authority did not monitor the status of ~~Special Protection System~~Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			within its Balancing Authority Area and support Interconnection frequency.	
R12	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				instances where there was a difference in SOLs.
R19	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's Control	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time monitoring and Real-time Assessments as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Center, as specified in the Requirement.	
R21	The Transmission Operator tested its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The Transmission Operator tested its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Transmission Operator tested its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The Transmission Operator did not test its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month; OR The Transmission Operator tested its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.
~~R20~~R 22	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with one identified entity,	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with two identified	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with three identified entities, or more than 10% or	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with four or more identified entities or greater than 15% of the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	or 5% or less of the applicable entities, whichever is greater.	entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	less than or equal to 15% of the applicable entities, whichever is greater.	applicable entities, whichever is greater.
R23	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure within the Balancing Authority's Control Center, as specified in the Requirement.	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.
R24	The Balancing Authority tested its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar	The Balancing Authority tested its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar	The Balancing Authority tested its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month but, following an	The Balancing Authority did not test its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month;

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	OR The Balancing Authority tested its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The ~~SDT~~Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	
4	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of TOP-001-4, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of TOP-001-4, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of TOP-001-3 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

~~**Rationale:**~~

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

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

Rationale for Requirement R13:

The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:

The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20:

Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**

2. **Number:** IRO-002-~~4~~5

3. **Purpose:** To ~~Provide~~ provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.

4. **Applicability**

   4.1. Functional Entities

   ~~4.1.~~4.1.1 Reliability Coordinator

5. **Effective Date:**

   See Implementation Plan~~.~~

~~**6. Background:**~~

~~See the Project 2014~~2016 ~~03 01~~.

B. Requirements and Measures

Rationale for Requirements R1 and R2: The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of infrastructure that will provide continued functionality despite failure or malfunction of an individual component within the Reliability Coordinator's (RC) Control Center. Requirement R2 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the RC Control Center.

Infrastructure that is not within the RC's Control Center is not addressed by the proposed requirement.

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses~~, Real-time monitoring, and Real-time Assessments~~. *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning~~, Same-Day Operations, Real-time Operations~~]*

M1. Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to a document that lists its data exchange capabilities

with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its ~~operational~~ Operational Planning Analyses~~, Real-time monitoring, and Real-time Assessments~~.

R2. Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to a document that lists its data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, as specified in the requirement.

Rationale for Requirement R3: The revised requirement addresses directives for testing of data exchange capabilities (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

R3. Each Reliability Coordinator shall test its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that it tested its data exchange capabilities specified in Requirement R2 for redundant functionality; and if the test was unsuccessful, initiated action within two hours to restore redundant functionality. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

~~R2.~~R4. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

~~M1.~~M4. Each Reliability Coordinator shall, have and provide upon request evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

~~R3.~~R5. Each Reliability Coordinator shall monitor Facilities, the status of ~~Special Protection System~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any ~~-~~System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of ~~Special Protection System~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

~~R4.~~R6. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M6. The Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, 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. Compliance Monitoring and Assessment Processes:~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~1.3.~~1.2. ~~Data~~ Evidence Retention

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

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

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

The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and ~~R3~~R4 and Measures M1, M2, and ~~M3~~M4.

The Reliability Coordinator shall retain evidence for Requirement R3 and Measure M3 for the most recent 12 calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

The Reliability Coordinator shall keep data or evidence for Requirements R5 and R6 ~~R4~~ and Measures M5 and M6 ~~M4~~ for the current calendar year and one previous calendar year.

~~If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.~~

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

1.3. Compliance Monitoring and Enforcement Program

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

~~1.4. Additional Compliance Information~~

~~None.~~

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2	N/A	N/A	The Reliability Coordinator had data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments, but did not have redundant and	The Reliability Coordinator did not have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments as specified in the requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			diversely routed data exchange infrastructure within the Reliability Coordinator's Control Center, as specified in the requirement.	
R3	The Reliability Coordinator tested its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The Reliability Coordinator tested its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The Reliability Coordinator tested its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The Reliability Coordinator did not test its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month; OR The Reliability Coordinator tested its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month but, following an unsuccessful test, did not initiate action to restore the redundant functionality in more than 8 hours.
~~R2~~R4	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
~~R3~~R5	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of ~~Special Protection System~~Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
~~R4~~R6	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The Implementation Plan and other project documents can be found on the project page.~~None.~~

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
2	October 17, 2008	Adopted by NERC Board of Trustees	Deleted R2, M3 and associated compliance elements as conforming changes associated with approval of IRO-010-1. Revised as part of IROL Project
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised

3	August 4, 2011	Approved by Board of Trustees	Retired R1-R8 under Project 2006-06.
4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	
5	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

During development of IRO-002-5, text boxes are embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption of IRO-002-5, the text from the rationale text boxes will be moved to this section.

Rationale text from the development of IRO-002-4 in Project 2014-03 follows. Additional information can be found on the Project 2014-03 project page.

~~**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.~~

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Requirements:

The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The ~~SDT~~Project 2014-03 SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

Rationale for R2:

Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

Rationale for ~~R4~~R6:

Requirement ~~R4~~ R6 was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

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Implementation Plan

Project 2016-01 Modifications to TOP and IRO Standards
Reliability Standards IRO-002-5 and TOP-001-4

Applicable Standard(s)

- IRO-002-5 - Reliability Coordination - Monitoring and Analysis
- TOP-001-4 - Transmission Operations

Requested Retirement(s)

- IRO-002-4 - Reliability Coordination - Monitoring and Analysis
- TOP-001-3 - Transmission Operations

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator
- Generator Operator
- Distribution Provider

Background

On November 19, 2015, the Federal Energy Regulatory Commission (FERC) issued Order No. 817 approving nine revised or new TOP and IRO Reliability Standards from Project 2014-03 that addressed previously-identified reliability issues and concerns. In approving the standards, FERC also directed development of modifications to TOP and IRO standards to address specific concerns related to: (i) Transmission Operator monitoring of some non-Bulk Electric System (non-BES) elements needed for reliable operations, and (ii) redundancy in data exchange capabilities used by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable operations.

General Considerations

The three-month implementation period for IRO-002-5 provides Reliability Coordinators with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality. The proposed implementation plan presumes that IRO-002-4 is effective, or will become effective, on or before the effective date of IRO-002-5.

The 12-month implementation period for TOP-001-3 provides Transmission Operators (TOP) with time to revise and distribute data specifications required by TOP-003-3 Requirement R1 to include non-BES data identified by the TOP, and receive data from entities responsible for providing the data as required by TOP-003-3 Requirement R5. The implementation period also provides TOPs and Balancing Authorities (BAs) with time to establish and document data exchange capabilities that are redundant and diversely routed, and to implement testing processes and procedures for redundant functionality.

Effective Date

IRO-002-5
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 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 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-001-4
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

IRO-002-4
Reliability Standard IRO-002-4 shall be retired immediately prior to the effective date of IRO-002-5 in the particular jurisdiction in which the revised standard is becoming effective.

TOP-001-3
Reliability Standard TOP-001-3 shall be retired immediately prior to the effective date of TOP-001-4 in the particular jurisdiction in which the revised standard is becoming effective.

Order No. 817 Citation	Directive / Guidance	Resolution
P 35	Revise Reliability Standard TOP-001-3, Requirement R10 to require real-time monitoring of non-BES facilities.	The directive is addressed in proposed TOP-001-4 Requirement R10. Parts 10.3 and 10.6 cover non-BES facilities. ***Proposed TOP-001-4*** **R10.** Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **10.1.** Monitor Facilities within its Transmission Operator Area; **10.2.** Monitor the status of Remedial Action Schemes within its Transmission Operator Area; **10.3.** Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator; **10.4.** Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator; **10.5.** Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and **10.6.** Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

Order No. 817 Citation	Directive / Guidance	Resolution
P 47	Modify Reliability Standards TOP-001-3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing. In addition, [the Commission directs] NERC to clarify that "redundant infrastructure" for system monitoring in Reliability Standards IRO-002-4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities.	Proposed TOP-001-4 Requirements R20 and R23 address the directive for Transmission Operators (TOP) and Balancing Authorities (BA), respectively. For consistency, the Standards Drafting Team (SDT) developed proposed IRO-002-5 Requirement R2 to address the directive for Reliability Coordinators (RCs) rather than develop a modification to IRO-002-4 Requirement R4. ***Proposed TOP-001-4*** **R20.** Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments. **R23.** Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions. ***Proposed IRO-002-5*** **R2.** Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and

Order No. 817 Citation	Directive / Guidance	Resolution
		with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments.
P 51	Develop a modification to the TOP and IRO standards that addresses a data exchange capability testing framework for the data exchange capabilities used in the primary control centers to test the alternate or less frequently used data exchange capabilities of the reliability coordinator, transmission operator and balancing authority.	The directive is addressed in proposed TOP-001-4 Requirements R21 and R24, and proposed IRO-002-5 Requirement R3. ***Proposed TOP-001-3*** **R21.** Each Transmission Operator shall test its data exchange capabilities specified in Requirement R20 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. **R24.** Each Balancing Authority shall test its data exchange capabilities specified in Requirement R23 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. ***Proposed IRO-002-5*** **R3.** Each Reliability Coordinator shall test its data exchange capabilities specified in Requirement R2 for redundant functionality at least once each calendar month. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2016-01 - Modifications to TOP and IRO 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 Reliability Standard requirements developed in Project 2016-01. 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.

Project 2016-01 Reliability Standards Requirements

The SDT developed new or revised requirements in IRO-002-5 and TOP-001-4 to address reliability objectives outlined in the project Standard Authorization Request (SAR). The VRF and VSL justification for these new and revised requirements is described below. VRF and VSL justification for requirements that were not modified in Project 2016-01 can be found on the Project 2014-03 Project Page.

VRF Justification

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirement is not directly connected to an area identified in the Blackout Report.

VRF Justification for TOP-001-4 Requirement R10	
Proposed VRF	**High**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The proposed VRF is unchanged from approved TOP-001-3 Requirement R10. Additionally, the requirement is similar to approved IRO-002-4 Requirement R3 which applies to Reliability Coordinators and is assigned a High VRF.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement addresses a single reliability objective and has a single VRF.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Operations Planning time horizon, which are not the subject of the Blackout Report recommendations regarding data exchange. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.

VRF Justification for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
Proposed VRF	**Medium**
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements address data exchange capabilities for the Operations Planning time horizon only, which is a significant change from approved IRO-002-4 Requirement R1 and TOP-001-3 Requirements R19 and R20 which apply to all operations time horizons. As proposed, the VRF will establish consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4. Data exchange capabilities for Same-day Operations and Real-time Operations are addressed in other requirements.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a Medium VRF. Failure to have data exchange capabilities necessary for performing Operational Planning Analysis or for developing an Operating Plan for next day operations could directly and adversely affect the electrical state or capability of the BES, or the ability to effectively control or restore the BES. However, this failure is unlikely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements address data exchange capabilities for the Same-day Operations and Real-time Operations time horizons. A High VSL is assigned to reflect the potential impact on the reliability of the BES consistent with the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirements improve upon requirements for data exchange capabilities in approved IRO-002-4 and TOP-001-3, which are assigned a High VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5 and proposed TOP-001-4.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for a High VRF. Failure to have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Control Center, for performing Real-time monitoring and analysis 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.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VRF Justification for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The requirements are not directly connected to an area identified in the Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirements have no sub-requirements and are assigned a single VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	These are new requirements. Approved COM-001-2.1 Requirement R9 requires periodic testing of Alternate Interpersonal Communications capability and is assigned a Medium VRF. As proposed, the VRF will maintain consistency among similar requirements in proposed IRO-002-5, proposed TOP-001-4, and approved COM-001-2.1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The requirements meet the criteria for Medium VRF. Failure to periodically test data exchange capabilities for redundant functionality could, under anticipated data exchange infrastructure failure, affect the ability to monitor and control the BES. However, failure to test data exchange capabilities for redundant functionality is not likely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirements address a single reliability objective and each has a single VRF.

VSL Justification

VSLs for TOP-001-4 Requirement R10			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator did not monitor, obtain, or utilize one of the items listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items listed in Requirement R10 Part 10.1 through 10.6.

VSL Justifications for TOP-001-4 Requirement 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	VSLs are comparable to approved TOP-001-3 Requirement R10.
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.

VSL Justifications for TOP-001-4 Requirement R10	
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.

VSLs for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22			
Lower	**Moderate**	**High**	**Severe**
The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with one identified entity, or 5% or less of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with two identified entities, or more than 5% or less than or equal to 10% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with three identified entities, or more than 10% or less than or equal to 15% of the identified entities, whichever is greater.	The applicable entity did not have data exchange capabilities for performing its Operational Planning Analyses (or developing its Operating Plan) with four or more identified entities or greater than 15% of the identified entities, whichever is greater.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements 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	VSLs are comparable to approved IRO-002-4 Requirement R1 and approved TOP-001-3 Requirements R19 and R20.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The applicable entity had data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), but did not have redundant and diversely routed data exchange infrastructure	The applicable entity did not have data exchange capabilities with its (Reliability Coordinator, Balancing Authority, and/or Transmission Operator, as specified in the requirement) and identified entities for performing Real-time monitoring (and Real-time Assessments or analysis functions), as specified in the Requirement.

		within its Control Center, as specified in the Requirement.	

VSL Justifications for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements 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	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do 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 VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

VSLs for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24			
Lower	**Moderate**	**High**	**Severe**
The applicable entity tested its data exchange capabilities for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	The applicable entity tested its data exchange capabilities for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	The applicable entity tested its data exchange capabilities for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	The applicable entity did not test its data exchange capabilities for redundant functionality at least once each calendar month; OR The applicable entity tested its data exchange capabilities for redundant functionality at least once each calendar month but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements 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 current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs are worded consistently with the corresponding requirements.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are not based on a cumulative number of violations.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This draft of CIP-003-7 is addressing the directive issued by the Federal Energy Regulatory Commission (Commission) in paragraph 73 of Order No. 822 which reads:

> [T]he Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term "direct" as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule approving revisions to the cybersecurity Critical Infrastructure Protection (CIP) standards.

Previously, the Guidelines and Technical Basis had approximately 10 pages of explanation and numerous reference models to describe different forms of direct vs. indirect access that could be used to determine whether Low Impact External Routable Connectivity existed and thus whether a Low Impact BES Cyber System Electronic Access Point (LEAP) was required.

In this revision, the term *Low Impact External Routable Connectivity* has been changed to *Low Impact External Routable Communication (LERC*) and simplified so that it is an attribute of a BES asset concerning whether there is routable protocol communications across the asset boundary without regard to 'direct vs. indirect' access that may occur. This greatly simplifies and clarifies the definition of LERC. It removes the dependency between the electronic access controls that may be in place and having those controls determine whether LERC exists or not. For those BES assets that have LERC, the SDT changed the requirement from requiring a LEAP to requiring electronic access controls to "permit only necessary electronic access to low impact BES Cyber Systems" (revised Attachment 1, Section 3.1) within the BES asset and expanded the Guidelines and Technical Basis with numerous examples of electronic access controls.

Given the modified definition of LERC and the proposed modifications in Reliability CIP-003-7, there is no longer a need for the NERC Glossary term Low Impact BES Cyber System Electronic Access Point (LEAP). Consequently, NERC is proposing that term for retirement.

In summary, the CIP Standard Drafting Team revised CIP-003-7, Attachments 1 and 2, Sections 2 and 3 and the associated High VSL for Requirement R2. Non-substantive errata changes were also made within the standard, including changing "ES-ISAC" to "E-ISAC".

Completed Actions	Date
Standard Authorization Request (SAR) approved	July 20, 2016
Draft 1 of CIP-003-7 posted for formal comment and initial ballot	July 21 – September 6, 2016

Anticipated Actions	Date
10-day final ballot	October, 2016
NERC Board of Trustees (BOT) adoption	November, 2016

A. Introduction

1. **Title:** Cyber Security — Security Management Controls

2. **Number:** CIP-003-~~6~~7

3. **Purpose:** To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

   4.1.1 Balancing Authority

   4.1.2 Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

   4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:

   4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

   4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

   4.1.2.2 Each Special Protection System (SPS) or Remedial Action Scheme (RAS) where the SPS or RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

   4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

   4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

   4.1.3 Generator Operator

   4.1.4 Generator Owner

4.1.5 Interchange Coordinator or Interchange Authority

4.1.6 Reliability Coordinator

4.1.7 Transmission Operator

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each SPS or RAS where the SPS or RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-003-~~6:~~ 7:

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESPs).

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates:

See Implementation Plan for CIP-003-~~6~~7.

6. Background:

Standard CIP-003 exists as part of a suite of CIP Standards related to cyber security, which require the initial identification and categorization of BES Cyber Systems and require organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems.

The term policy refers to one or a collection of written documents that are used to communicate the Responsible Entities' management goals, objectives and expectations for how the Responsible Entity will protect its BES Cyber Systems. The use of policies also establishes an overall governance foundation for creating a culture of security and compliance with laws, regulations, and standards.

The term documented processes refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in its documented processes, but it must address the applicable requirements.

The terms program and plan are sometimes used in place of documented processes where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as plans (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term program may refer to the organization's overall implementation of its policies, plans, and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Reliability Standards could also be referred to as a program. However, the terms program and plan do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high, medium, and low impact BES Cyber Systems. For example, a single

cyber security awareness program could meet the requirements across multiple BES Cyber Systems.

Measures provide examples of evidence to show documentation and implementation of the requirement. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the BES. A review of UFLS tolerances defined within Regional Reliability Standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

B. Requirements and Measures

R1. Each Responsible Entity shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 For its high impact and medium impact BES Cyber Systems, if any:

1.1.1. Personnel and training (CIP-004);

1.1.2. Electronic Security Perimeters (CIP-005) including Interactive Remote Access;

1.1.3. Physical security of BES Cyber Systems (CIP-006);

1.1.4. System security management (CIP-007);

1.1.5. Incident reporting and response planning (CIP-008);

1.1.6. Recovery plans for BES Cyber Systems (CIP-009);

1.1.7. Configuration change management and vulnerability assessments (CIP-010);

1.1.8. Information protection (CIP-011); and

1.1.9. Declaring and responding to CIP Exceptional Circumstances.

1.2 For its assets identified in CIP-002 containing low impact BES Cyber Systems, if any:

1.2.1. Cyber security awareness;

1.2.2. Physical security controls;

1.2.3. Electronic access controls for Low Impact External Routable ~~Connectivity~~Communication (LERC) and Dial-up Connectivity; and

1.2.4. Cyber Security Incident response

M1. Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.

R2. Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall implement one or more documented cyber security plan(s) for its low impact BES Cyber Systems that include the sections in Attachment 1. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

Note: An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required. Lists of authorized users are not required.

M2. Evidence shall include each of the documented cyber security plan(s) that collectively include each of the sections in Attachment 1 and additional evidence to demonstrate implementation of the cyber security plan(s). Additional examples of evidence per section are located in Attachment 2.

R3. Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the CIP Senior Manager.

R4. The Responsible Entity shall implement a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. An example of evidence may include, but is not limited to, a dated document, approved by the CIP Senior Manager, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information:

None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**Medium**	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address one of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 15 calendar months but did	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address two of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 16 calendar months but did	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address three of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address four or more of the nine topics required by R1. (R1.1) OR The Responsible Entity did not have any documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1. (R1.1) OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			complete this review in less than or equal to 16 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of	complete this review in less than or equal to 17 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of	calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact	The Responsible Entity did not complete its review of the one or more documented cyber security policies as required by R1 within 18 calendar months of the previous review. (R1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 18 calendar months of

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the previous approval. (R1.1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address one of the four topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as	the previous approval. (R1.1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address two of the four topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as	BES Cyber Systems, but did not address three of the four topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its	the previous approval. (R1.1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address any of the four topics required by R1. (R1.2) OR The Responsible Entity did not have any documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1. (R1.2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			required by Requirement R1 within 15 calendar months but did complete this review in less than or equal to 16 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 15 calendar months but did complete this	required by Requirement R1 within 16 calendar months but did complete this review in less than or equal to 17 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 16 calendar months but	assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1.2)	OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R1.2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			approval in less than or equal to 16 calendar months of the previous approval. (R1.2)	did complete this approval in less than or equal to 17 calendar months of the previous approval. (R1.2)		
R2	**Operations Planning**	**Lower**	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document cyber security awareness according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to reinforce cyber security practices at least once every 15 calendar months according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented one or more incident response plans	The Responsible Entity documented one or more Cyber Security Incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to test each Cyber Security Incident response plan(s) at least once every 36 calendar months according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented the determination of	The Responsible Entity failed to document or implement one or more cyber security plan(s) for its assets containing low impact BES Cyber Systems according to ~~CIP-003-6,~~ Requirement R2, Attachment 1. (R2~~)~~).

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Systems, but failed to document one or more Cyber Security Incident response plans according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to update each Cyber Security Incident response plan(s) within 180 days according to ~~CIP-003-6,~~ Requirement R2,	within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to include the process for identification, classification, and response to Cyber Security Incidents according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. ~~(R2)~~ (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document the determination of	whether an identified Cyber Security Incident is a Reportable Cyber Security Incident, but failed to notify the Electricity ~~Sector~~ Information Sharing and Analysis Center (~~ES~~E-ISAC) according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented ~~and implemented electronic access controls for LERC, but failed to implement a LEAP or permit inbound and outbound access according to CIP-003-6, Requirement R2, Attachment 1, Section 3. (R2)~~ ~~OR~~	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Attachment 1, Section 4. (R2)	whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity ~~Sector~~ Information Sharing and Analysis Center (~~ES~~E-ISAC) according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document physical security controls according to ~~CIP-003-6,~~	~~The Responsible Entity documented and implemented~~ electronic access controls for its assets containing low impact BES Cyber Systems, but failed to ~~document and~~ implement ~~authentication of all Dial-up Connectivity, if any, that provides~~the electronic access ~~to low impact BES Cyber Systems~~controls according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented the physical access controls for its assets containing low impact BES Cyber Systems, but failed to implement the physical	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document electronic access controls according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 3. (R2)	security controls according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 2. (R2)	
R3	**Operations Planning**	**Medium**	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in	The Responsible Entity has not identified, by name, a CIP Senior Manager. OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			document this change in less than 40 calendar days of the change. (R3)	days but did document this change in less than 50 calendar days of the change. (R3)	less than 60 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 60 calendar days of the change. (R3)
R4	**Operations Planning**	**Lower**	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 30 calendar days but did document this change in less than 40 calendar days of the change. (R4)	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 40 calendar days but did document this change in less than 50 calendar days of the change. (R4)	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 50 calendar days but did document this change in less than 60 calendar days of the change. (R4)	The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, but does not have a process to delegate actions from the CIP Senior Manager. (R4) OR The Responsible Entity has identified a delegate by name, title, date of delegation, and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						specific actions delegated, but did not document changes to the delegate within 60 calendar days of the change. (R4)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-003-5.	
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from Order No. 791 related to identify, assess, and correct

Version	Date	Action	Change Tracking
			language and communication networks.
6	2/12/15	Adopted by the NERC Board of Trustees.	Replaces the version adopted by the Board on 11/13/2014. Revised version addresses remaining directives from Order No. 791 related to transient devices and low impact BES Cyber Systems.
6	1/21/16	FERC Order issued approving CIP-003-6. Docket No. RM15-14-000	
7	TBD	Adopted by the NERC Board of Trustees.	Revised to address FERC Order 822 directive regarding definition of LERC

~~CIP-003-6 –~~ Attachment 1

Required Sections for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Responsible Entities shall include each of the sections provided below in the cyber security plan(s) required under Requirement R2.

Responsible Entities with multiple-impact BES Cyber Systems ratings can utilize policies, procedures, and processes for their high or medium impact BES Cyber Systems to fulfill the sections for the development of low impact cyber security plan(s). Each Responsible Entity can develop a cyber security plan(s) either by individual asset or groups of assets.

Section 1. Cyber Security Awareness: Each Responsible Entity shall reinforce, at least once every 15 calendar months, cyber security practices (which may include associated physical security practices).

Section 2. Physical Security Controls: Each Responsible Entity shall control physical access, based on need as determined by the Responsible Entity, to (1) the asset or the locations of the low impact BES Cyber Systems within the asset ~~and (2) the Low Impact BES Cyber System Electronic Access Points (LEAPs),~~, and (2) the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any.

Section 3. Electronic Access Controls: Each Responsible Entity shall:

3.1 ~~For~~Implement electronic access control(s) for LERC, if any, ~~implement a LEAP~~ to permit only necessary ~~inbound and outbound bi-directional routable protocol access; and~~electronic access to low impact BES Cyber System(s).

3.2 Implement authentication for all Dial-up Connectivity, if any, that provides access to low impact BES Cyber Systems, per Cyber Asset capability.

Section 4. Cyber Security Incident Response: Each Responsible Entity shall have one or more Cyber Security Incident response plan(s), either by asset or group of assets, which shall include:

4.1 Identification, classification, and response to Cyber Security Incidents;

4.2 Determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity ~~Sector~~ Information Sharing and Analysis Center (~~ES~~E-ISAC), unless prohibited by law;

4.3 Identification of the roles and responsibilities for Cyber Security Incident response by groups or individuals;

4.4 Incident handling for Cyber Security Incidents;

4.5 Testing the Cyber Security Incident response plan(s) at least once every 36 calendar months by: (1) responding to an actual Reportable Cyber Security Incident; (2) using a drill or tabletop exercise of a Reportable Cyber Security Incident; or (3) using an operational exercise of a Reportable Cyber Security Incident; and

4.6 Updating the Cyber Security Incident response plan(s), if needed, within 180 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident.

~~CIP-003-6 –~~ Attachment 2

Examples of Evidence for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Section 1. Cyber Security Awareness: An example of evidence for Section 1 may include, but is not limited to, documentation that the reinforcement of cyber security practices occurred at least once every 15 calendar months. The evidence could be documentation through one or more of the following methods:

- Direct communications (for example, e-mails, memos, or computer-based training);
- Indirect communications (for example, posters, intranet, or brochures); or
- Management support and reinforcement (for example, presentations or meetings).

Section 2. Physical Security Controls: Examples of evidence for Section 2 may include, but are not limited to:

- Documentation of the selected access control(s) (e.g., card key, locks, perimeter controls), monitoring controls (e.g., alarm systems, human observation), or other operational, procedural, or technical physical security controls that control physical access to both:
  a. The asset, if any, or the locations of the low impact BES Cyber Systems within the asset; and
  b. The Cyber Asset specified by the Responsible Entity that provides electronic access controls implemented for Section 3.1, if any~~, containing a LEAP~~.

Section 3. Electronic Access Controls: Examples of evidence for Section 3 may include, but are not limited to:

1. Documentation, such as representative diagrams or lists of implemented electronic access controls (e.g., restricting IP addresses, ports, or services; authenticating users; air-gapping networks; terminating routable protocol sessions on a non-BES Cyber Asset; implementing unidirectional gateways) showing that ~~inbound and outbound connections~~ for ~~any LEAP(s) are~~LERC at each asset or group of assets containing low impact BES Cyber Systems, is confined ~~to~~ only ~~those~~to that access the Responsible Entity deems necessary ~~(e.g., by restricting IP addresses, ports, or services); and documentation~~; and

~~1.~~2. Documentation of authentication for Dial-up Connectivity (e.g., dial out only to a preprogrammed number to deliver data, dial-back modems, modems that must be remotely controlled by the control center or control room, or access control on the BES Cyber System).

Section 4. Cyber Security Incident Response: An example of evidence for Section 4 may include, but is not limited to, dated documentation, such as policies, procedures, or process documents of one or more Cyber Security Incident response plan(s) developed either by asset or group of assets that include the following processes:

1. to identify, classify, and respond to Cyber Security Incidents; to determine whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and for notifying the Electricity ~~Sector~~ Information Sharing and Analysis Center (~~ES~~E-ISAC);
2. to identify and document the roles and responsibilities for Cyber Security Incident response by groups or individuals (e.g., initiating, documenting, monitoring, reporting, etc.);
3. for incident handling of a Cyber Security Incident (e.g., containment, eradication, or recovery/incident resolution);
4. for testing the plan(s) along with the dated documentation that a test has been completed at least once every 36 calendar months; and
5. to update, as needed, Cyber Security Incident response plan(s) within 180 calendar days after completion of a test or actual Reportable Cyber Security Incident.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

In developing policies in compliance with Requirement R1, the number of policies and their content should be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization, or as components of specific programs. The Responsible Entity has the flexibility to develop a single comprehensive cyber security policy covering the required topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-~~6~~7, Requirement R1.

If a Responsible Entity has any high or medium impact BES Cyber Systems, the one or more cyber security policies must cover the nine subject matter areas required by CIP-003-~~6~~7, Requirement R1, Part 1.1. If a Responsible Entity has identified from CIP-002 any *assets containing low impact BES Cyber Systems*~~,~~, also referred to herein as ~~("~~BES assets~~"),~~ the one or more cyber security policies must cover the four subject matter areas required by Requirement R1, Part 1.2.

Responsible Entities that have multiple-impact rated BES Cyber Systems are not required to create separate cyber security policies for high, medium, or low impact BES Cyber Systems. The Responsible Entities have the flexibility to develop policies that cover all three impact ratings.

Implementation of the cyber security policy is not specifically included in CIP-003-~~6~~7, Requirement R1 as it is envisioned that the implementation of this policy is evidenced through successful implementation of CIP-003 through CIP-011. However, Responsible Entities are encouraged not to limit the scope of their cyber security policies to only those requirements in

NERC cyber security Reliability Standards, but to develop a holistic cyber security policy appropriate for its organization. Elements of a policy that extend beyond the scope of NERC's cyber security Reliability Standards will not be considered candidates for potential violations although they will help demonstrate the organization's internal culture of compliance and posture towards cyber security.

For Part 1.1, the Responsible Entity should consider the following for each of the required topics in its one or more cyber security policies for medium and high impact BES Cyber Systems, if any:

1.1.1 Personnel and training (CIP-004)

- Organization position on acceptable background investigations
- Identification of possible disciplinary action for violating this policy
- Account management

1.1.2 Electronic Security Perimeters (CIP-005) including Interactive Remote Access

- Organization stance on use of wireless networks
- Identification of acceptable authentication methods
- Identification of trusted and untrusted resources
- Monitoring and logging of ingress and egress at Electronic Access Points
- Maintaining up-to-date anti-malware software before initiating Interactive Remote Access
- Maintaining up-to-date patch levels for operating systems and applications used to initiate Interactive Remote Access
- Disabling VPN "split-tunneling" or "dual-homed" workstations before initiating Interactive Remote Access
- For vendors, contractors, or consultants: include language in contracts that requires adherence to the Responsible Entity's Interactive Remote Access controls

1.1.3 Physical security of BES Cyber Systems (CIP-006)

- Strategy for protecting Cyber Assets from unauthorized physical access
- Acceptable physical access control methods
- Monitoring and logging of physical ingress

1.1.4 System security management (CIP-007)

- Strategies for system hardening
- Acceptable methods of authentication and access control
- Password policies including length, complexity, enforcement, prevention of brute force attempts

- Monitoring and logging of BES Cyber Systems

1.1.5 Incident reporting and response planning (CIP-008)

- Recognition of Cyber Security Incidents
- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

1.1.6 Recovery plans for BES Cyber Systems (CIP-009)

- Availability of spare components
- Availability of system backups

1.1.7 Configuration change management and vulnerability assessments (CIP-010)

- Initiation of change requests
- Approval of changes
- Break-fix processes

1.1.8 Information protection (CIP-011)

- Information access control methods
- Notification of unauthorized information disclosure
- Information access on a need-to-know basis

1.1.9 Declaring and responding to CIP Exceptional Circumstances

- Processes to invoke special procedures in the event of a CIP Exceptional Circumstance
- Processes to allow for exceptions to policy that do not violate CIP requirements

Requirements relating to exceptions to a Responsible Entity's security policies were removed because it is a general management issue that is not within the scope of a reliability requirement. It is an internal policy requirement and not a reliability requirement. However, Responsible Entities are encouraged to continue this practice as a component of their cyber security policies.

In this and all subsequent required approvals in the NERC CIP Reliability Standards, the Responsible Entity may elect to use hardcopy or electronic approvals to the extent that there is sufficient evidence to ensure the authenticity of the approving party.

Requirement R2:

Using the list of assets containing low impact BES Cyber Systems from CIP-002, the intent of the requirement is for each Responsible Entity to create, document, and implement one or more cyber security plan(s) that addresses objective criteria for the protection of low impact BES Cyber Systems. The protections required by Requirement R2 reflect the level of risk that misuse or the unavailability of low impact BES Cyber Systems poses to the BES. The intent is that the required protections are part of a program that covers the low impact BES Cyber Systems

collectively either at an asset or site level (assets containing low impact BES Cyber Systems), but not at an individual device or system level.

There are four subject matter areas, as identified in Attachment 1, that must be covered by the cyber security plan: (1) cyber security awareness, (2) physical security controls, (3) electronic access controls for LERC and Dial-up Connectivity, and (4) Cyber Security Incident response.

Requirement R2, Attachment 1

As noted, Attachment 1 contains the sections that must be in the cyber security plan(s). The intent is to allow entities that have a combination of high, medium, and low impact BES Cyber Systems the flexibility to choose, if desired, to cover their low impact BES Cyber Systems (or any subset) under their programs used for the high or medium impact BES Cyber Systems rather than maintain two separate programs. Guidance for each of the four subject matter areas of Attachment 1 is provided below.

Requirement R2, Attachment 1, Section 1 – Cyber Security Awareness

The intent of the cyber security awareness program is for entities to reinforce good cyber security practices with their personnel at least once every 15 calendar months. The entity has the discretion to determine the topics to be addressed and the manner in which it will communicate these topics. As evidence of compliance, the Responsible Entity should be able to produce the awareness material that was delivered according to the delivery method(s) (e.g., posters, emails, or topics at staff meetings, etc.). The Responsible Entity is not required to maintain lists of recipients and track the reception of the awareness material by personnel.

Although the focus of the awareness is cyber security, it does not mean that only technology-related topics can be included in the program. Appropriate physical security topics (e.g., tailgating awareness and protection of badges for physical security, or “If you see something, say something” campaigns, etc.) are valid for cyber security awareness. The intent is to cover topics concerning any aspect of the protection of BES Cyber Systems.

Requirement R2, Attachment 1, Section 2 – Physical Security Controls

The Responsible Entity must document and implement methods to control physical access to (1) the asset or the locations of low impact BES Cyber Systems ~~at assets containing low impact BES~~ within the asset, and (2) Cyber ~~System~~Assets that implement the electronic access control(s) ~~and (2) LEAPs~~specified by the Responsible Entity in Section 3, if any. If ~~the LEAP is~~these Cyber Assets are located within the BES asset and ~~inherits~~inherit the same controls outlined in Section 2, this can be noted by the Responsible Entity in either its policies or cyber security plan(s) to avoid duplicate documentation of the same controls.

The Responsible Entity has the flexibility in the selection of the methods used to meet the objective to control physical access to the asset(s) containing low impact BES Cyber ~~Systems,~~System(s) or the low impact BES Cyber Systems themselves, ~~or LEAPs~~as well as physical protection of the electronic access control Cyber Assets specified by the Responsible Entity, if any. The Responsible Entity may use one or a combination of access controls, monitoring controls, or other operational, procedural, or technical physical security controls. Entities may use perimeter controls (e.g., fences with locked gates, guards, or site access policies, etc.) or more granular areas of physical access control in areas where low impact BES Cyber Systems are located, such as control rooms or control houses. User authorization programs and lists of

authorized users for physical access are not required although they are an option to meet the security objective.

The objective is to control the physical access based on need as determined by the Responsible Entity. The need can be documented at the policy level for access to the site or systems, including LEAPs.. The requirement does not obligate an entity to specify a need for each access or authorization of a user for access.

Monitoring as a physical security control can be used as a complement or an alternative to access control. Examples of monitoring controls include, but are not limited to: (1) alarm systems to detect motion or entry into a controlled area, or (2) human observation of a controlled area. Monitoring does not necessarily require logging and maintaining logs but could include monitoring that physical access has occurred or been attempted (e.g., door alarm, or human observation, etc.). The monitoring does not need to be per low impact BES Cyber System but should be at the appropriate level to meet the security objective.

Requirement R2, Attachment 1, Section 3 – Electronic Access Controls

Section 3 requires the establishment of boundary protectionselectronic access controls for *assets containing low impact BES Cyber Systems*, also referred to herein as ("BES assets") when the low impact BES Cyber Systems have bi-directional external routable protocol communication (LERC) or Dial-up Connectivity is present to devices external toor from the asset containing the low impact BES Cyber Systems.System(s). The establishment of boundary protectionselectronic access controls is intended to control communication either into the asset containing low impact BES Cyber System(s) or to the low impact BES Cyber System itself to reduce the risks associated with uncontrolled communication using routable protocols or Dial-up Connectivity. The term "electronic access control" is used in the general sense, i.e., to control access, and not in the specific technical sense requiring authentication, authorization, and auditing. The Responsible Entity is not required to establish LERC communication or a LEAP if there is no bi-directional routable protocol communication or In the case where there is no LERC or Dial-up Connectivity present. In the case where there is no external bi-directional routable protocol communication, the Responsible Entity can document the absence of such communication in its low impact cyber security plan(s).

When identifying electronic access controls, Responsible Entities are provided flexibility in the selection of the controls that meet their operational needs while meeting the security objective of allowing only necessary electronic access to low impact BES Cyber Systems.

In essence, Responsible Entities are to determine LERC or Dial-up Connectivity for their BES assets and then, if present, document and implement electronic access control(s).

Determining LERC

The defined terms LERC and LEAP are term Low Impact External Routable Communication (LERC) is used to avoid confusion with the similar terms term External Routable Connectivity (ERC) used for high and medium impact BES Cyber Systems (e.g., External Routable Connectivity (ERC) or as these terms are different concepts. The input to this requirement from CIP-002 is a list of assets containing low impact BES Cyber Systems, therefore LERC is an attribute of a BES asset and involves routable protocol communications to or from the BES asset (crossing the

asset boundary) without regard to connectivity to Cyber Assets within the BES asset. ERC on the other hand is an attribute of an individual high or medium impact BES Cyber System and is relative to an Electronic ~~Access Point (EAP)). To future-proof the standards, and in~~Security Perimeter (ESP).

With LERC being a BES asset level attribute, it is used as a higher level filter to exclude from further consideration those assets containing low impact BES Cyber Systems that have no routable protocol communications to them from outside the BES asset. Responsible Entities can then concentrate their electronic access control efforts on those BES assets that do have LERC. However, this also means that LERC can exist for a BES asset even if there is no routable protocol connectivity to any low impact BES Cyber System within the BES asset.

In order to avoid future technology issues, the ~~definitions~~LERC definition specifically ~~exclude "point-to-point~~excludes communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions between ~~Transmission station or substation~~non-Control Center BES assets containing low impact BES Cyber Systems~~,"~~, such as IEC 61850 messaging. This does not exclude Control Center to field communication but rather excludes the communication between the intelligent electronic devices ~~themselves.~~(e.g. relays) in the field. A Responsible Entity using this technology is not expected to implement ~~a LEAP~~the electronic access controls noted herein. This exception was included so as not to inhibit the functionality of the time-sensitive requirements related to this technology nor to preclude the use of such time-sensitive reliability enhancing functions if they use a routable protocol in the future.

Determining Asset Boundary

As LERC is a BES asset level attribute, it involves a determination by the Responsible Entity of a BES asset boundary for their assets containing low impact BES Cyber Systems. This boundary will vary by BES asset type (Control Center, substation, generation resource) and the specific configuration of the BES asset. The intent is for the Responsible Entity to define the BES asset boundary such that the low impact BES Cyber System(s) that are located at the BES asset are contained within the BES asset boundary. This is strictly for determining what constitutes the BES "asset" and for determining which routable protocol communications and networks are *internal* or *inside* or *local* to the BES asset and which are *external to or outside* the BES asset. This is not an Electronic Security Perimeter or Physical Security Perimeter as defined for medium and high impact BES Cyber Systems. For the asset containing low impact BES Cyber System(s), the BES asset boundary is synonymous to the concept of a "logical border" demarcation where routable protocol communication (e.g. LERC) enters and exits the BES asset containing the low impact BES Cyber System. Some examples of ways a Responsible Entity may determine BES asset boundaries are:

- For Control Centers
  - Designated areas (room(s) or floor(s)) if the Control Center is located within a larger building.
  - A building if in a dedicated building on a shared campus.

- The property/fence line if the Control Center is a dedicated facility on dedicated property.

- For substations, this could be the property/fence line or the control house.
- For generation resources:
  - Fossil/hydro generating facilities: This could be the property/fence line. If pumps or wells or other equipment that are part of the plant asset are outside the property line, then the BES asset boundary could expand to accommodate all that is considered part of the plant.
  - Solar farms: This could be the property line(s) or fence(s) surrounding all solar panels and interconnection facilities.
  - Wind farms: This could be the collection of individual turbines plus the equipment needed for interconnection.
  - Cogeneration facilities: This could be the identified portion of the larger plant that performs generation.

Determining Electronic Access Controls

Once a Responsible Entity has determined that LERC exists at the BES asset boundary, the Responsible Entity documents and implements its chosen electronic access control(s). The control(s) must allow only "necessary" access as determined by the Responsible Entity and they need to be able to explain the reasons for the electronic access permitted with their electronic access controls. The reasoning for the "necessary" access controls can be documented within the Responsible Entity's cyber security plan(s) or other policies or procedures associated with the electronic access controls.

Concept Diagrams

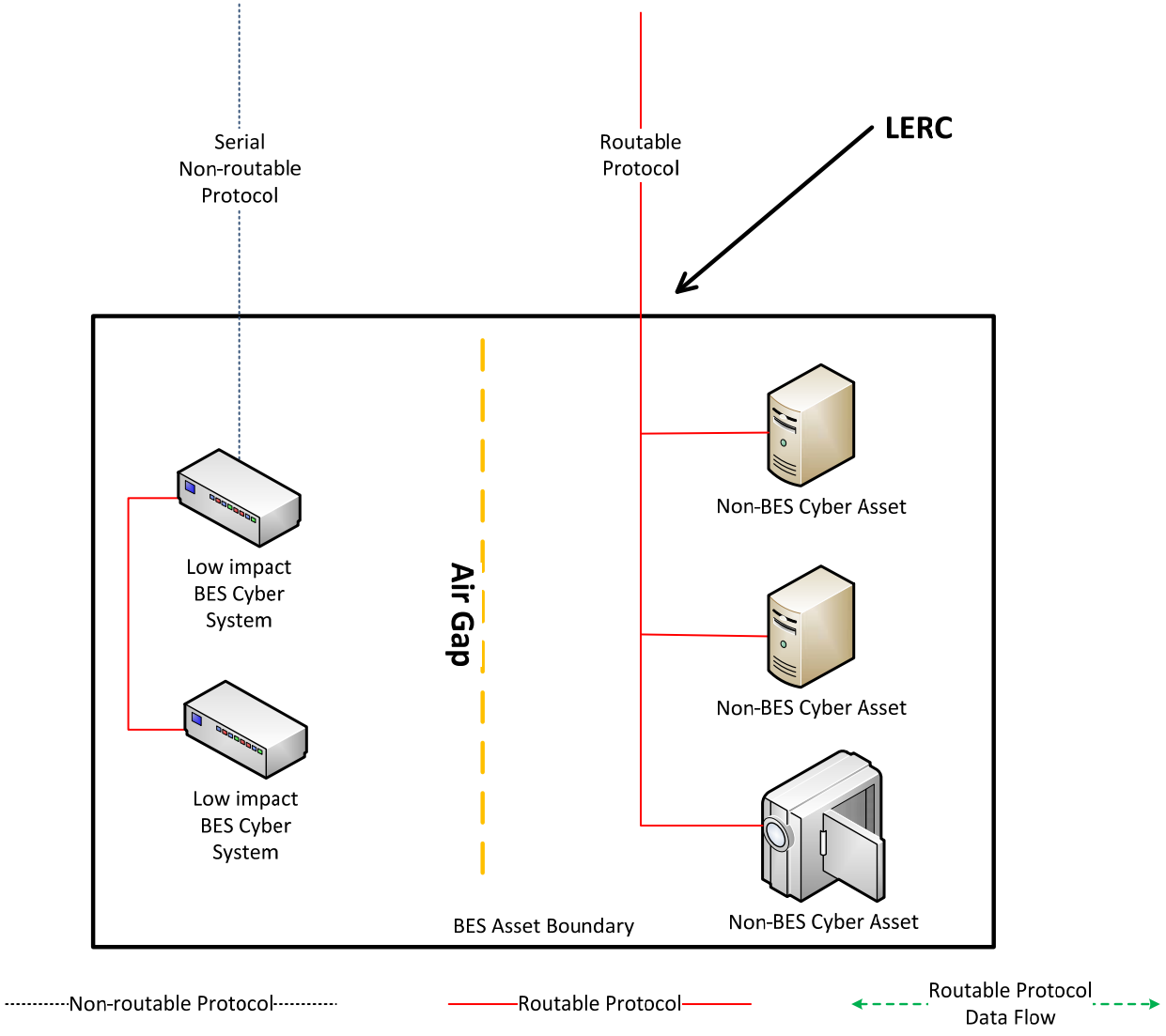
The diagrams on the following pages are provided as examples to illustrate various electronic access controls at a conceptual level. Regardless of the concepts or configurations chosen by the Responsible Entity, the security objective of permitting only necessary access to low impact BES Cyber Systems must be met when there is LERC to a BES asset.

NOTE:

- This is not an exhaustive list of applicable concepts.
- LERC is present in each diagram.
- The same legend is used in each diagram; however, the diagram may not contain all of the articles represented in the legend.
- The term "BES Asset Boundary" is capitalized in the diagrams but it is not a defined term.

LERC Reference Model 1 – Physical Isolation

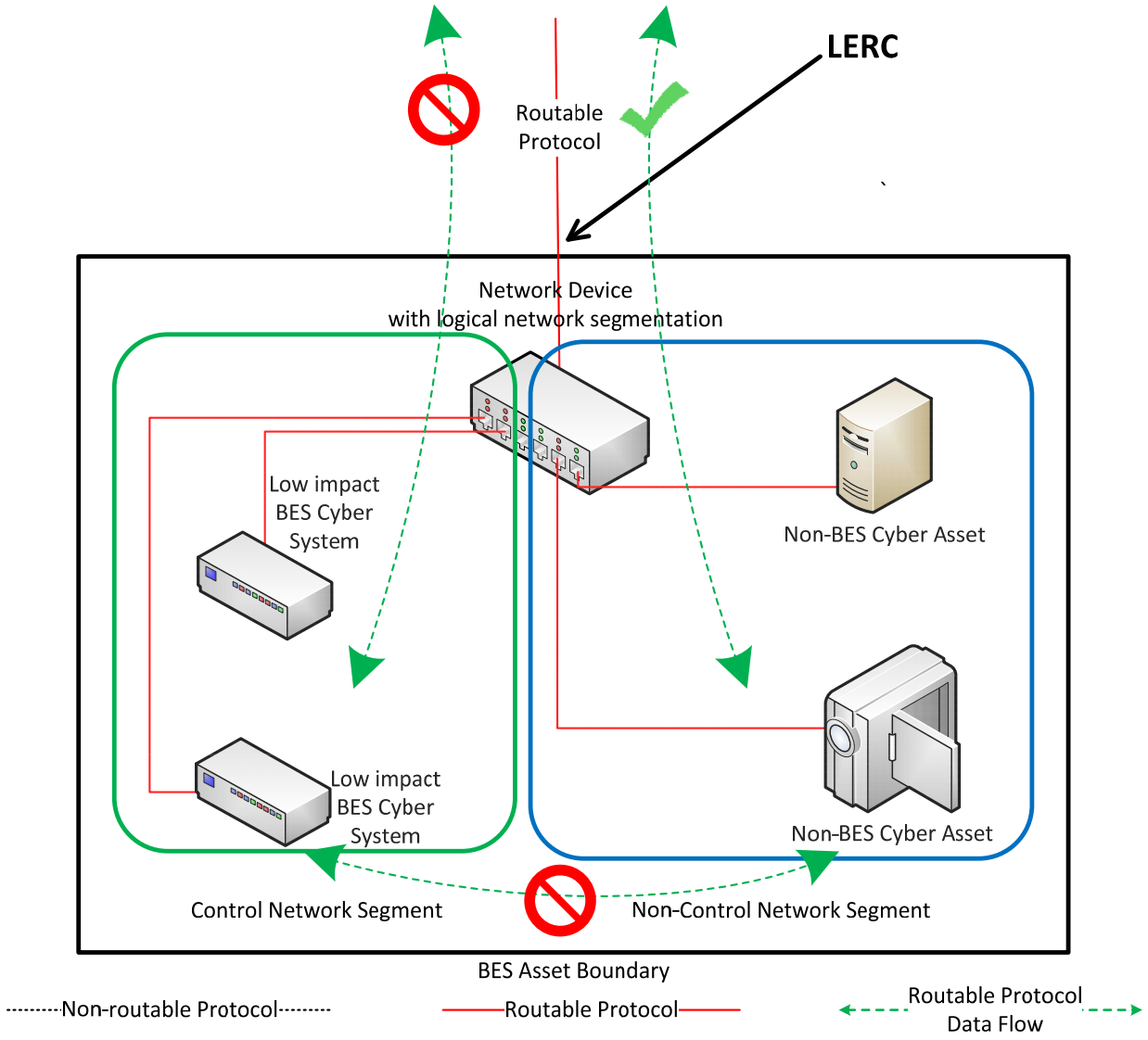
The Responsible Entity may choose to physically isolate the low impact BES Cyber System(s) from the LERC. This control is commonly referred to as an 'air gap'. The serial non-routable protocol connection and the routable protocol LERC are completely isolated from each other. There is no equipment shared with the low impact BES Cyber System(s).



Reference Model 1

LERC Reference Model 2 – Logical Isolation

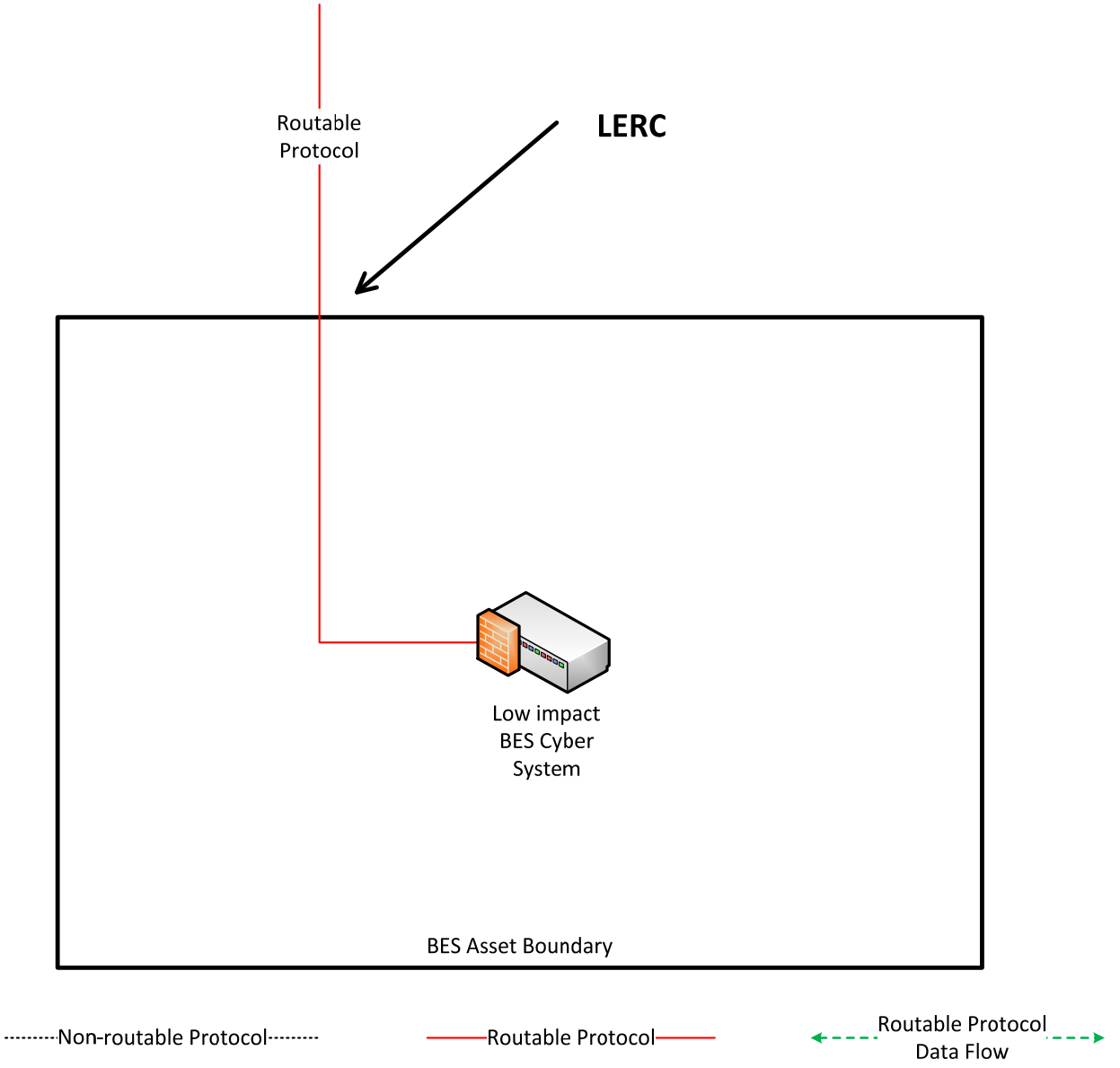
The Responsible Entity may choose to logically isolate the low impact BES Cyber System(s) from the LERC. The low impact BES Cyber System(s) is on an isolated network segment with logical controls preventing routable protocol communication into or out of the network containing the low impact BES Cyber System(s).



Reference Model 2

LERC Reference Model 3 – Host-based Inbound & Outbound Access Permissions

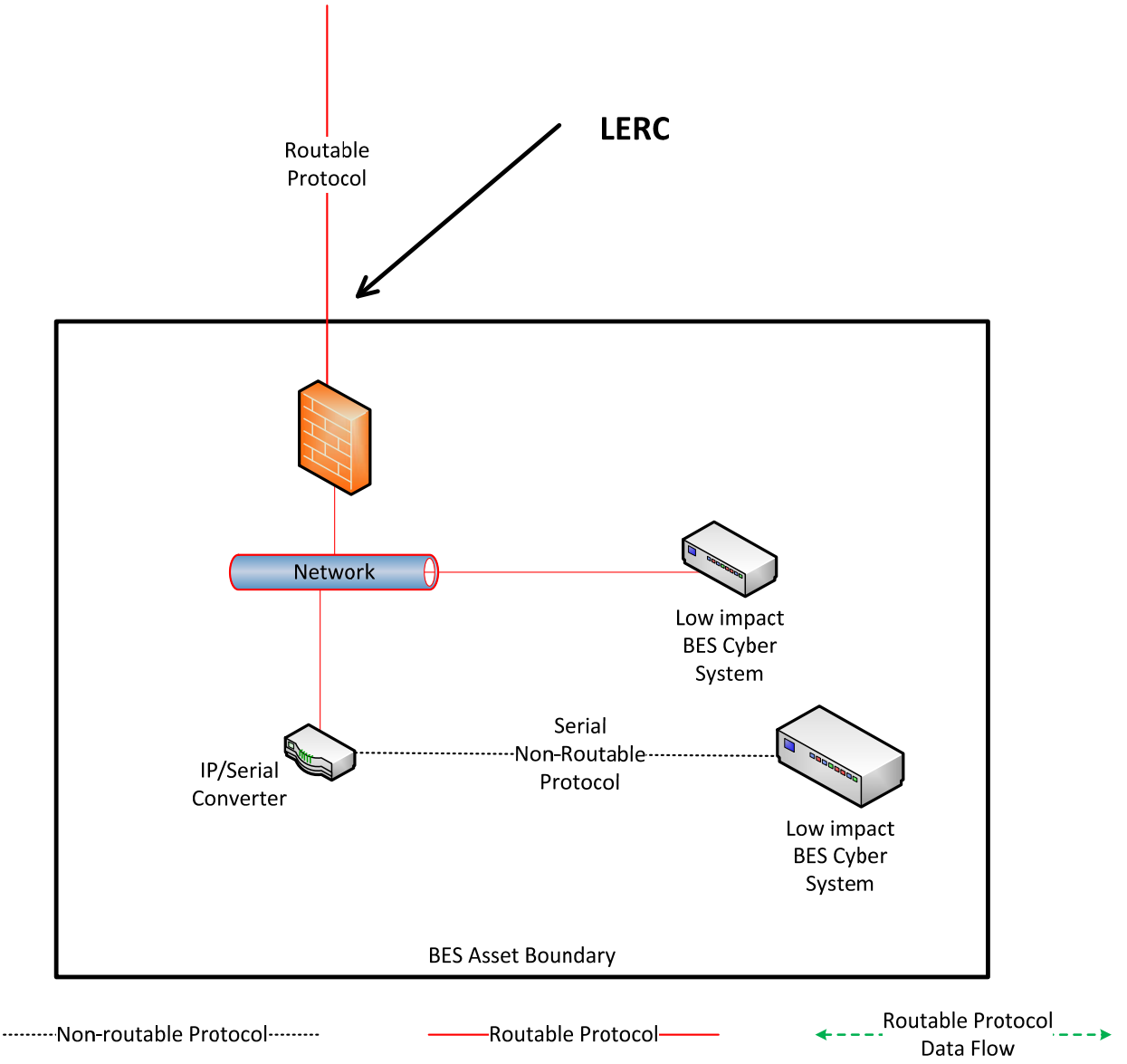
The Responsible Entity may choose to utilize a host-based firewall technology on the low impact BES Cyber System(s) that manages electronic access permission so that only necessary inbound and outbound routable protocol access is allowed to the low impact BES Cyber System(s).



Reference Model 3

LERC Reference Model 4 – Network-based Inbound & Outbound Access Permissions

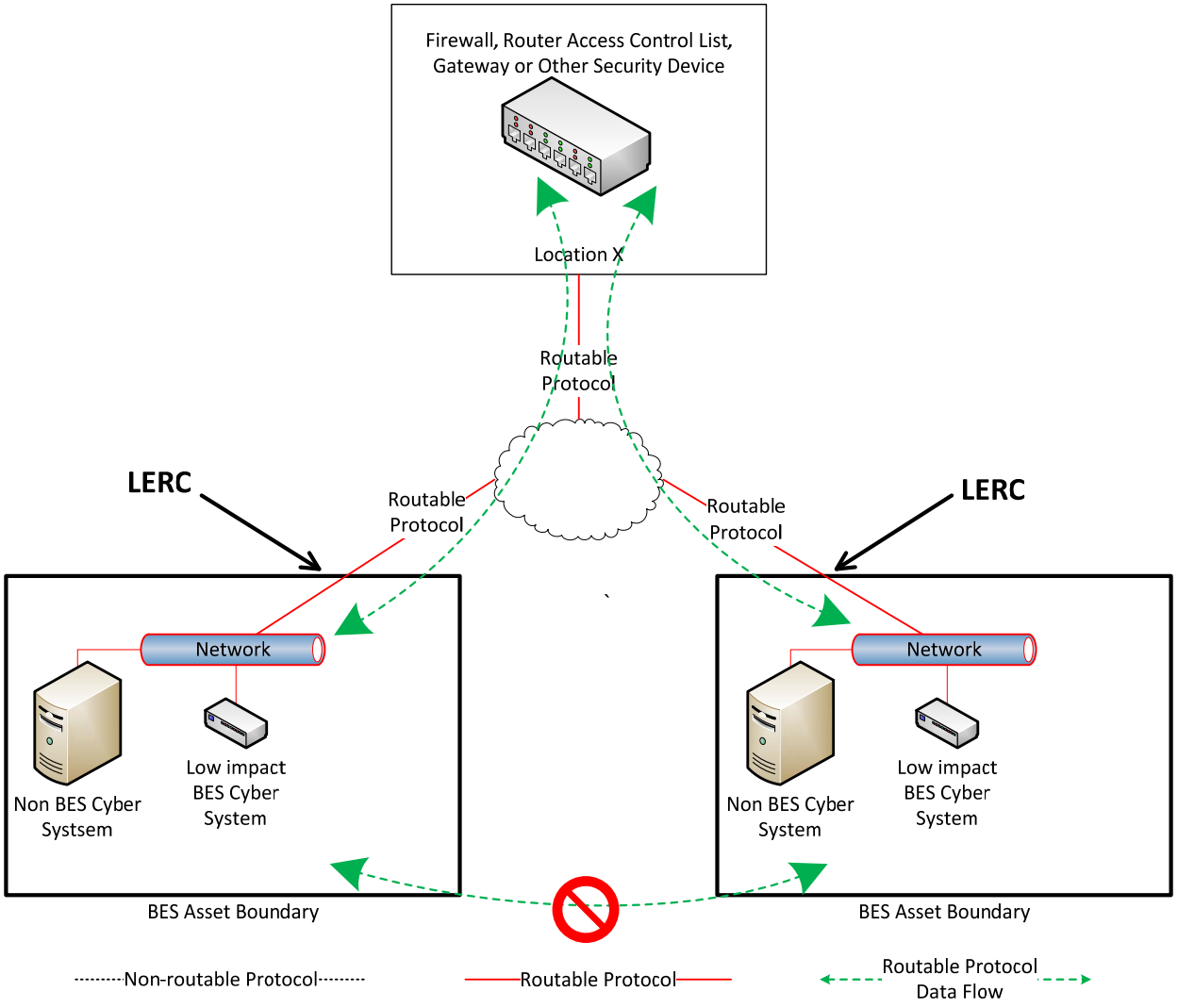
The Responsible Entity may choose to utilize a security device that permits only necessary access to the low impact BES Cyber System(s) within the BES asset. In this example, two low impact BES Cyber Systems are accessed over the LERC as the IP/Serial converter is continuing the same communications session from device(s) outside the BES asset boundary to the low impact BES Cyber Systems. The security device provides the electronic access controls to permit only necessary inbound and outbound routable protocol access to the low impact BES Cyber Systems.



Reference Model 4

LERC Reference Model 5 – Centralized Network-based Inbound & Outbound Access Permissions

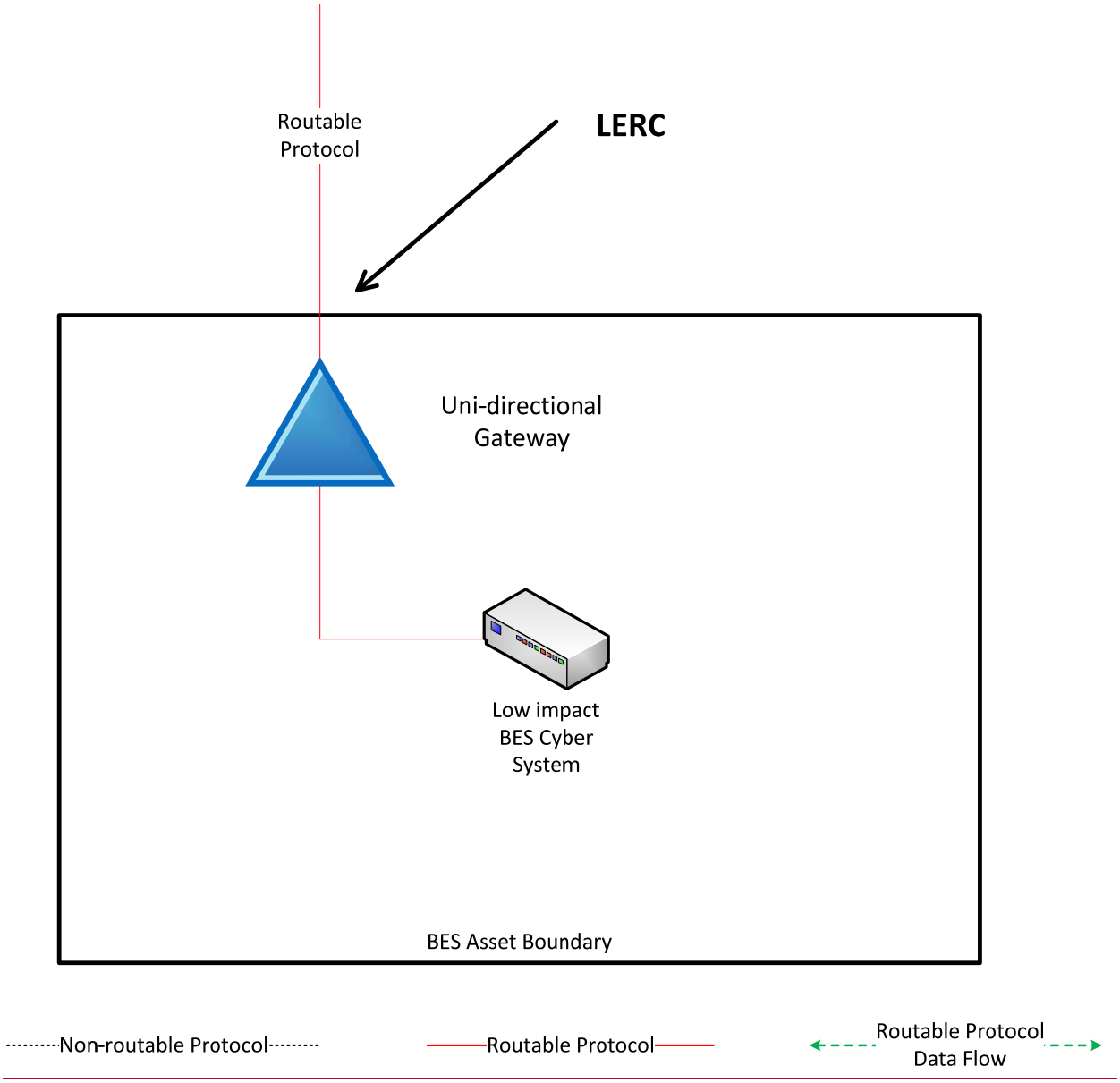
The Responsible Entity may choose to utilize a security device at a centralized location that may or may not be another BES asset. The electronic access control(s) do not necessarily have to reside inside the asset containing the low impact BES Cyber System(s). A security device is in place at "Location X" to act as the electronic access control and permit only necessary inbound and outbound routable protocol access to the low impact BES Cyber System(s). Care should be taken that electronic access to or between each BES asset is through the electronic access controls at the centralized location.



Reference Model 5

LERC Reference Model 6 – Uni-directional Gateway

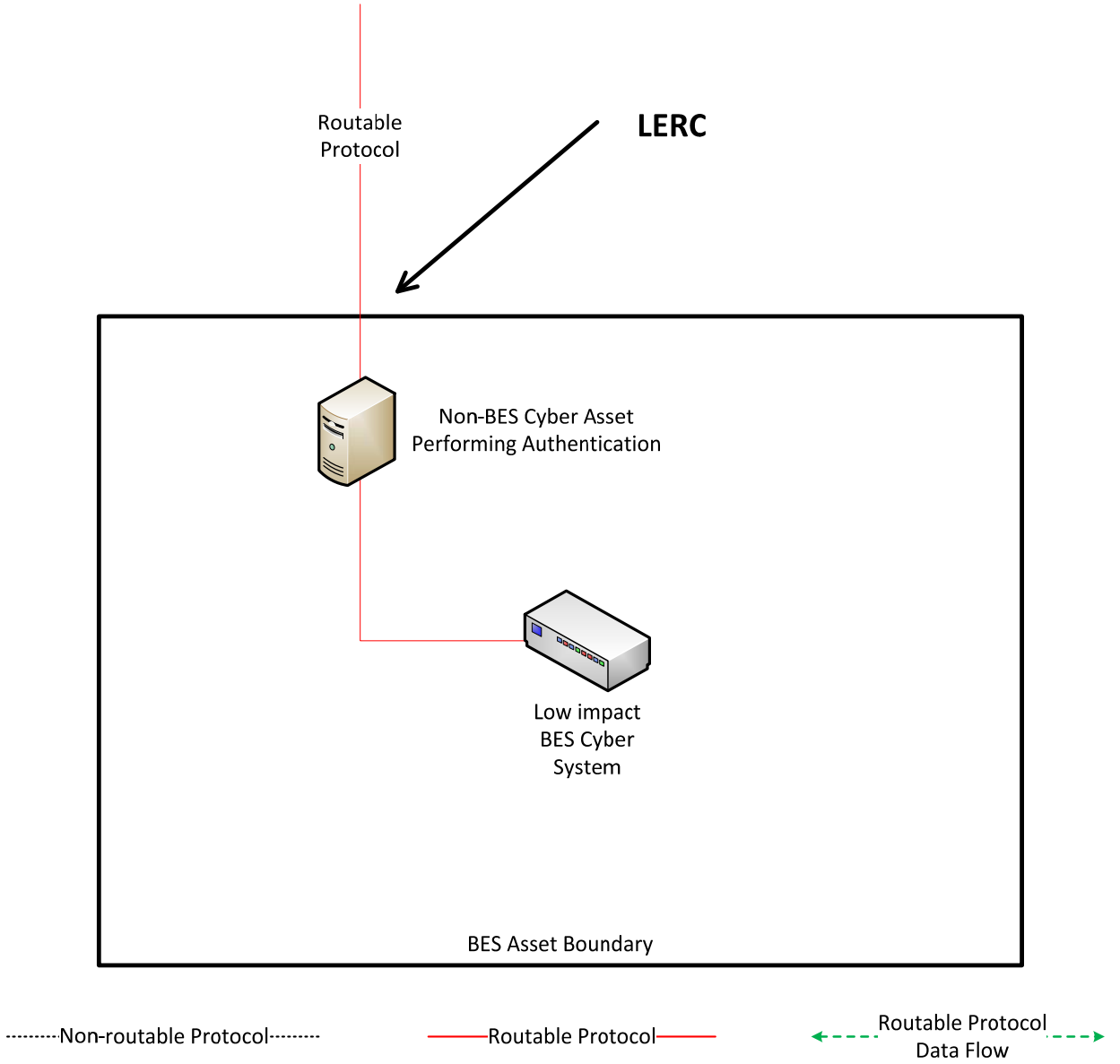
The Responsible Entity may choose to utilize a uni-directional gateway as the electronic access control. The low impact BES Cyber System(s) is not accessible (data cannot flow into the low impact BES Cyber System) from the LERC due to the implementation of a "one-way" (uni-directional) path for data to flow across the BES asset boundary.



Reference Model 6

LERC Reference Model 7 – User Authentication

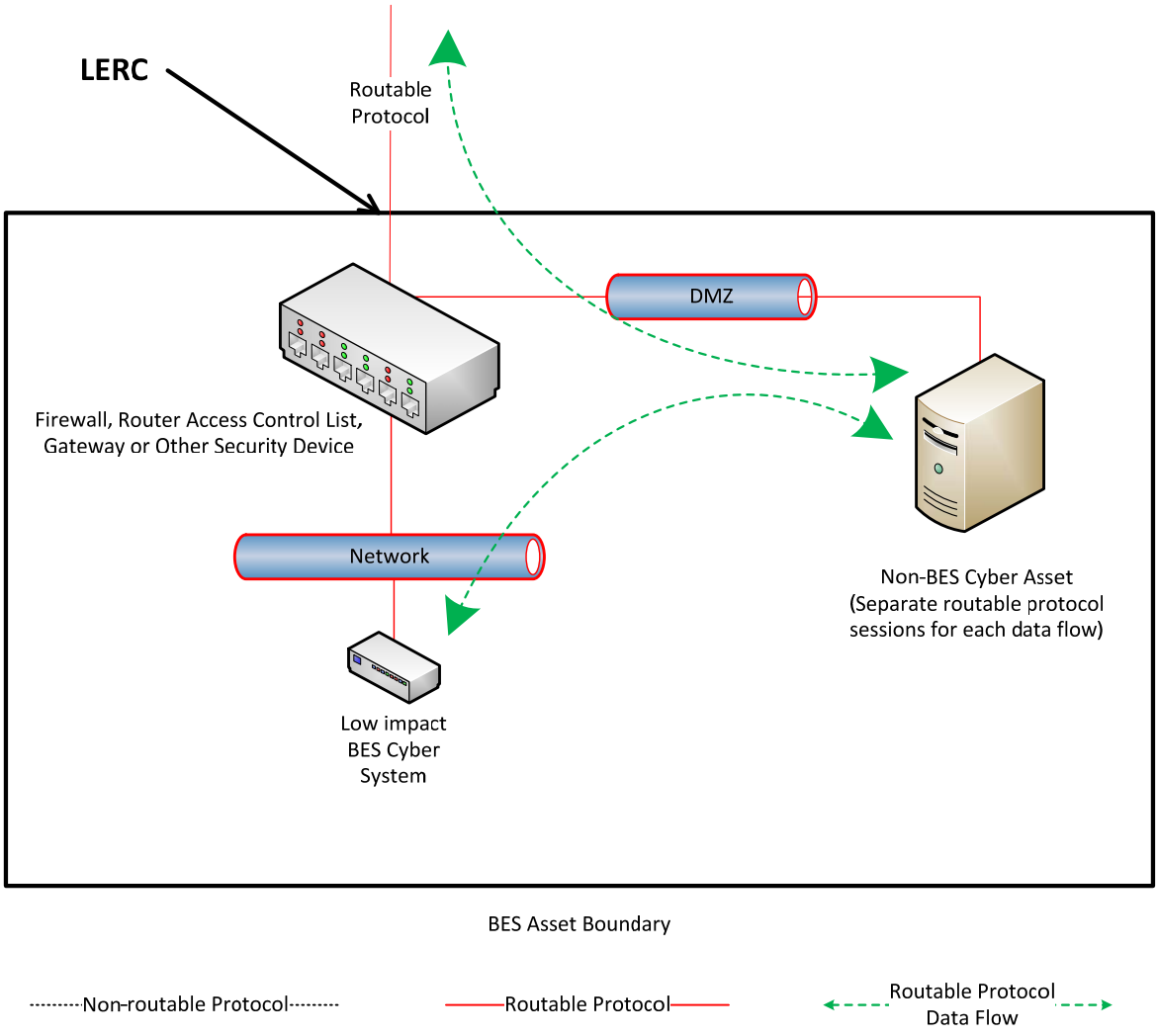
The Responsible Entity may choose to utilize a non-BES Cyber Asset between the network outside the BES asset boundary and the low impact BES Cyber System to perform user authentication for interactive access. The non-BES Cyber Asset would require authentication before establishing a new connection to the low impact BES Cyber System. The electronic access control depicted in this reference model may not meet the security objective for controlling device-to-device communication across the LERC depending on the specific system configuration in place.



Reference Model 7

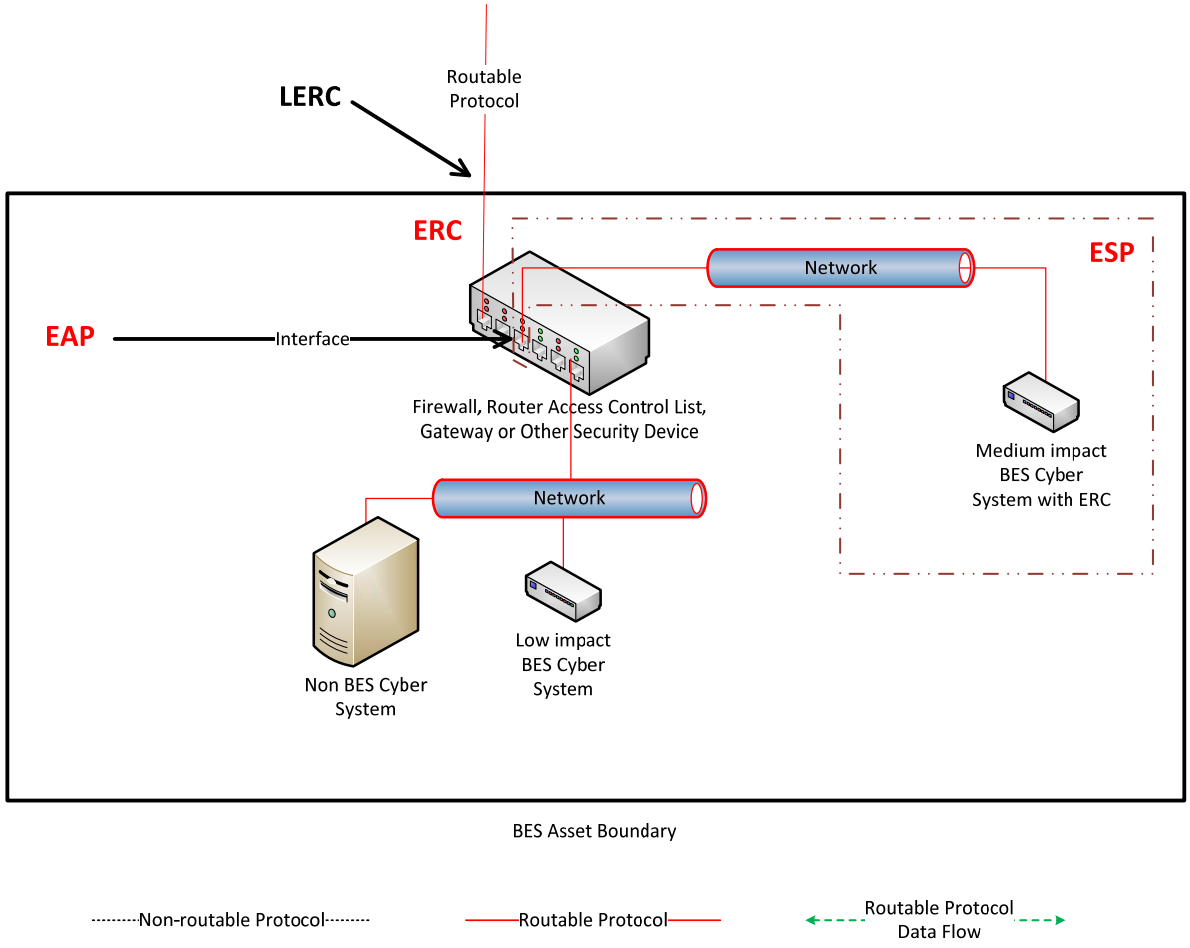
LERC Reference Model 8 – Session Termination

The Responsible Entity may choose to terminate routable protocol application sessions at a non-BES Cyber Asset inside the asset containing the low impact BES Cyber System(s) such that a separate application session is established to the low impact BES Cyber System(s) from the non-BES Cyber Asset (the routable session from outside the BES asset). The Responsible Entity may choose to authenticate access at a non-BES Cyber Asset either outside BES asset boundary or inside the asset containing the low impact BES Cyber System(s) such that unauthenticated access to the low impact BES Cyber System(s) is prohibited. The non-BES Cyber Asset sits on a demilitarized zone (DMZ) between the network outside the BES asset boundary and the low impact BES Cyber System(s). The non-BES Cyber Asset in the DMZ terminates the routable protocol session and establishes a new session to the low impact BES Cyber System(s). Additionally, a security device permits traffic from the network outside the BES asset boundary to flow only to and from the non-BES Cyber Asset in the DMZ (the routable session to the low impact BES Cyber System).



LERC Reference Model 9 – LERC and ERC

There is both LERC and ERC present in this reference model because there is at least one medium impact BES Cyber System and one low impact BES Cyber System within the BES asset. The Responsible Entity may choose to leverage an interface on the medium impact Electronic Access Control or Monitoring Systems (EACMS) device to provide electronic access controls for the LERC. The EACMS is therefore performing multiple functions – as a medium impact EACMS and as implementing low impact electronic access controls.



Reference Model 9

When determining whether there is LERC to the low impact BES Cyber System, the definition uses the phrases "direct user-initiated interactive access or a direct device-to-device connection to a low impact BES Cyber System(s) from a Cyber Asset outside the asset containing those low impact BES Cyber System(s) via a bi-directional routable protocol connection." The intent of "direct" in the definition is to indicate LERC exists if a person is sitting at another device outside of the asset containing the low impact BES Cyber System, and the person can connect to logon, configure, read, or interact, etc. with the low impact BES Cyber System using a bi-directional routable protocol within a single end-to-end protocol session even if there is a serial-to-routable protocol conversion. The reverse case would also be LERC, in which the individual sits at the low impact BES Cyber System and connects to a device outside the asset containing low impact BES Cyber Systems using a single end-to-end bi-directional routable protocol session. Additionally, for "device-to-device connection," LERC exists if the Responsible Entity has devices outside of the asset containing the low impact BES Cyber System sending or receiving bi-directional routable communication to or from the low impact BES Cyber System.

When identifying a LEAP, Responsible Entities are provided flexibility in the selection of the interface on a Cyber Asset that controls the LERC. Examples include, but are not limited to, the internal (facing the low impact BES Cyber Systems) interface on an external or host-based firewall, the internal interface on a router that has implemented an access control list (ACL), or other security device. The entity also has flexibility with respect to the location of the LEAP. LEAPs are not required to reside at the asset containing the low impact BES Cyber Systems. Furthermore, the entity is not required to establish a unique physical LEAP per asset containing low impact BES Cyber Systems. Responsible Entities can have a single Cyber Asset containing multiple LEAPs that controls the LERC for more than one asset containing low impact BES Cyber Systems. Locating the Cyber Asset with multiple LEAPs at an external location with multiple assets containing low impact BES Cyber Systems "behind" it, however, should not allow uncontrolled access to assets containing low impact BES Cyber Systems sharing a Cyber Asset containing the LEAP(s).

In Reference Model 4, the communication flows through an IP/Serial converter. LERC is correctly identified in this Reference Model because the IP/Serial converter in this instance is doing nothing more than extending the communication between the low impact BES Cyber System and the Cyber Asset outside the asset containing the low impact BES Cyber System. In contrast, Reference Model 6 has placed a Cyber Asset that performs a complete break or interruption that does not allow the user or device data flow to directly communicate with the low impact BES Cyber System. The Cyber Asset in Reference Model 6 is preventing extending access to the low impact BES Cyber System from the Cyber Asset outside the asset containing the low impact BES Cyber System. The intent is that if the IP/Serial converter that is deployed only does a "pass-through" of the data flow communication, then that "pass-through" data flow communication is LERC and a LEAP is required. However, if that IP/Serial converter performs some type of authentication in the data flow at the asset containing the low impact BES Cyber System before the communication can be sent to the low impact BES Cyber System, then that type of IP/Serial converter implementation is not LERC.

~~A Cyber Asset that contains interface(s) that only perform the function of a LEAP does not meet the definition of Electronic Access Control or Monitoring System (EACMS) associated with medium or high impact BES Cyber Systems and is not subject to the requirements applicable to an EACMS. However, a Cyber Asset may contain some interfaces that function as a LEAP and other interfaces that function as an EAP for high or medium impact BES Cyber Systems. In this case, the Cyber Asset would also be subject to the requirements applicable to the EACMS associated with the medium or high impact BES Cyber Systems.~~

~~Examples of sufficient access controls may include:~~

- ~~Any LERC for the asset passes through a LEAP with explicit inbound and outbound access permissions defined, or equivalent method by which both inbound and outbound connections are confined to only those that the Responsible Entity deems necessary (e.g., IP addresses, ports, or services).~~
- ~~As shown in Reference Model 1 below, the low impact BES Cyber System has a host-based firewall that is controlling the inbound and outbound access. In this model, it is also possible that the host-based firewall could be on a non-BES Cyber Asset. The intent is that the host-based firewall controls the inbound and outbound access between the low impact BES Cyber System and the Cyber Asset in the business network.~~
- ~~As shown in Reference Model 5 below, a non-BES Cyber Asset has been placed between the low impact BES Cyber System on the substation network and the Cyber Asset in the business network. The expectation is that the non-BES Cyber Asset has provided a "protocol break" so that access to the low impact BES Cyber System is only from the non-BES Cyber Asset that is located within the asset containing the low impact BES Cyber System.~~

Dial-up Connectivity

Dial-up Connectivity to a low impact BES Cyber System is set to dial out only (no auto-answer) to a preprogrammed number to deliver data. Incoming Dial-up Connectivity is to a dialback modem, a modem that must be remotely controlled by the control center or control room, has some form of access control, or the low impact BES Cyber System has access control.

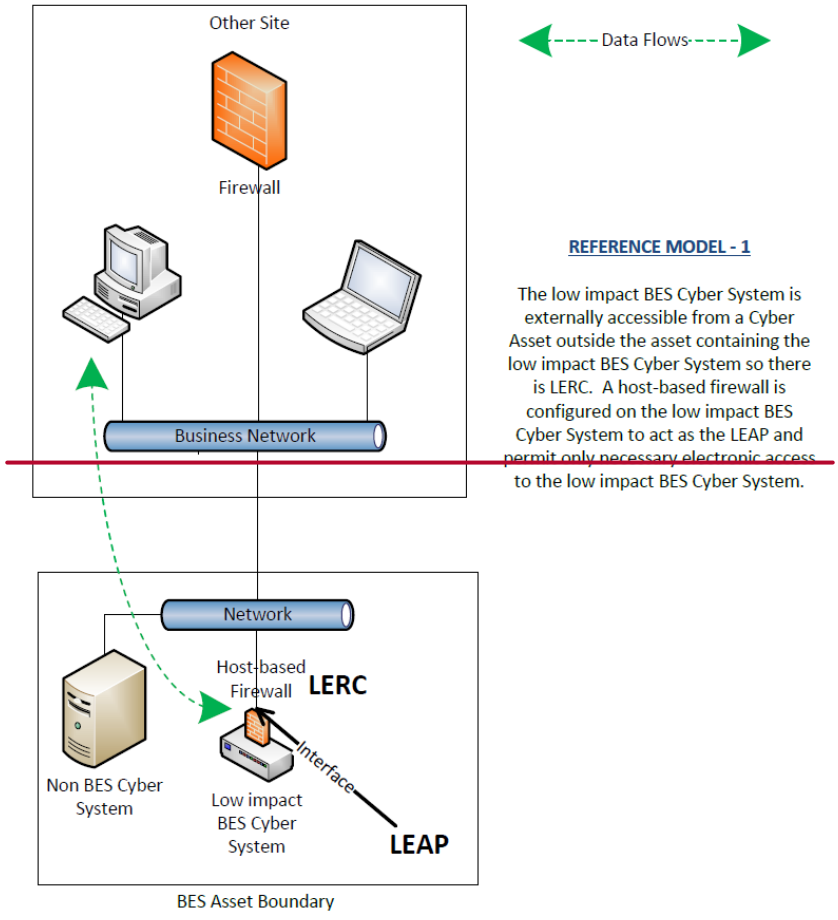
Insufficient Access Controls

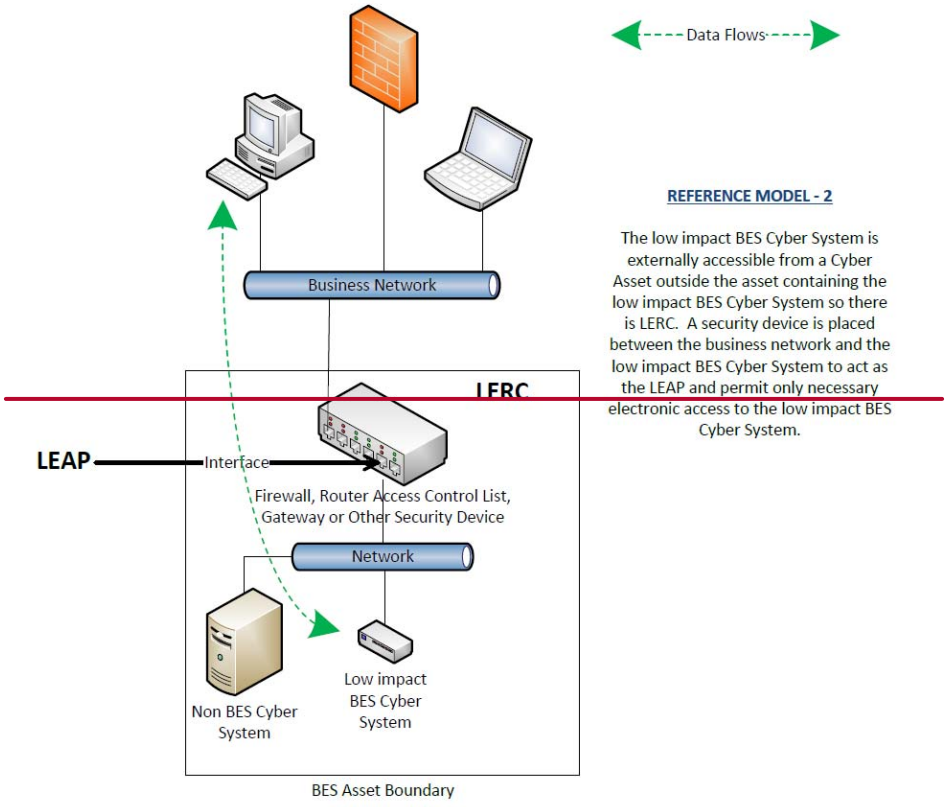
Some examples of situations that would lack sufficient access controls to meet the intent of this requirement include:

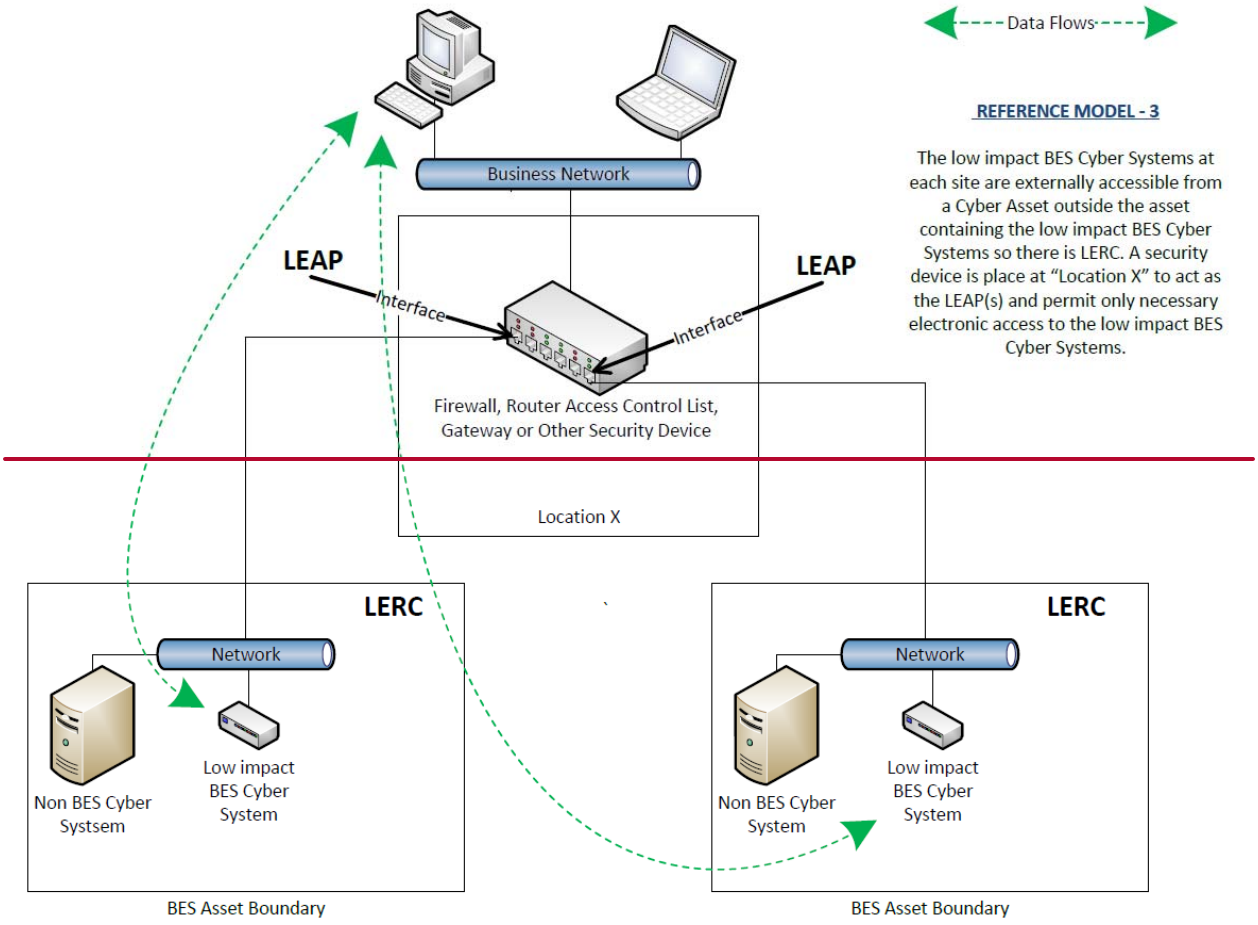
- An asset has Dial-up Connectivity and a low impact BES Cyber System is reachable via an auto-answer modem that connects any caller to the Cyber Asset that has a default password. There is no practical access control in this instance.
- An asset has LERC due to a BES Cyber System within it having a wireless card on a public carrier that allows the BES Cyber System to be reachable via a public IP address. In essence, low impact BES Cyber Systems should not be accessible from the Internet and search engines such as Shodan.
- ~~In Reference Model 5, using just dual~~Dual-homing or multiple-network interface cards without disabling IP forwarding in the non-BES Cyber Asset within the DMZ to provide

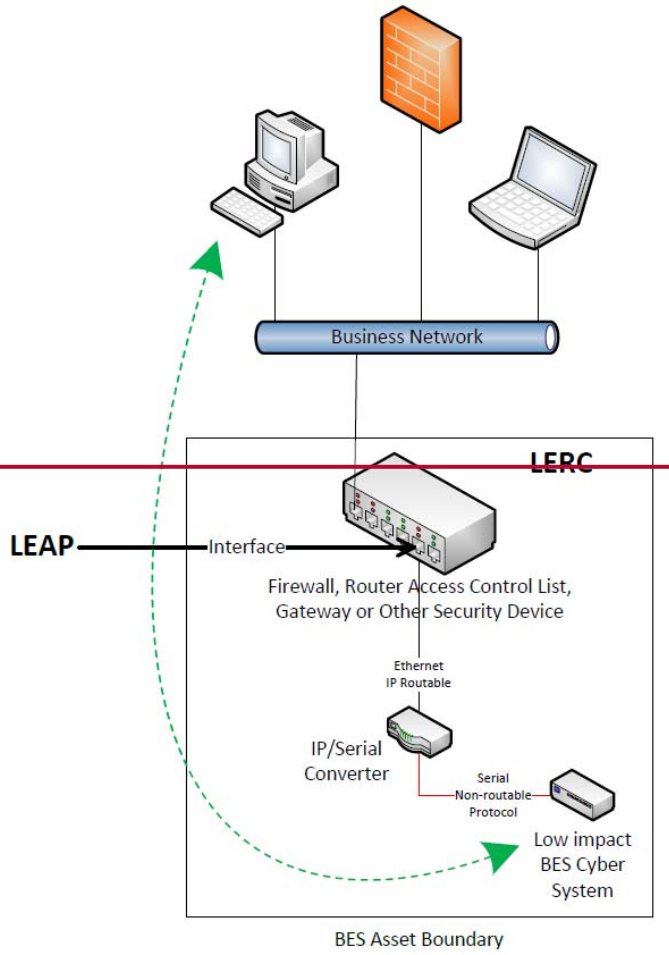
separation between the low impact BES Cyber System(s) and the ~~business~~external network would not meet the intent of "controlling" inbound and outbound electronic access assuming there was no other host-based firewall or other security ~~device~~devices on ~~that~~the non-BES Cyber Asset.

~~The following diagrams provide reference examples intended to illustrate how to determine whether there is LERC and for implementing a LEAP. While these diagrams identify several possible configurations, Responsible Entities may have additional configurations not identified below.~~




Data Flows
REFERENCE MODEL - 2
The low impact BES Cyber System is externally accessible from a Cyber Asset outside the asset containing the low impact BES Cyber System so there is LERC. A security device is placed between the business network and the low impact BES Cyber System to act as the LEAP and permit only necessary electronic access to the low impact BES Cyber System.
Business Network
LERC
LEAP
Interface
Firewall, Router Access Control List, Gateway or Other Security Device
Network
Non BES Cyber System
Low impact BES Cyber System
BES Asset Boundary

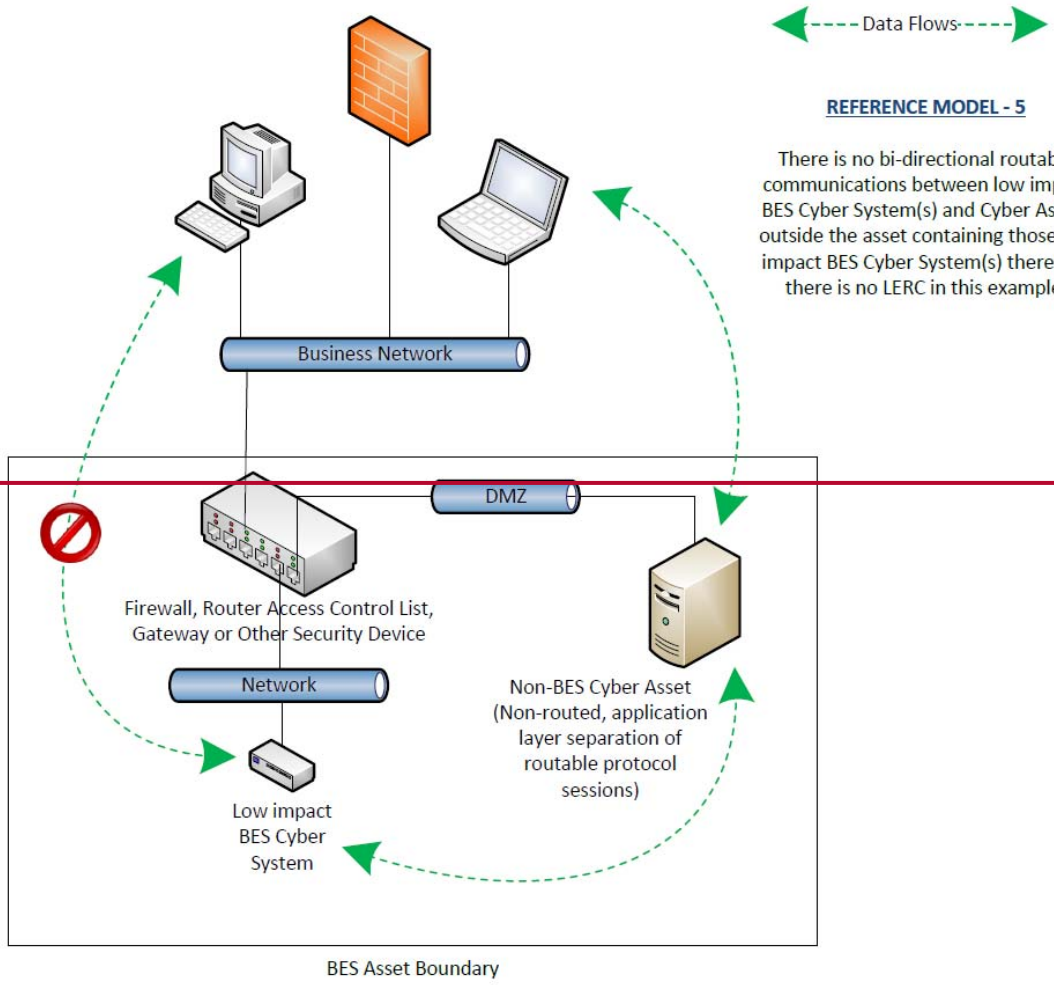

Data Flows
REFERENCE MODEL - 3
The low impact BES Cyber Systems at each site are externally accessible from a Cyber Asset outside the asset containing the low impact BES Cyber Systems so there is LERC. A security device is place at "Location X" to act as the LEAP(s) and permit only necessary electronic access to the low impact BES Cyber Systems.
Business Network
LEAP
Interface
LEAP
Interface
Firewall, Router Access Control List, Gateway or Other Security Device
Location X
LERC
Network
Non BES Cyber Systsem
Low impact BES Cyber System
BES Asset Boundary
LERC
Network
Non BES Cyber System
Low impact BES Cyber System
BES Asset Boundary

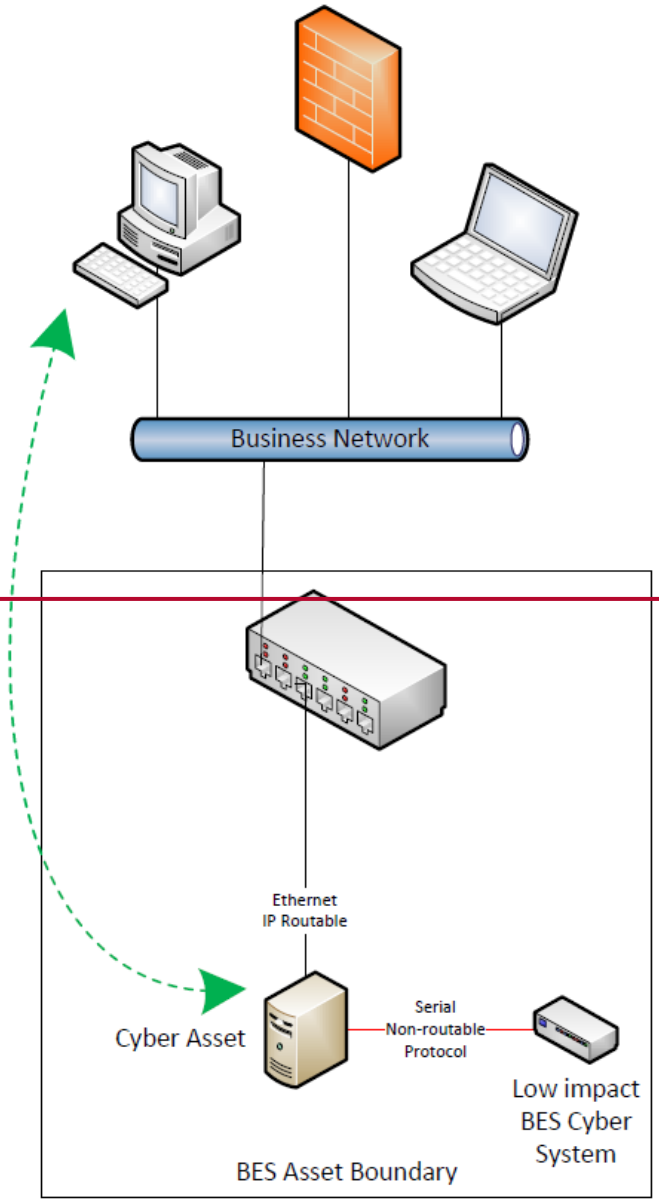


Data Flows

REFERENCE MODEL - 4

The low impact BES Cyber System is externally accessible from a Cyber Asset outside the asset containing the low impact BES Cyber System. There is LERC because the IP/Serial converter is extending the communication between the business network Cyber Asset and the low impact BES Cyber System is directly addressable from outside the asset. A security device is placed between the business network and the low impact BES Cyber System to permit only necessary electronic access to the low impact BES Cyber System.

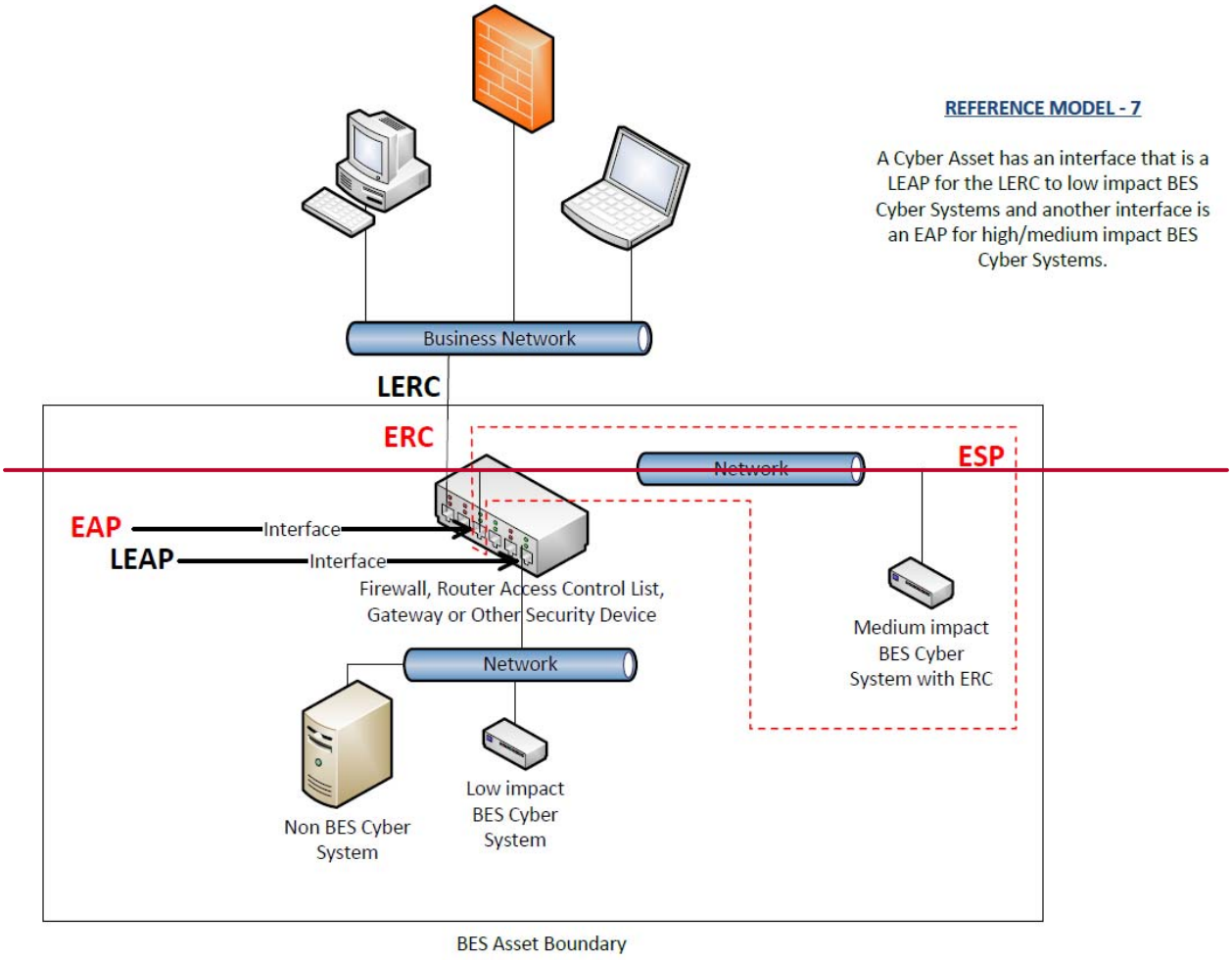

Data Flows
REFERENCE MODEL - 5
There is no bi-directional routable communications between low impact BES Cyber System(s) and Cyber Assets outside the asset containing those low impact BES Cyber System(s) therefore there is no LERC in this example.
Business Network
DMZ
Firewall, Router Access Control List, Gateway or Other Security Device
Network
Non-BES Cyber Asset (Non-routed, application layer separation of routable protocol sessions)
Low impact BES Cyber System
BES Asset Boundary



Data Flows

REFERENCE MODEL - 6

In this example, a Cyber Asset stops the direct access to the low impact BES Cyber System. There is a layer 7 application layer break or the Cyber Asset requires authentication and then establishes a new connection to the low impact BES Cyber System. There is no LERC in this example.



Requirement R2, Attachment 1, Section 4 – Cyber Security Incident Response

The entity should have one or more documented Cyber Security Incident response plan(s) that include each of the topics listed in Section 4. If, in the normal course of business, suspicious activities are noted at an asset containing low impact BES Cyber System(s), the intent is for the entity to implement a Cyber Security Incident response plan that will guide the entity in responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Entities are provided the flexibility to develop their Attachment 1, Section 4 Cyber Security Incident response plan(s) by asset or group of assets. The plans do not need to be on a per asset site or per low impact BES Cyber System basis. Entities can choose to use a single enterprise-wide plan to fulfill the obligations for low impact BES Cyber Systems.

The plan(s) must be tested once every 36 months. This is not an exercise per low impact BES Cyber Asset or per type of BES Cyber Asset but rather is an exercise of each incident response plan the entity created to meet this requirement. An actual Reportable Cyber Security Incident counts as an exercise as do other forms of tabletop exercises or drills. NERC-led exercises such as GridEx participation would also count as an exercise provided the entity's response plan is followed. The intent of the requirement is for entities to keep the Cyber Security Incident

response plan(s) current, which includes updating the plan(s), if needed, within 180 days following a test or an actual incident.

For low impact BES Cyber Systems, the only portion of the definition of Cyber Security Incident that would apply is, "A malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of a BES Cyber System." The other portion of that definition is not to be used to require ESPs and PSPs for low impact BES Cyber Systems.

Requirement R3:

The intent of CIP-003-~~6~~7, Requirement R3 is effectively unchanged since prior versions of the standard. The specific description of the CIP Senior Manager has now been included as a defined term rather than clarified in the Reliability Standard itself to prevent any unnecessary cross-reference to this standard. It is expected that the CIP Senior Manager will play a key role in ensuring proper strategic planning, executive/board-level awareness, and overall program governance.

Requirement R4:

As indicated in the rationale for CIP-003-~~6~~7, Requirement R4, this requirement is intended to demonstrate a clear line of authority and ownership for security matters. The intent of the SDT was not to impose any particular organizational structure, but, rather, the intent is to afford the Responsible Entity significant flexibility to adapt this requirement to its existing organizational structure. A Responsible Entity may satisfy this requirement through a single delegation document or through multiple delegation documents. The Responsible Entity can make use of the delegation of the delegation authority itself to increase the flexibility in how this applies to its organization. In such a case, delegations may exist in numerous documentation records as long as the collection of these documentation records shows a clear line of authority back to the CIP Senior Manager. In addition, the CIP Senior Manager could also choose not to delegate any authority and meet this requirement without such delegation documentation.

The Responsible Entity must keep its documentation of the CIP Senior Manager and any delegations up-to-date. This is to ensure that individuals do not assume any undocumented authority. However, delegations do not have to be re-instated if the individual who delegated the task changes roles or the individual is replaced. For instance, assume that John Doe is named the CIP Senior Manager and he delegates a specific task to the Substation Maintenance Manager. If John Doe is replaced as the CIP Senior Manager, the CIP Senior Manager documentation must be updated within the specified timeframe, but the existing delegation to the Substation Maintenance Manager remains in effect as approved by the previous CIP Senior Manager, John Doe.

Rationale:

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

Rationale for Requirement R1:

One or more security policies enable effective implementation of the requirements of the cyber security Reliability Standards. The purpose of policies is to provide a management and governance foundation for all requirements that apply to a Responsible Entity's BES Cyber

Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the requirements.

Annual review and approval of the cyber security policies ensures that the policies are kept-up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

Rationale for Requirement R2:

In response to FERC Order No. 791, Requirement R2 requires entities to develop and implement cyber security plans to meet specific security control objectives for assets containing low impact BES Cyber System(s). The cyber security plan(s) covers four subject matter areas: (1) cyber security awareness; (2) physical security controls; (3) electronic access controls; and (4) Cyber Security Incident response. This plan(s), along with the cyber security policies required under Requirement R1, Part 1.2, provides a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.

Considering the varied types of low impact BES Cyber Systems across the BES, Attachment 1 provides Responsible Entities flexibility on how to apply the security controls to meet the security objectives. Additionally, because many Responsible Entities have multiple-impact rated BES Cyber Systems, nothing in the requirement prohibits entities from using their high and medium impact BES Cyber System policies, procedures, and processes to implement security controls required for low impact BES Cyber Systems, as detailed in Requirement R2, Attachment 1.

Responsible Entities will use their identified assets containing low impact BES Cyber System(s) (developed pursuant to CIP-002) to substantiate the sites or locations associated with low impact BES Cyber System(s). However, there is no requirement or compliance expectation for Responsible Entities to maintain a list(s) of individual low impact BES Cyber System(s) and their associated cyber assets or to maintain a list of authorized users.

Rationale for Requirement R3:

The identification and documentation of the single CIP Senior Manager ensures that there is clear authority and ownership for the CIP program within an organization, as called for in Blackout Report Recommendation 43. The language that identifies CIP Senior Manager responsibilities is included in the Glossary of Terms used in NERC Reliability Standards so that it may be used across the body of CIP standards without an explicit cross-reference.

FERC Order No. 706, Paragraph 296, requests consideration of whether the single senior manager should be a corporate officer or equivalent. As implicated through the defined term, the senior manager has "the overall authority and responsibility for leading and managing implementation of the requirements within this set of standards" which ensures that the senior manager is of sufficient position in the Responsible Entity to ensure that cyber security receives the prominence that is necessary. In addition, given the range of business models for responsible entities, from municipal, cooperative, federal agencies, investor owned utilities, privately owned utilities, and everything in between, the SDT believes that requiring the CIP

Senior Manager to be a “corporate officer or equivalent” would be extremely difficult to interpret and enforce on a consistent basis.

Rationale for Requirement R4:

The intent of the requirement is to ensure clear accountability within an organization for certain security matters. It also ensures that delegations are kept up-to-date and that individuals do not assume undocumented authority.

In FERC Order No. 706, Paragraphs 379 and 381, the Commission notes that Recommendation 43 of the 2003 Blackout Report calls for "clear lines of authority and ownership for security matters." With this in mind, the Standard Drafting Team has sought to provide clarity in the requirement for delegations so that this line of authority is clear and apparent from the documented delegations.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This draft of CIP-003-7 is addressing the directive issued by the Federal Energy Regulatory Commission (Commission) in paragraph 73 of Order No. 822 which reads:

> [T]he Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term "direct" as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule approving revisions to the cybersecurity Critical Infrastructure Protection (CIP) standards.

Previously, the Guidelines and Technical Basis had approximately 10 pages of explanation and numerous reference models to describe different forms of direct vs. indirect access that could be used to determine whether Low Impact External Routable Connectivity existed and thus whether a Low Impact BES Cyber System Electronic Access Point (LEAP) was required.

In this revision, the term *Low Impact External Routable Connectivity* has been changed to *Low Impact External Routable Communication (LERC*) and simplified so that it is an attribute of a BES asset concerning whether there is routable protocol communications across the asset boundary without regard to 'direct vs. indirect' access that may occur. This greatly simplifies and clarifies the definition of LERC. It removes the dependency between the electronic access controls that may be in place and having those controls determine whether LERC exists or not. For those BES assets that have LERC, the SDT changed the requirement from requiring a LEAP to requiring electronic access controls to "permit only necessary electronic access to low impact BES Cyber Systems" (revised Attachment 1, Section 3.1) within the BES asset and expanded the Guidelines and Technical Basis with numerous examples of electronic access controls.

Given the modified definition of LERC and the proposed modifications in Reliability CIP-003-7, there is no longer a need for the NERC Glossary term Low Impact BES Cyber System Electronic Access Point (LEAP). Consequently, NERC is proposing that term for retirement.

In summary, the CIP Standard Drafting Team revised CIP-003-7, Attachments 1 and 2, Sections 2 and 3 and the associated High VSL for Requirement R2. Non-substantive errata changes were also made within the standard, including changing "ES-ISAC" to "E-ISAC".

Completed Actions	Date
Standard Authorization Request (SAR) approved	July 20, 2016
Draft 1 of CIP-003-7 posted for formal comment and initial ballot	July 21 – September 6, 2016

Anticipated Actions	Date
10-day final ballot	October, 2016
NERC Board of Trustees (BOT) adoption	November, 2016

A. Introduction

1. **Title:** Cyber Security — Security Management Controls

2. **Number:** CIP-003-7

3. **Purpose:** To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

   4.1.1 Balancing Authority

   4.1.2 Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

   4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:

   4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

   4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

   4.1.2.2 Each Special Protection System (SPS) or Remedial Action Scheme (RAS) where the SPS or RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

   4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

   4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

   4.1.3 Generator Operator

   4.1.4 Generator Owner

4.1.5 Interchange Coordinator or Interchange Authority

4.1.6 Reliability Coordinator

4.1.7 Transmission Operator

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each SPS or RAS where the SPS or RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-003-7:

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESPs).

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates:

See Implementation Plan for CIP-003-7.

6. Background:

Standard CIP-003 exists as part of a suite of CIP Standards related to cyber security, which require the initial identification and categorization of BES Cyber Systems and require organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems.

The term policy refers to one or a collection of written documents that are used to communicate the Responsible Entities' management goals, objectives and expectations for how the Responsible Entity will protect its BES Cyber Systems. The use of policies also establishes an overall governance foundation for creating a culture of security and compliance with laws, regulations, and standards.

The term documented processes refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in its documented processes, but it must address the applicable requirements.

The terms program and plan are sometimes used in place of documented processes where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as plans (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term program may refer to the organization's overall implementation of its policies, plans, and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Reliability Standards could also be referred to as a program. However, the terms program and plan do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high, medium, and low impact BES Cyber Systems. For example, a single

cyber security awareness program could meet the requirements across multiple BES Cyber Systems.

Measures provide examples of evidence to show documentation and implementation of the requirement. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the BES. A review of UFLS tolerances defined within Regional Reliability Standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

B. Requirements and Measures

R1. Each Responsible Entity shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 For its high impact and medium impact BES Cyber Systems, if any:

1.1.1. Personnel and training (CIP-004);

1.1.2. Electronic Security Perimeters (CIP-005) including Interactive Remote Access;

1.1.3. Physical security of BES Cyber Systems (CIP-006);

1.1.4. System security management (CIP-007);

1.1.5. Incident reporting and response planning (CIP-008);

1.1.6. Recovery plans for BES Cyber Systems (CIP-009);

1.1.7. Configuration change management and vulnerability assessments (CIP-010);

1.1.8. Information protection (CIP-011); and

1.1.9. Declaring and responding to CIP Exceptional Circumstances.

1.2 For its assets identified in CIP-002 containing low impact BES Cyber Systems, if any:

1.2.1. Cyber security awareness;

1.2.2. Physical security controls;

1.2.3. Electronic access controls for Low Impact External Routable Communication (LERC) and Dial-up Connectivity; and

1.2.4. Cyber Security Incident response

M1. Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.

R2. Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall implement one or more documented cyber security plan(s) for its low impact BES Cyber Systems that include the sections in Attachment 1. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

Note: An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required. Lists of authorized users are not required.

M2. Evidence shall include each of the documented cyber security plan(s) that collectively include each of the sections in Attachment 1 and additional evidence to demonstrate implementation of the cyber security plan(s). Additional examples of evidence per section are located in Attachment 2.

R3. Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the CIP Senior Manager.

R4. The Responsible Entity shall implement a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. An example of evidence may include, but is not limited to, a dated document, approved by the CIP Senior Manager, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information:

None.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**Medium**	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address one of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 15 calendar months but did	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address two of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 16 calendar months but did	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address three of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address four or more of the nine topics required by R1. (R1.1) OR The Responsible Entity did not have any documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1. (R1.1) OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			complete this review in less than or equal to 16 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of the previous approval. (R1.1)	complete this review in less than or equal to 17 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of the previous approval. (R1.1)	calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact	The Responsible Entity did not complete its review of the one or more documented cyber security policies as required by R1 within 18 calendar months of the previous review. (R1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R1.1)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address one of the four topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 within 15 calendar	OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address two of the four topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 within 16 calendar	BES Cyber Systems, but did not address three of the four topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its	OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address any of the four topics required by R1. (R1.2) OR The Responsible Entity did not have any documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1. (R1.2) OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			months but did complete this review in less than or equal to 16 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of	months but did complete this review in less than or equal to 17 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 16 calendar months but did complete this approval in less than or equal to 17	assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1.2)	The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R1.2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the previous approval. (R1.2)	calendar months of the previous approval. (R1.2)		
R2	**Operations Planning**	**Lower**	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document cyber security awareness according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document one or more Cyber Security	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to reinforce cyber security practices at least once every 15 calendar months according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented one or more incident response plans within its cyber security plan(s) for its assets containing	The Responsible Entity documented one or more Cyber Security Incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to test each Cyber Security Incident response plan(s) at least once every 36 calendar months according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented the determination of whether an identified Cyber Security Incident is a Reportable Cyber	The Responsible Entity failed to document or implement one or more cyber security plan(s) for its assets containing low impact BES Cyber Systems according to Requirement R2, Attachment 1. (R2).

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Incident response plans according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to update each Cyber Security Incident response plan(s) within 180 days according to Requirement R2, Attachment 1, Section 4. (R2)	low impact BES Cyber Systems, but failed to include the process for identification, classification, and response to Cyber Security Incidents according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and	Security Incident, but failed to notify the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented electronic access controls for its assets containing low impact BES Cyber Systems, but failed to implement the electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented the physical access controls for its	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented	assets containing low impact BES Cyber Systems, but failed to implement the physical security controls according to Requirement R2, Attachment 1, Section 2. (R2)	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2)		
R3	**Operations Planning**	**Medium**	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did document this change in less than 40 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar days but did document this change in less than 50 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in less than 60 calendar days of the change. (R3)	The Responsible Entity has not identified, by name, a CIP Senior Manager. OR The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 60 calendar

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						days of the change. (R3)
R4	**Operations Planning**	**Lower**	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 30 calendar days but did document this change in less than 40 calendar days of the change. (R4)	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 40 calendar days but did document this change in less than 50 calendar days of the change. (R4)	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 50 calendar days but did document this change in less than 60 calendar days of the change. (R4)	The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, but does not have a process to delegate actions from the CIP Senior Manager. (R4) OR The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 60 calendar days of the change. (R4)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.

Version	Date	Action	Change Tracking
5	11/22/13	FERC Order issued approving CIP-003-5.	
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from Order No. 791 related to identify, assess, and correct language and communication networks.
6	2/12/15	Adopted by the NERC Board of Trustees.	Replaces the version adopted by the Board on 11/13/2014. Revised version addresses remaining directives from Order No. 791 related to transient devices and low impact BES Cyber Systems.
6	1/21/16	FERC Order issued approving CIP-003-6. Docket No. RM15-14-000	
7	TBD	Adopted by the NERC Board of Trustees.	Revised to address FERC Order 822 directive regarding definition of LERC

Attachment 1

Required Sections for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Responsible Entities shall include each of the sections provided below in the cyber security plan(s) required under Requirement R2.

Responsible Entities with multiple-impact BES Cyber Systems ratings can utilize policies, procedures, and processes for their high or medium impact BES Cyber Systems to fulfill the sections for the development of low impact cyber security plan(s). Each Responsible Entity can develop a cyber security plan(s) either by individual asset or groups of assets.

Section 1. Cyber Security Awareness: Each Responsible Entity shall reinforce, at least once every 15 calendar months, cyber security practices (which may include associated physical security practices).

Section 2. Physical Security Controls: Each Responsible Entity shall control physical access, based on need as determined by the Responsible Entity, to (1) the asset or the locations of the low impact BES Cyber Systems within the asset, and (2) the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any.

Section 3. Electronic Access Controls: Each Responsible Entity shall:

3.1 Implement electronic access control(s) for LERC, if any, to permit only necessary electronic access to low impact BES Cyber System(s).

3.2 Implement authentication for all Dial-up Connectivity, if any, that provides access to low impact BES Cyber Systems, per Cyber Asset capability.

Section 4. Cyber Security Incident Response: Each Responsible Entity shall have one or more Cyber Security Incident response plan(s), either by asset or group of assets, which shall include:

4.1 Identification, classification, and response to Cyber Security Incidents;

4.2 Determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC), unless prohibited by law;

4.3 Identification of the roles and responsibilities for Cyber Security Incident response by groups or individuals;

4.4 Incident handling for Cyber Security Incidents;

4.5 Testing the Cyber Security Incident response plan(s) at least once every 36 calendar months by: (1) responding to an actual Reportable Cyber Security Incident; (2) using a drill or tabletop exercise of a Reportable Cyber Security

Incident; or (3) using an operational exercise of a Reportable Cyber Security Incident; and

4.6 Updating the Cyber Security Incident response plan(s), if needed, within 180 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident.

Attachment 2

Examples of Evidence for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Section 1. Cyber Security Awareness: An example of evidence for Section 1 may include, but is not limited to, documentation that the reinforcement of cyber security practices occurred at least once every 15 calendar months. The evidence could be documentation through one or more of the following methods:

- Direct communications (for example, e-mails, memos, or computer-based training);
- Indirect communications (for example, posters, intranet, or brochures); or
- Management support and reinforcement (for example, presentations or meetings).

Section 2. Physical Security Controls: Examples of evidence for Section 2 may include, but are not limited to:

- Documentation of the selected access control(s) (e.g., card key, locks, perimeter controls), monitoring controls (e.g., alarm systems, human observation), or other operational, procedural, or technical physical security controls that control physical access to both:
  a. The asset, if any, or the locations of the low impact BES Cyber Systems within the asset; and
  b. The Cyber Asset specified by the Responsible Entity that provides electronic access controls implemented for Section 3.1, if any.

Section 3. Electronic Access Controls: Examples of evidence for Section 3 may include, but are not limited to:

1. Documentation, such as representative diagrams or lists of implemented electronic access controls (e.g., restricting IP addresses, ports, or services; authenticating users; air-gapping networks; terminating routable protocol sessions on a non-BES Cyber Asset; implementing unidirectional gateways) showing that for LERC at each asset or group of assets containing low impact BES Cyber Systems, is confined only to that access the Responsible Entity deems necessary; and
2. Documentation of authentication for Dial-up Connectivity (e.g., dial out only to a preprogrammed number to deliver data, dial-back modems, modems that must be remotely controlled by the control center or control room, or access control on the BES Cyber System).

Section 4. Cyber Security Incident Response: An example of evidence for Section 4 may include, but is not limited to, dated documentation, such as policies, procedures, or process

documents of one or more Cyber Security Incident response plan(s) developed either by asset or group of assets that include the following processes:

1. to identify, classify, and respond to Cyber Security Incidents; to determine whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and for notifying the Electricity Information Sharing and Analysis Center (E-ISAC);
2. to identify and document the roles and responsibilities for Cyber Security Incident response by groups or individuals (e.g., initiating, documenting, monitoring, reporting, etc.);
3. for incident handling of a Cyber Security Incident (e.g., containment, eradication, or recovery/incident resolution);
4. for testing the plan(s) along with the dated documentation that a test has been completed at least once every 36 calendar months; and
5. to update, as needed, Cyber Security Incident response plan(s) within 180 calendar days after completion of a test or actual Reportable Cyber Security Incident.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

In developing policies in compliance with Requirement R1, the number of policies and their content should be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization, or as components of specific programs. The Responsible Entity has the flexibility to develop a single comprehensive cyber security policy covering the required topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-7, Requirement R1.

If a Responsible Entity has any high or medium impact BES Cyber Systems, the one or more cyber security policies must cover the nine subject matter areas required by CIP-003-7, Requirement R1, Part 1.1. If a Responsible Entity has identified from CIP-002 any *assets containing low impact BES Cyber Systems,* also referred to herein as BES assets, the one or more cyber security policies must cover the four subject matter areas required by Requirement R1, Part 1.2.

Responsible Entities that have multiple-impact rated BES Cyber Systems are not required to create separate cyber security policies for high, medium, or low impact BES Cyber Systems. The Responsible Entities have the flexibility to develop policies that cover all three impact ratings.

Implementation of the cyber security policy is not specifically included in CIP-003-7, Requirement R1 as it is envisioned that the implementation of this policy is evidenced through successful implementation of CIP-003 through CIP-011. However, Responsible Entities are

encouraged not to limit the scope of their cyber security policies to only those requirements in NERC cyber security Reliability Standards, but to develop a holistic cyber security policy appropriate for its organization. Elements of a policy that extend beyond the scope of NERC's cyber security Reliability Standards will not be considered candidates for potential violations although they will help demonstrate the organization's internal culture of compliance and posture towards cyber security.

For Part 1.1, the Responsible Entity should consider the following for each of the required topics in its one or more cyber security policies for medium and high impact BES Cyber Systems, if any:

1.1.1 Personnel and training (CIP-004)

- Organization position on acceptable background investigations
- Identification of possible disciplinary action for violating this policy
- Account management

1.1.2 Electronic Security Perimeters (CIP-005) including Interactive Remote Access

- Organization stance on use of wireless networks
- Identification of acceptable authentication methods
- Identification of trusted and untrusted resources
- Monitoring and logging of ingress and egress at Electronic Access Points
- Maintaining up-to-date anti-malware software before initiating Interactive Remote Access
- Maintaining up-to-date patch levels for operating systems and applications used to initiate Interactive Remote Access
- Disabling VPN "split-tunneling" or "dual-homed" workstations before initiating Interactive Remote Access
- For vendors, contractors, or consultants: include language in contracts that requires adherence to the Responsible Entity's Interactive Remote Access controls

1.1.3 Physical security of BES Cyber Systems (CIP-006)

- Strategy for protecting Cyber Assets from unauthorized physical access
- Acceptable physical access control methods
- Monitoring and logging of physical ingress

1.1.4 System security management (CIP-007)

- Strategies for system hardening
- Acceptable methods of authentication and access control

- Password policies including length, complexity, enforcement, prevention of brute force attempts
- Monitoring and logging of BES Cyber Systems

1.1.5 Incident reporting and response planning (CIP-008)

- Recognition of Cyber Security Incidents
- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

1.1.6 Recovery plans for BES Cyber Systems (CIP-009)

- Availability of spare components
- Availability of system backups

1.1.7 Configuration change management and vulnerability assessments (CIP-010)

- Initiation of change requests
- Approval of changes
- Break-fix processes

1.1.8 Information protection (CIP-011)

- Information access control methods
- Notification of unauthorized information disclosure
- Information access on a need-to-know basis

1.1.9 Declaring and responding to CIP Exceptional Circumstances

- Processes to invoke special procedures in the event of a CIP Exceptional Circumstance
- Processes to allow for exceptions to policy that do not violate CIP requirements

Requirements relating to exceptions to a Responsible Entity's security policies were removed because it is a general management issue that is not within the scope of a reliability requirement. It is an internal policy requirement and not a reliability requirement. However, Responsible Entities are encouraged to continue this practice as a component of their cyber security policies.

In this and all subsequent required approvals in the NERC CIP Reliability Standards, the Responsible Entity may elect to use hardcopy or electronic approvals to the extent that there is sufficient evidence to ensure the authenticity of the approving party.

Requirement R2:

Using the list of assets containing low impact BES Cyber Systems from CIP-002, the intent of the requirement is for each Responsible Entity to create, document, and implement one or more cyber security plan(s) that addresses objective criteria for the protection of low impact BES

Cyber Systems. The protections required by Requirement R2 reflect the level of risk that misuse or the unavailability of low impact BES Cyber Systems poses to the BES. The intent is that the required protections are part of a program that covers the low impact BES Cyber Systems collectively either at an asset or site level (assets containing low impact BES Cyber Systems), but not at an individual device or system level.

There are four subject matter areas, as identified in Attachment 1, that must be covered by the cyber security plan: (1) cyber security awareness, (2) physical security controls, (3) electronic access controls for LERC and Dial-up Connectivity, and (4) Cyber Security Incident response.

Requirement R2, Attachment 1

As noted, Attachment 1 contains the sections that must be in the cyber security plan(s). The intent is to allow entities that have a combination of high, medium, and low impact BES Cyber Systems the flexibility to choose, if desired, to cover their low impact BES Cyber Systems (or any subset) under their programs used for the high or medium impact BES Cyber Systems rather than maintain two separate programs. Guidance for each of the four subject matter areas of Attachment 1 is provided below.

Requirement R2, Attachment 1, Section 1 – Cyber Security Awareness

The intent of the cyber security awareness program is for entities to reinforce good cyber security practices with their personnel at least once every 15 calendar months. The entity has the discretion to determine the topics to be addressed and the manner in which it will communicate these topics. As evidence of compliance, the Responsible Entity should be able to produce the awareness material that was delivered according to the delivery method(s) (e.g., posters, emails, or topics at staff meetings, etc.). The Responsible Entity is not required to maintain lists of recipients and track the reception of the awareness material by personnel.

Although the focus of the awareness is cyber security, it does not mean that only technology-related topics can be included in the program. Appropriate physical security topics (e.g., tailgating awareness and protection of badges for physical security, or “If you see something, say something” campaigns, etc.) are valid for cyber security awareness. The intent is to cover topics concerning any aspect of the protection of BES Cyber Systems.

Requirement R2, Attachment 1, Section 2 – Physical Security Controls

The Responsible Entity must document and implement methods to control physical access to (1) the asset or the locations of low impact BES Cyber Systems within the asset, and (2) Cyber Assets that implement the electronic access control(s) specified by the Responsible Entity in Section 3, if any. If these Cyber Assets are located within the BES asset and inherit the same controls outlined in Section 2, this can be noted by the Responsible Entity in either its policies or cyber security plan(s) to avoid duplicate documentation of the same controls.

The Responsible Entity has the flexibility in the selection of the methods used to meet the objective to control physical access to the asset(s) containing low impact BES Cyber System(s) or the low impact BES Cyber Systems themselves, as well as physical protection of the electronic access control Cyber Assets specified by the Responsible Entity, if any. The Responsible Entity may use one or a combination of access controls, monitoring controls, or

other operational, procedural, or technical physical security controls. Entities may use perimeter controls (e.g., fences with locked gates, guards, or site access policies, etc.) or more granular areas of physical access control in areas where low impact BES Cyber Systems are located, such as control rooms or control houses. User authorization programs and lists of authorized users for physical access are not required although they are an option to meet the security objective.

The objective is to control the physical access based on need as determined by the Responsible Entity. The need can be documented at the policy level for access to the site or systems. The requirement does not obligate an entity to specify a need for each access or authorization of a user for access.

Monitoring as a physical security control can be used as a complement or an alternative to access control. Examples of monitoring controls include, but are not limited to: (1) alarm systems to detect motion or entry into a controlled area, or (2) human observation of a controlled area. Monitoring does not necessarily require logging and maintaining logs but could include monitoring that physical access has occurred or been attempted (e.g., door alarm, or human observation, etc.). The monitoring does not need to be per low impact BES Cyber System but should be at the appropriate level to meet the security objective.

Requirement R2, Attachment 1, Section 3 – Electronic Access Controls

Section 3 requires the establishment of electronic access controls for *assets containing low impact BES Cyber Systems,* also referred to herein as BES assets when external routable protocol communication (LERC) or Dial-up Connectivity is present to or from the asset containing the low impact BES Cyber System(s). The establishment of electronic access controls is intended to reduce the risks associated with uncontrolled communication using routable protocols or Dial-up Connectivity. In the case where there is no LERC or Dial-up Connectivity, the Responsible Entity can document the absence of such communication in its low impact cyber security plan(s).

When identifying electronic access controls, Responsible Entities are provided flexibility in the selection of the controls that meet their operational needs while meeting the security objective of allowing only necessary electronic access to low impact BES Cyber Systems.

In essence, Responsible Entities are to determine LERC or Dial-up Connectivity for their BES assets and then, if present, document and implement electronic access control(s).

Determining LERC

The defined term Low Impact External Routable Communication (LERC) is used to avoid confusion with the term External Routable Connectivity (ERC) used for high and medium impact BES Cyber Systems as these terms are different concepts. The input to this requirement from CIP-002 is a list of assets containing low impact BES Cyber Systems, therefore LERC is an attribute of a BES asset and involves routable protocol communications to or from the BES asset (crossing the asset boundary) without regard to connectivity to Cyber Assets within the BES asset. ERC on the other hand is an attribute of an individual high or medium impact BES Cyber System and is relative to an Electronic Security Perimeter (ESP).

With LERC being a BES asset level attribute, it is used as a higher level filter to exclude from further consideration those assets containing low impact BES Cyber Systems that have no routable protocol communications to them from outside the BES asset. Responsible Entities can then concentrate their electronic access control efforts on those BES assets that do have LERC. However, this also means that LERC can exist for a BES asset even if there is no routable protocol connectivity to any low impact BES Cyber System within the BES asset.

In order to avoid future technology issues, the LERC definition specifically excludes communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions between non-Control Center BES assets containing low impact BES Cyber Systems, such as IEC 61850 messaging. This does not exclude Control Center to field communication but rather excludes the communication between the intelligent electronic devices (e.g. relays) in the field. A Responsible Entity using this technology is not expected to implement the electronic access controls noted herein. This exception was included so as not to inhibit the functionality of the time-sensitive requirements related to this technology nor to preclude the use of such time-sensitive reliability enhancing functions if they use a routable protocol in the future.

Determining Asset Boundary

As LERC is a BES asset level attribute, it involves a determination by the Responsible Entity of a BES asset boundary for their assets containing low impact BES Cyber Systems. This boundary will vary by BES asset type (Control Center, substation, generation resource) and the specific configuration of the BES asset. The intent is for the Responsible Entity to define the BES asset boundary such that the low impact BES Cyber System(s) that are located at the BES asset are contained within the BES asset boundary. This is strictly for determining what constitutes the BES "asset" and for determining which routable protocol communications and networks are *internal* or *inside* or *local* to the BES asset and which are *external to or outside* the BES asset. This is not an Electronic Security Perimeter or Physical Security Perimeter as defined for medium and high impact BES Cyber Systems. For the asset containing low impact BES Cyber System(s), the BES asset boundary is synonymous to the concept of a "logical border" demarcation where routable protocol communication (e.g. LERC) enters and exits the BES asset containing the low impact BES Cyber System. Some examples of ways a Responsible Entity may determine BES asset boundaries are:

- For Control Centers
  - Designated areas (room(s) or floor(s)) if the Control Center is located within a larger building.
  - A building if in a dedicated building on a shared campus.
  - The property/fence line if the Control Center is a dedicated facility on dedicated property.
- For substations, this could be the property/fence line or the control house.

- For generation resources:
  - Fossil/hydro generating facilities: This could be the property/fence line. If pumps or wells or other equipment that are part of the plant asset are outside the property line, then the BES asset boundary could expand to accommodate all that is considered part of the plant.
  - Solar farms: This could be the property line(s) or fence(s) surrounding all solar panels and interconnection facilities.
  - Wind farms: This could be the collection of individual turbines plus the equipment needed for interconnection.
  - Cogeneration facilities: This could be the identified portion of the larger plant that performs generation.

Determining Electronic Access Controls

Once a Responsible Entity has determined that LERC exists at the BES asset boundary, the Responsible Entity documents and implements its chosen electronic access control(s). The control(s) must allow only "necessary" access as determined by the Responsible Entity and they need to be able to explain the reasons for the electronic access permitted with their electronic access controls. The reasoning for the "necessary" access controls can be documented within the Responsible Entity's cyber security plan(s) or other policies or procedures associated with the electronic access controls.

Concept Diagrams

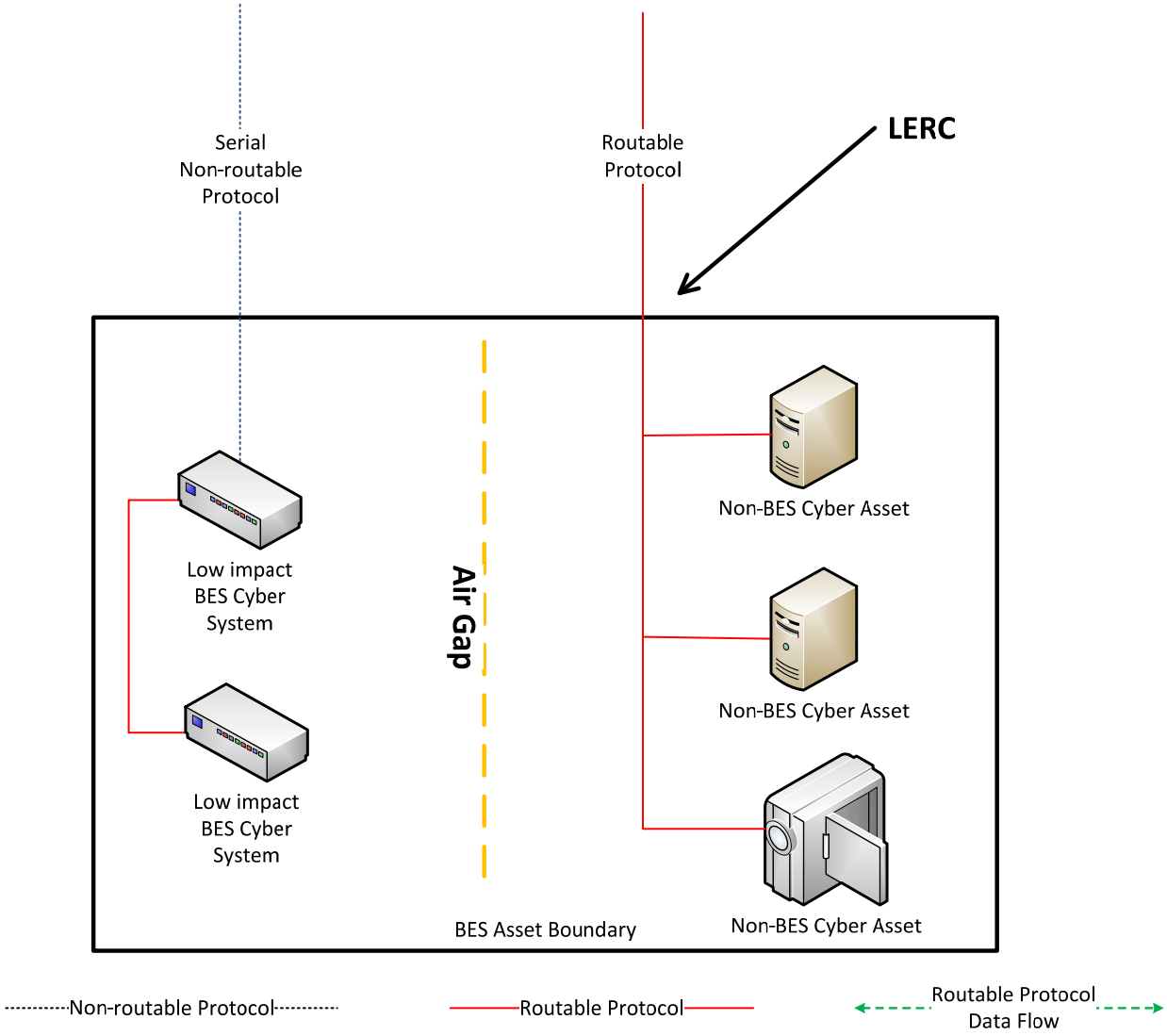
The diagrams on the following pages are provided as examples to illustrate various electronic access controls at a conceptual level. Regardless of the concepts or configurations chosen by the Responsible Entity, the security objective of permitting only necessary access to low impact BES Cyber Systems must be met when there is LERC to a BES asset.

NOTE:

- This is not an exhaustive list of applicable concepts.
- LERC is present in each diagram.
- The same legend is used in each diagram; however, the diagram may not contain all of the articles represented in the legend.
- The term "BES Asset Boundary" is capitalized in the diagrams but it is not a defined term.

LERC Reference Model 1 – Physical Isolation

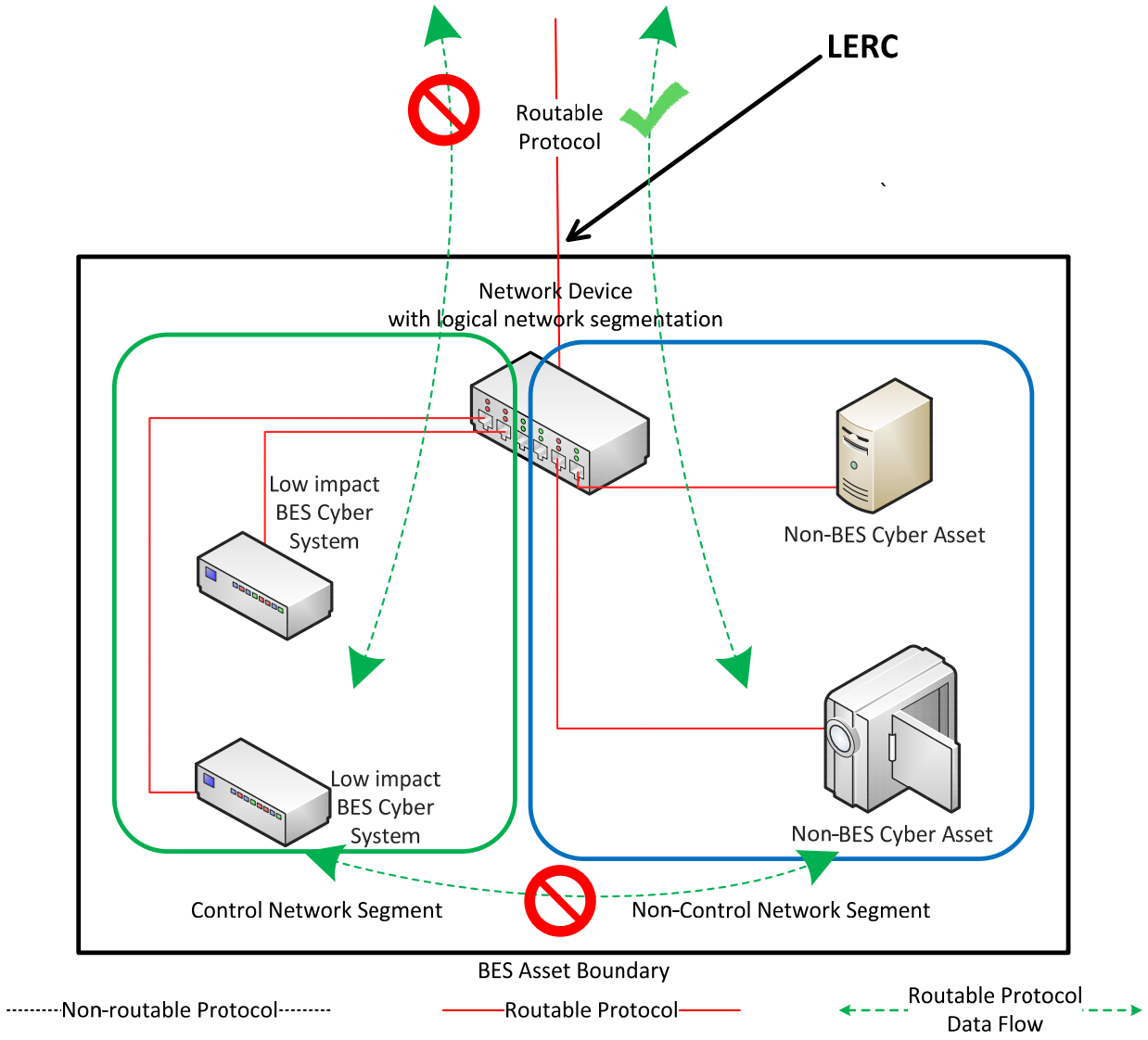
The Responsible Entity may choose to physically isolate the low impact BES Cyber System(s) from the LERC. This control is commonly referred to as an 'air gap'. The serial non-routable protocol connection and the routable protocol LERC are completely isolated from each other. There is no equipment shared with the low impact BES Cyber System(s).



Reference Model 1

LERC Reference Model 2 – Logical Isolation

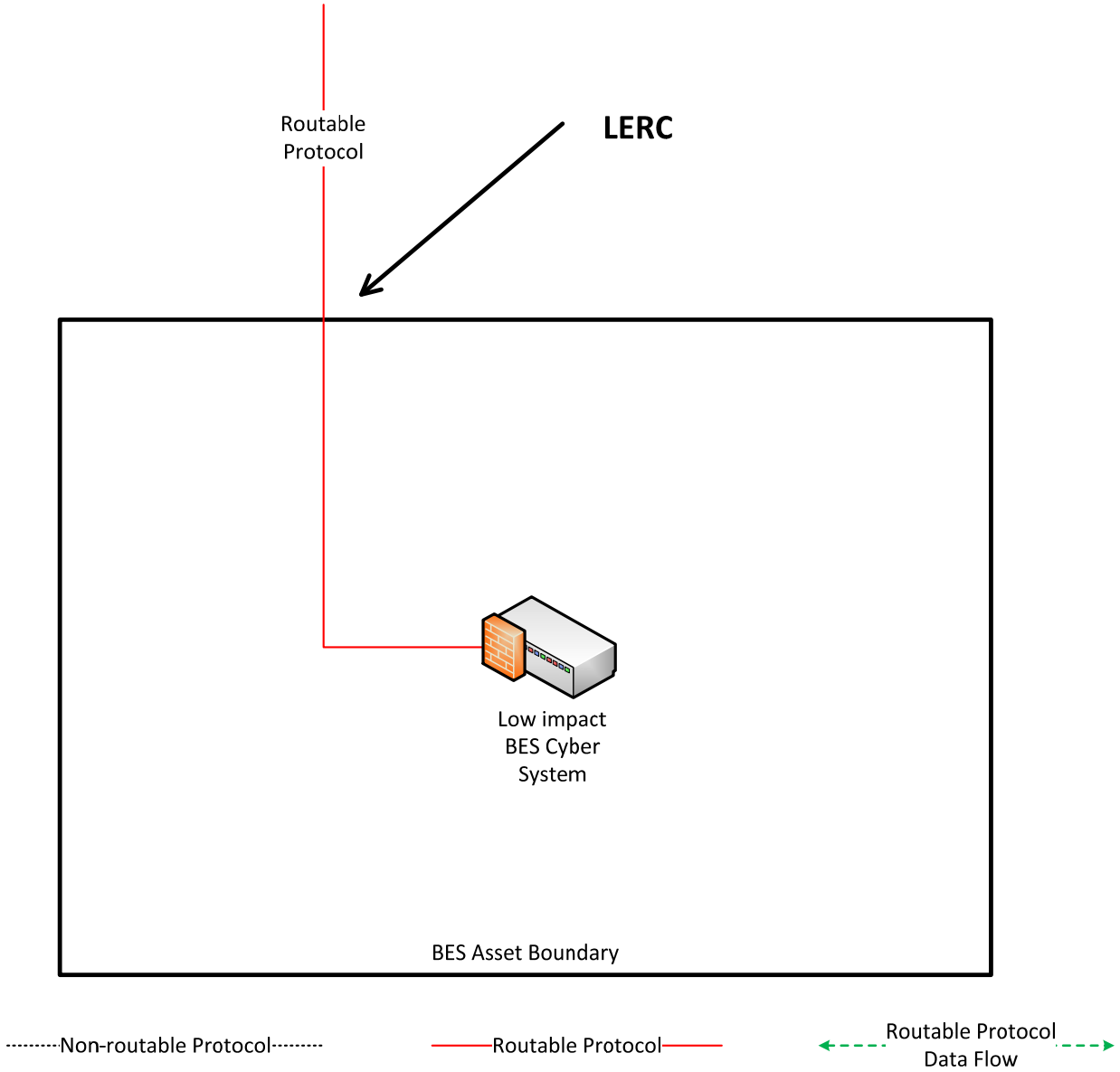
The Responsible Entity may choose to logically isolate the low impact BES Cyber System(s) from the LERC. The low impact BES Cyber System(s) is on an isolated network segment with logical controls preventing routable protocol communication into or out of the network containing the low impact BES Cyber System(s).



Reference Model 2

LERC Reference Model 3 – Host-based Inbound & Outbound Access Permissions

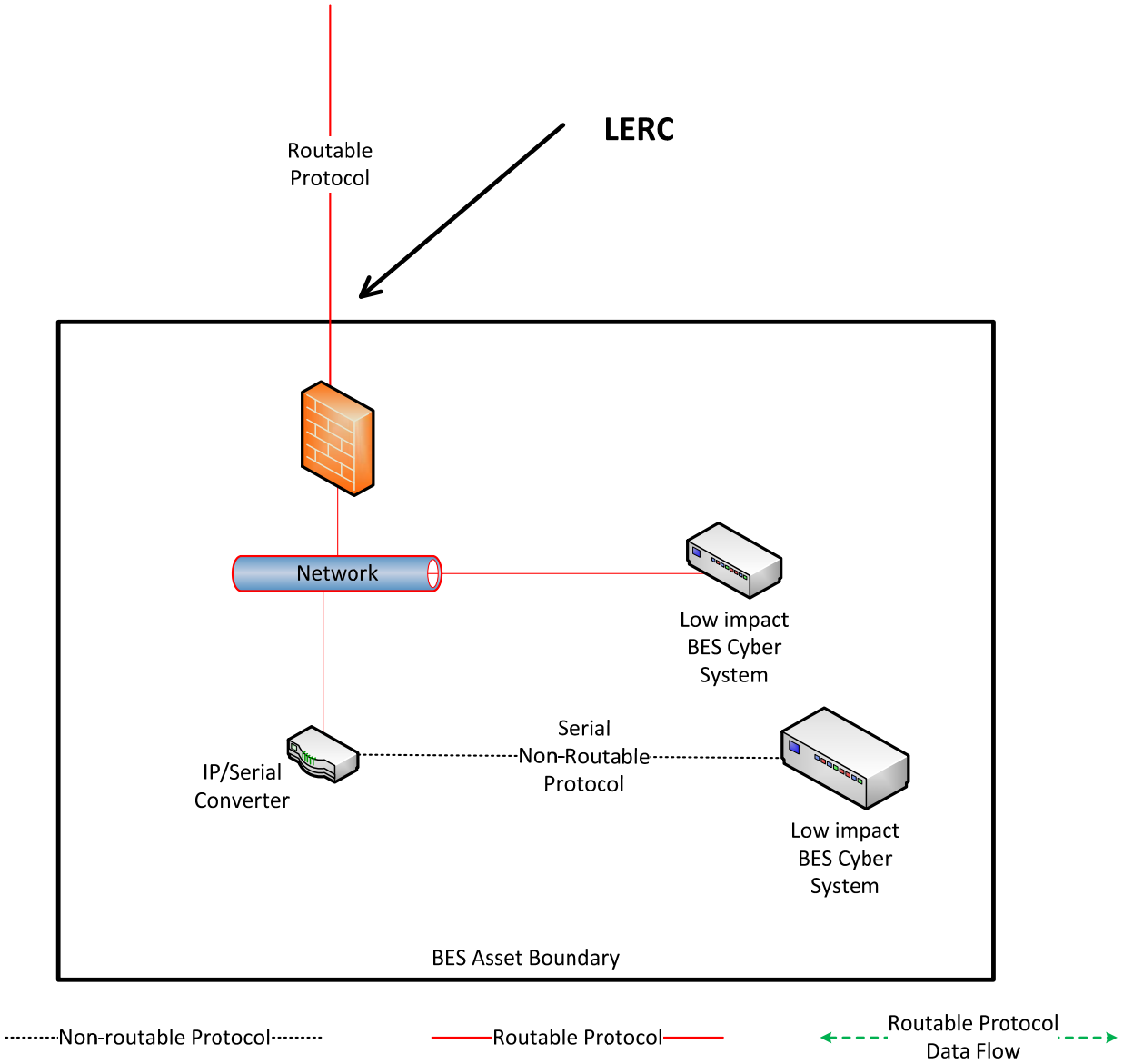
The Responsible Entity may choose to utilize a host-based firewall technology on the low impact BES Cyber System(s) that manages electronic access permission so that only necessary inbound and outbound routable protocol access is allowed to the low impact BES Cyber System(s).



Reference Model 3

LERC Reference Model 4 – Network-based Inbound & Outbound Access Permissions

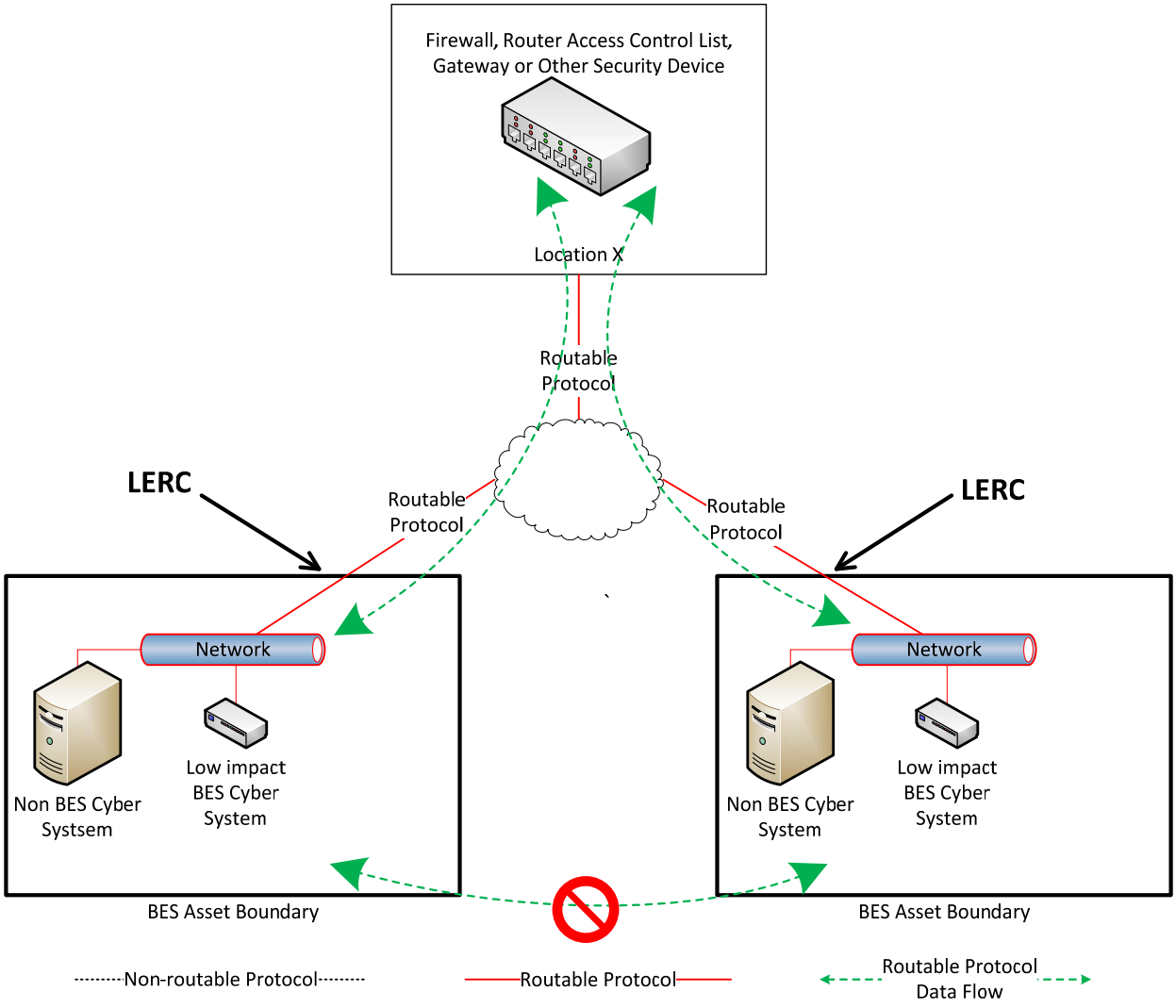
The Responsible Entity may choose to utilize a security device that permits only necessary access to the low impact BES Cyber System(s) within the BES asset. In this example, two low impact BES Cyber Systems are accessed over the LERC as the IP/Serial converter is continuing the same communications session from device(s) outside the BES asset boundary to the low impact BES Cyber Systems. The security device provides the electronic access controls to permit only necessary inbound and outbound routable protocol access to the low impact BES Cyber Systems.



Reference Model 4

LERC Reference Model 5 – Centralized Network-based Inbound & Outbound Access Permissions

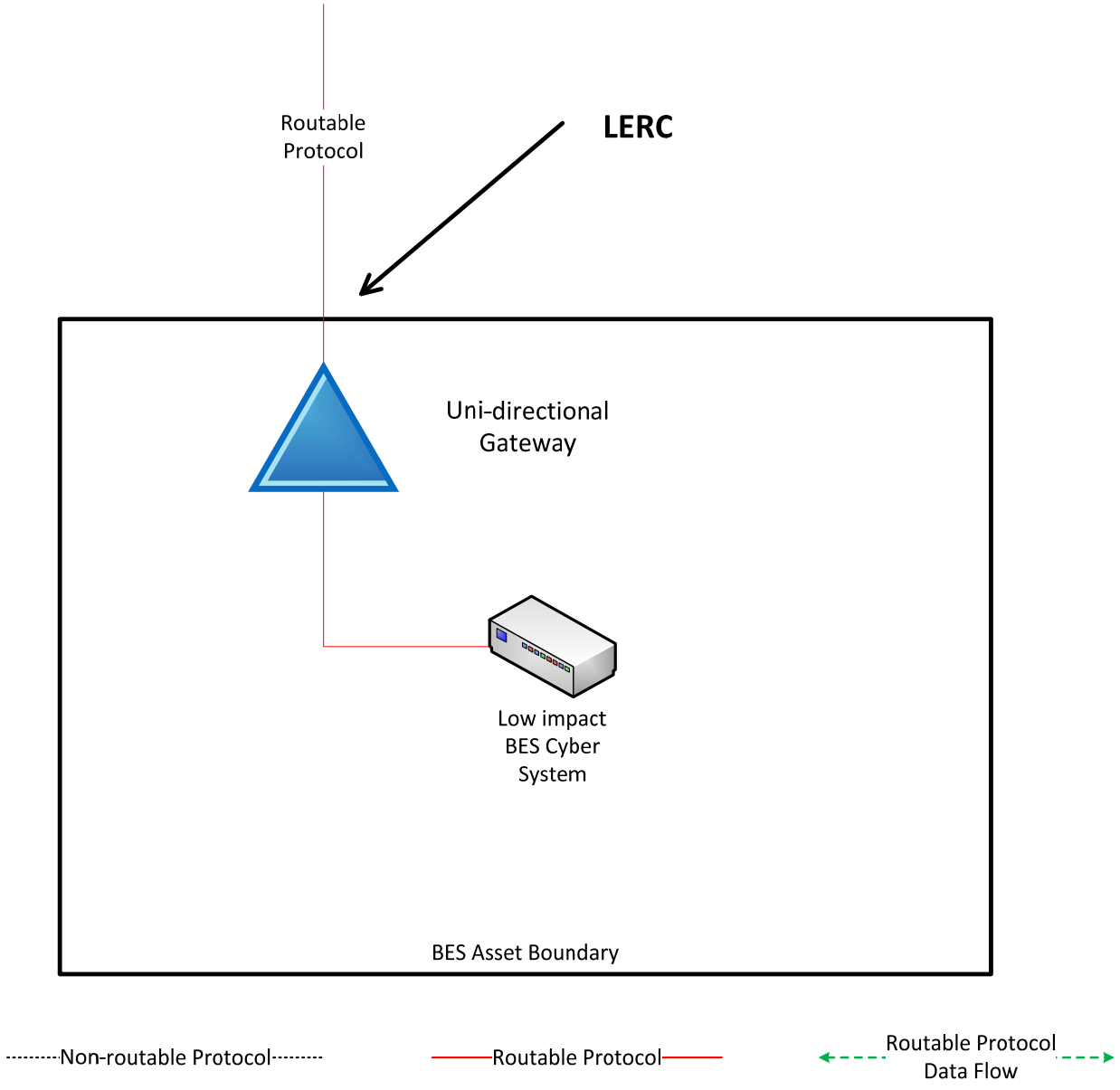
The Responsible Entity may choose to utilize a security device at a centralized location that may or may not be another BES asset. The electronic access control(s) do not necessarily have to reside inside the asset containing the low impact BES Cyber System(s). A security device is in place at "Location X" to act as the electronic access control and permit only necessary inbound and outbound routable protocol access to the low impact BES Cyber System(s). Care should be taken that electronic access to or between each BES asset is through the electronic access controls at the centralized location.



Reference Model 5

LERC Reference Model 6 – Uni-directional Gateway

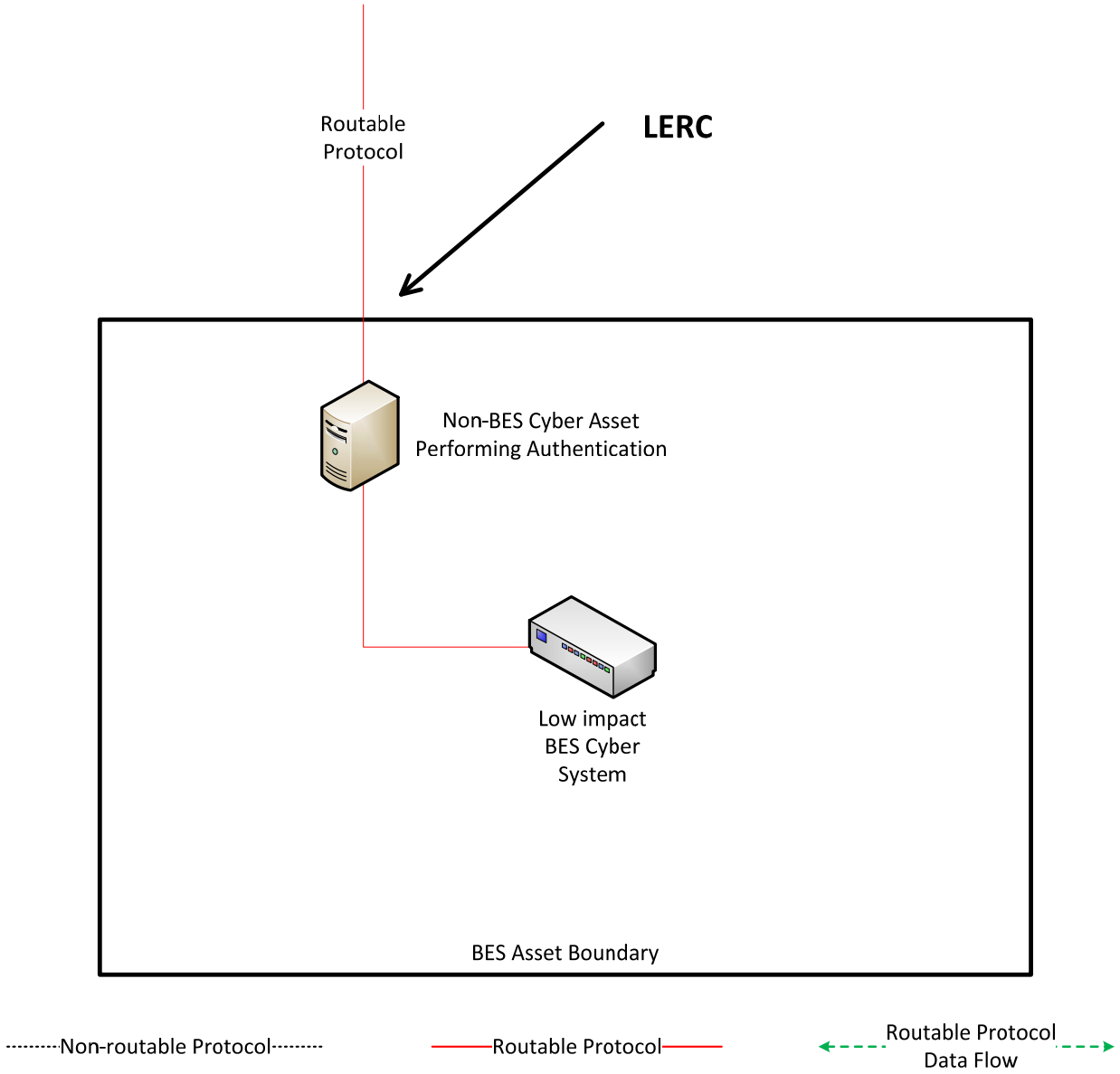
The Responsible Entity may choose to utilize a uni-directional gateway as the electronic access control. The low impact BES Cyber System(s) is not accessible (data cannot flow into the low impact BES Cyber System) from the LERC due to the implementation of a "one-way" (uni-directional) path for data to flow across the BES asset boundary.



Reference Model 6

LERC Reference Model 7 – User Authentication

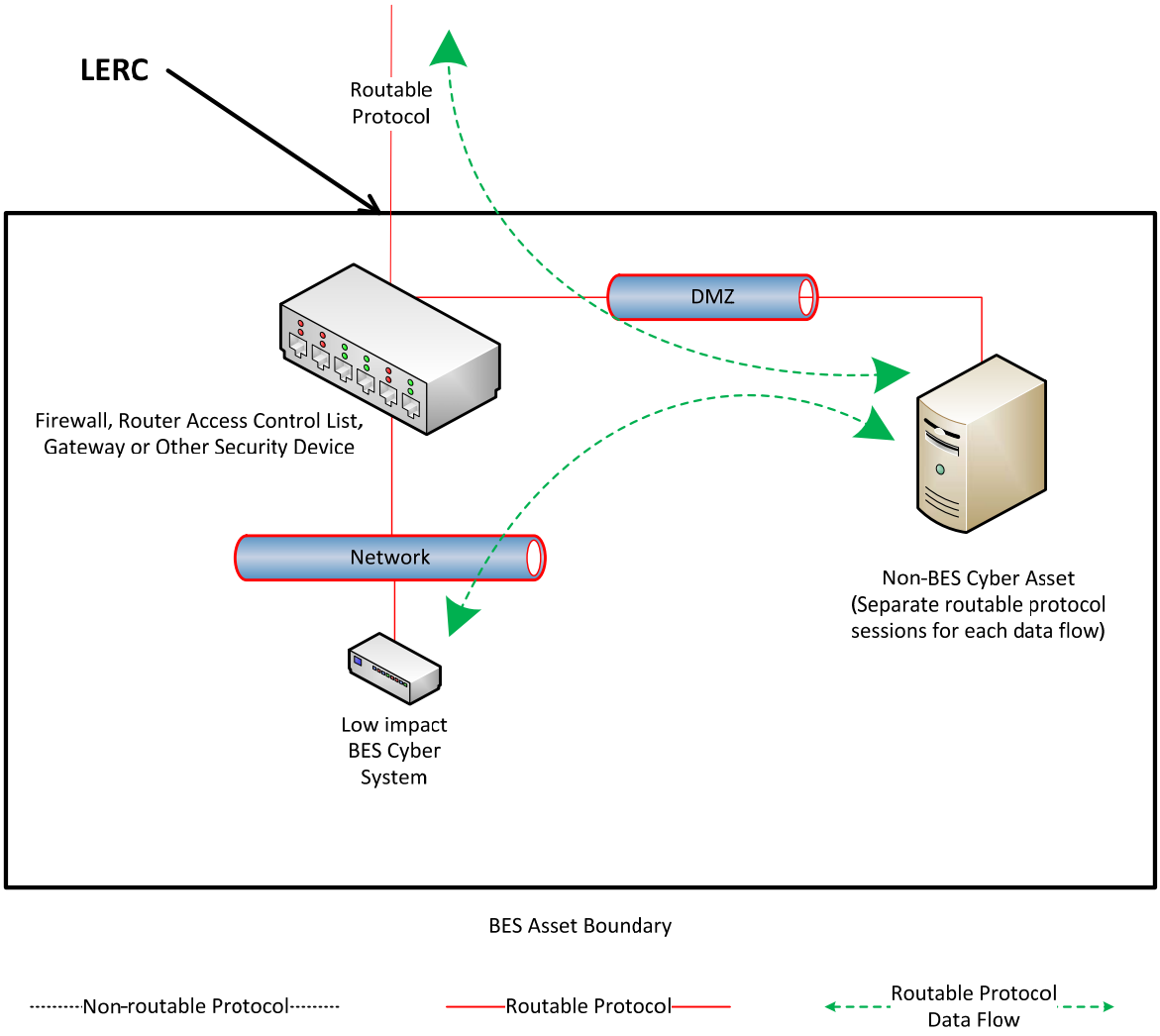
The Responsible Entity may choose to utilize a non-BES Cyber Asset between the network outside the BES asset boundary and the low impact BES Cyber System to perform user authentication for interactive access. The non-BES Cyber Asset would require authentication before establishing a new connection to the low impact BES Cyber System. The electronic access control depicted in this reference model may not meet the security objective for controlling device-to-device communication across the LERC depending on the specific system configuration in place.



Reference Model 7

LERC Reference Model 8 – Session Termination

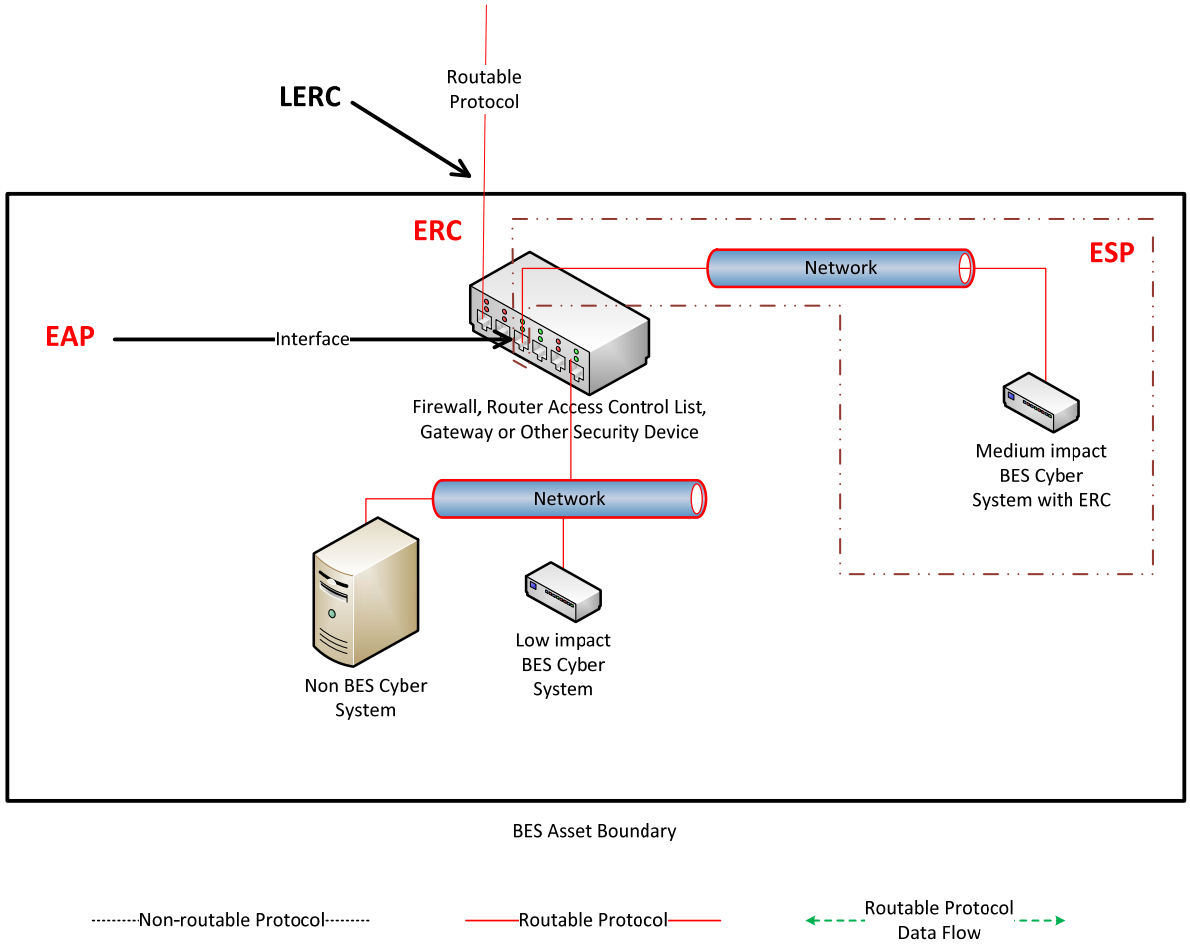
The Responsible Entity may choose to terminate routable protocol application sessions at a non-BES Cyber Asset inside the asset containing the low impact BES Cyber System(s) such that a separate application session is established to the low impact BES Cyber System(s) from the non-BES Cyber Asset (the routable session from outside the BES asset). The Responsible Entity may choose to authenticate access at a non-BES Cyber Asset either outside BES asset boundary or inside the asset containing the low impact BES Cyber System(s) such that unauthenticated access to the low impact BES Cyber System(s) is prohibited. The non-BES Cyber Asset sits on a demilitarized zone (DMZ) between the network outside the BES asset boundary and the low impact BES Cyber System(s). The non-BES Cyber Asset in the DMZ terminates the routable protocol session and establishes a new session to the low impact BES Cyber System(s). Additionally, a security device permits traffic from the network outside the BES asset boundary to flow only to and from the non-BES Cyber Asset in the DMZ (the routable session to the low impact BES Cyber System).



Reference Model 8

LERC Reference Model 9 – LERC and ERC

There is both LERC and ERC present in this reference model because there is at least one medium impact BES Cyber System and one low impact BES Cyber System within the BES asset. The Responsible Entity may choose to leverage an interface on the medium impact Electronic Access Control or Monitoring Systems (EACMS) device to provide electronic access controls for the LERC. The EACMS is therefore performing multiple functions – as a medium impact EACMS and as implementing low impact electronic access controls.



Reference Model 9

Dial-up Connectivity

Dial-up Connectivity to a low impact BES Cyber System is set to dial out only (no auto-answer) to a preprogrammed number to deliver data. Incoming Dial-up Connectivity is to a dialback modem, a modem that must be remotely controlled by the control center or control room, has some form of access control, or the low impact BES Cyber System has access control.

Insufficient Access Controls

Some examples of situations that would lack sufficient access controls to meet the intent of this requirement include:

- An asset has Dial-up Connectivity and a low impact BES Cyber System is reachable via an auto-answer modem that connects any caller to the Cyber Asset that has a default password. There is no practical access control in this instance.
- An asset has LERC due to a BES Cyber System within it having a wireless card on a public carrier that allows the BES Cyber System to be reachable via a public IP address. In essence, low impact BES Cyber Systems should not be accessible from the Internet and search engines such as Shodan.
- Dual-homing or multiple-network interface cards without disabling IP forwarding in the non-BES Cyber Asset within the DMZ to provide separation between the low impact BES Cyber System(s) and the external network would not meet the intent of "controlling" inbound and outbound electronic access assuming there was no other host-based firewall or other security devices on the non-BES Cyber Asset.

Requirement R2, Attachment 1, Section 4 – Cyber Security Incident Response

The entity should have one or more documented Cyber Security Incident response plan(s) that include each of the topics listed in Section 4. If, in the normal course of business, suspicious activities are noted at an asset containing low impact BES Cyber System(s), the intent is for the entity to implement a Cyber Security Incident response plan that will guide the entity in responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Entities are provided the flexibility to develop their Attachment 1, Section 4 Cyber Security Incident response plan(s) by asset or group of assets. The plans do not need to be on a per asset site or per low impact BES Cyber System basis. Entities can choose to use a single enterprise-wide plan to fulfill the obligations for low impact BES Cyber Systems.

The plan(s) must be tested once every 36 months. This is not an exercise per low impact BES Cyber Asset or per type of BES Cyber Asset but rather is an exercise of each incident response plan the entity created to meet this requirement. An actual Reportable Cyber Security Incident counts as an exercise as do other forms of tabletop exercises or drills. NERC-led exercises such as GridEx participation would also count as an exercise provided the entity's response plan is followed. The intent of the requirement is for entities to keep the Cyber Security Incident response plan(s) current, which includes updating the plan(s), if needed, within 180 days following a test or an actual incident.

For low impact BES Cyber Systems, the only portion of the definition of Cyber Security Incident that would apply is, "A malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of a BES Cyber System." The other portion of that definition is not to be used to require ESPs and PSPs for low impact BES Cyber Systems.

Requirement R3:

The intent of CIP-003-7, Requirement R3 is effectively unchanged since prior versions of the standard. The specific description of the CIP Senior Manager has now been included as a defined term rather than clarified in the Reliability Standard itself to prevent any unnecessary cross-reference to this standard. It is expected that the CIP Senior Manager will play a key role in ensuring proper strategic planning, executive/board-level awareness, and overall program governance.

Requirement R4:

As indicated in the rationale for CIP-003-7, Requirement R4, this requirement is intended to demonstrate a clear line of authority and ownership for security matters. The intent of the SDT was not to impose any particular organizational structure, but, rather, the intent is to afford the Responsible Entity significant flexibility to adapt this requirement to its existing organizational structure. A Responsible Entity may satisfy this requirement through a single delegation document or through multiple delegation documents. The Responsible Entity can make use of the delegation of the delegation authority itself to increase the flexibility in how this applies to its organization. In such a case, delegations may exist in numerous documentation records as long as the collection of these documentation records shows a clear line of authority back to the CIP Senior Manager. In addition, the CIP Senior Manager could also choose not to delegate any authority and meet this requirement without such delegation documentation.

The Responsible Entity must keep its documentation of the CIP Senior Manager and any delegations up-to-date. This is to ensure that individuals do not assume any undocumented authority. However, delegations do not have to be re-instated if the individual who delegated the task changes roles or the individual is replaced. For instance, assume that John Doe is named the CIP Senior Manager and he delegates a specific task to the Substation Maintenance Manager. If John Doe is replaced as the CIP Senior Manager, the CIP Senior Manager documentation must be updated within the specified timeframe, but the existing delegation to the Substation Maintenance Manager remains in effect as approved by the previous CIP Senior Manager, John Doe.

Rationale:

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

Rationale for Requirement R1:

One or more security policies enable effective implementation of the requirements of the cyber security Reliability Standards. The purpose of policies is to provide a management and governance foundation for all requirements that apply to a Responsible Entity's BES Cyber

Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the requirements.

Annual review and approval of the cyber security policies ensures that the policies are kept-up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

Rationale for Requirement R2:

In response to FERC Order No. 791, Requirement R2 requires entities to develop and implement cyber security plans to meet specific security control objectives for assets containing low impact BES Cyber System(s). The cyber security plan(s) covers four subject matter areas: (1) cyber security awareness; (2) physical security controls; (3) electronic access controls; and (4) Cyber Security Incident response. This plan(s), along with the cyber security policies required under Requirement R1, Part 1.2, provides a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.

Considering the varied types of low impact BES Cyber Systems across the BES, Attachment 1 provides Responsible Entities flexibility on how to apply the security controls to meet the security objectives. Additionally, because many Responsible Entities have multiple-impact rated BES Cyber Systems, nothing in the requirement prohibits entities from using their high and medium impact BES Cyber System policies, procedures, and processes to implement security controls required for low impact BES Cyber Systems, as detailed in Requirement R2, Attachment 1.

Responsible Entities will use their identified assets containing low impact BES Cyber System(s) (developed pursuant to CIP-002) to substantiate the sites or locations associated with low impact BES Cyber System(s). However, there is no requirement or compliance expectation for Responsible Entities to maintain a list(s) of individual low impact BES Cyber System(s) and their associated cyber assets or to maintain a list of authorized users.

Rationale for Requirement R3:

The identification and documentation of the single CIP Senior Manager ensures that there is clear authority and ownership for the CIP program within an organization, as called for in Blackout Report Recommendation 43. The language that identifies CIP Senior Manager responsibilities is included in the Glossary of Terms used in NERC Reliability Standards so that it may be used across the body of CIP standards without an explicit cross-reference.

FERC Order No. 706, Paragraph 296, requests consideration of whether the single senior manager should be a corporate officer or equivalent. As implicated through the defined term, the senior manager has "the overall authority and responsibility for leading and managing implementation of the requirements within this set of standards" which ensures that the senior manager is of sufficient position in the Responsible Entity to ensure that cyber security receives the prominence that is necessary. In addition, given the range of business models for responsible entities, from municipal, cooperative, federal agencies, investor owned utilities, privately owned utilities, and everything in between, the SDT believes that requiring the CIP

Senior Manager to be a “corporate officer or equivalent” would be extremely difficult to interpret and enforce on a consistent basis.

Rationale for Requirement R4:

The intent of the requirement is to ensure clear accountability within an organization for certain security matters. It also ensures that delegations are kept up-to-date and that individuals do not assume undocumented authority.

In FERC Order No. 706, Paragraphs 379 and 381, the Commission notes that Recommendation 43 of the 2003 Blackout Report calls for “clear lines of authority and ownership for security matters.” With this in mind, the Standard Drafting Team has sought to provide clarity in the requirement for delegations so that this line of authority is clear and apparent from the documented delegations.

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Proposed Revised Term: "Low Impact External Routable Communication" (LERC)

Revised Term: Low Impact External Routable Communication (LERC)

Revised Definition:

Routable protocol communication that crosses the boundary of an asset containing one or more low impact BES Cyber System(s), excluding communications between intelligent electronic devices used for time-sensitive protection or control functions between non-Control Center BES assets containing low impact BES Cyber Systems including, but not limited to, IEC 61850 GOOSE or vendor proprietary protocols.

Redline to Currently Approved Definition: "Low Impact External Routable Connectivity" (LERC)

Routable protocol communication that crosses the boundary of an asset containing one or more~~Direct user-initiated interactive access or a direct device-to-device connection to a~~ low impact BES Cyber System(s), excluding ~~from a Cyber Asset outside the asset containing those low impact BES Cyber System(s) via a bi-directional routable protocol connection. Point-to-point~~ communications between intelligent electronic devices ~~that~~ used ~~routable communication protocols~~ for time-sensitive protection or control functions between non-Control Center BES ~~Transmission station or substation~~ assets containing low impact BES Cyber Systems including,~~are excluded from this definition (examples of this communication include~~ but ~~are~~ not limited to, IEC 61850 GOOSE or vendor proprietary protocols~~)~~.

Currently Approved Definition of "Low Impact External Routable Connectivity" (LERC):

Direct user-initiated interactive access or a direct device-to-device connection to a low impact BES Cyber System(s) from a Cyber Asset outside the asset containing those low impact BES Cyber System(s) via a bi-directional routable protocol connection. Point-to-point communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions between Transmission station or substation assets containing low impact BES Cyber Systems are excluded from this definition (examples of this communication include, but are not limited to, IEC 61850 GOOSE or vendor proprietary protocols).

Retire Currently Approved Term "Low Impact BES Cyber System Electronic Access Point" (LEAP):

Given the modified definition of LERC and the proposed modifications in Reliability CIP-003-7, there is no longer a need for the NERC Glossary term *Low Impact BES Cyber System Electronic Access Point* (LEAP):

> A Cyber Asset interface that controls Low Impact External Routable Connectivity. The Cyber Asset containing the LEAP may reside at a location external to the asset or assets containing low impact BES Cyber Systems.

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Implementation Plan

Project 2016-02 Modifications to CIP Standards
Reliability Standard CIP-003-7 Security Management Controls and Low Impact External Routable Communication (LERC)

Requested Approvals

- Reliability Standard CIP-003-7 - Cyber Security – Security Management Controls
- Definition of Low Impact External Routable Communication (LERC)

Requested Retirements

- Reliability Standard CIP-003-6 - Cyber Security – Security Management Controls
- Definition Low Impact BES Cyber System Electronic Access Point (LEAP)
- Definition of Low Impact External Routable Connectivity (LERC)

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Interchange Coordinator or Interchange Authority
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Background

On January 21, 2016, the Federal Energy Regulatory Commission (Commission) issued Order No. 822, *Revised Critical Infrastructure Protection Reliability Standards,* approving seven Critical Infrastructure Protection (CIP) Reliability Standards and new or modified definitions. In addition to approving the seven CIP Reliability Standards, the Commission, among other things, directed NERC to modify the definition of LERC. The Commission stated:

> 73. Based on the comments received in response to the NOPR, the Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term "direct" as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule. We agree with NERC and other commenters that a suitable means to address our concern is to modify the Low Impact External Routable Connectivity

definition consistent with the commentary in the Guidelines and Technical Basis section of CIP-003-6.

In addition to modifying the definition consistent with the Commission's directive, the standard drafting team revised the term "LERC" by replacing the word "connectivity" with the word "communication" such that the proposed term for inclusion in the Glossary of Terms used in NERC Reliability Standards (NERC Glossary) is "Low Impact External Routable Communication."

Given the modified definition of LERC and the proposed modifications in Reliability CIP-003-7, there is no longer a need for the NERC Glossary term Low Impact BES Cyber System Electronic Access Point (LEAP). Consequently, NERC is proposing to retire the term LEAP.

General Considerations

This Implementation Plan does not modify the effective date for CIP-003-6 in the Implementation Plan associated with CIP-003-6 nor any of the phased-in compliance dates included therein.

Effective Date

The effective date for the proposed Reliability Standard and NERC Glossary term is provided below:

Where approval by an applicable governmental authority is required, Reliability Standard CIP-003-7 and the NERC Glossary term *Low Impact External Routable Communication* (LERC) shall become effective on the later of September 1, 2018 or the first day of the first calendar quarter that is nine (9) calendar months after the effective date of the applicable governmental authority's order approving the standard and NERC Glossary term, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard CIP-003-7 and the NERC Glossary term *Low Impact External Routable Communication* (LERC) shall become effective on the first day of the first calendar quarter that is nine (9) calendar months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Planned or Unplanned Changes

Planned or Unplanned Changes Resulting in a Higher Categorization – This implementation Plan incorporates by reference the section in the Implementation Plan associated with CIP-003-5 titled Planned or Unplanned Changes Resulting in a Higher Categorization.[1]

Unplanned Changes Resulting in Low Impact Categorization – This implementation Plan incorporates by reference the section in the Implementation Plan associated with CIP-003-6 titled Unplanned Changes Resulting in Low Impact Categorization. That section provides:

[1] Due to the length of that section, it is not reproduced herein.

For unplanned changes resulting in a low impact categorization where previously the asset containing BES Cyber Systems had no categorization, the Responsible Entity shall comply with all Requirements applicable to low impact BES Cyber Systems within 12 calendar months following the identification and categorization of the affected BES Cyber System.

Retirement Date

Reliability Standard CIP-003-6

Reliability Standard CIP-003-6 shall be retired immediately prior to the effective date of Reliability Standard CIP-003-7 in the particular jurisdiction in which the revised standard is becoming effective.

Current NERC Glossary of Terms of LERC and LEAP

The current definition of LERC and the term LEAP shall be retired from the NERC Glossary of Terms immediately prior to the effective date of the revised LERC term in the particular jurisdiction in which the definition is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 – Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2016-02, Modifications to CIP Standards. 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-003-7, Requirement R2	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower was assigned to this requirement. Cyber security plans enable effective implementation of the CIP standard's requirements for low impact BES Cyber Systems. The purpose of plans is for entities to develop an approach involving multiple procedures to address a broad subject matter. Using a plan, Responsible Entities can implement common controls that meet requirements for multiple high, medium, and low impact BES Cyber Systems.
FERC VRF G1 Discussion Guideline 1 - Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2 - Consistency within a Reliability Standard	This requirement calls for the Responsible Entity to implement a documented cyber security plan that contains certain sections specified in Attachment 1. The VRF is only applied at the requirement level and the Requirement Parts are treated in aggregate. While the requirement specifies a number of sections, not necessarily parts, that must be included in the cyber security plan, the VRF is reflective of the plan as a whole. Therefore, the assigned VRF of Lower is consistent with the risk impact of a violation across the entire requirement for BES assets that contain low impact BES Cyber Systems.
FERC VRF G3 Discussion Guideline 3 - Consistency among Reliability Standards	This requirement maps from CIP-003-5, Requirement R1, which has an approved VRF of Medium but applies to Cyber Assets with an inherently lower risk; therefore, the proposed VRF is consistent.
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-003-7, Requirement R2	
Proposed VRF	**Lower**
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	The cyber security plan requirement encompasses a number of subject matter areas for low impact BES Cyber Systems. The VRF is identified at the risk level represented by all of the plan areas in aggregate. Therefore, the VRF is consistent with the highest risk reliability objective contained in the requirement.

VSLs for CIP-003-7, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document cyber security awareness according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems,	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to reinforce cyber security practices at least once every 15 calendar months according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented one or more incident response plans within	The Responsible Entity documented one or more Cyber Security Incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to test each Cyber Security Incident response plan(s) at least once every 36 calendar months according to Requirement R2, Attachment 1, Section 4. (R2) OR	The Responsible Entity failed to document or implement one or more cyber security plan(s) for its assets containing low impact BES Cyber Systems according to Requirement R2, Attachment 1. (R2)

but failed to document one or more Cyber Security Incident response plans according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to update each Cyber Security Incident response plan(s) within 180 days according to Requirement R2, Attachment 1, Section 4. (R2)	its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to include the process for identification, classification, and response to Cyber Security Incidents according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document physical security controls according to	The Responsible Entity documented the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident, but failed to notify the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented electronic access controls for its assets containing low impact BES Cyber Systems, but failed to implement the electronic access controls to low impact BES Cyber Systems according to Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented the physical access controls for its assets containing low impact BES Cyber Systems, but failed to implement the physical security controls according to Requirement R2, Attachment 1, Section 2. (R2)	

	Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2)		

VSL Justifications for CIP-003-7, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously-approved Requirement R2, CIP-003-6. Therefore, the proposed VSLs do 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 VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for CIP-003-7, Requirement R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSLs are based on a single violation, and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	There is an incremental aspect to a violation of this requirement in that some measurable reliability benefit can be achieved if the Responsible Entity has documented cyber security plan(s) but fails to address one or more of the required sections of Attachment 1. A single failure of this requirement does not compromise network computer security.
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	The action of the requirement is to implement documented cyber security plan(s). Documentation of the plan(s) is required, but is not the primary objective of the requirement. Documentation is interdependent with the implementation of the plan in this case; as such, the VSL measures distance from compliance in terms of whether or not the Responsible Entity implemented all the required elements of the plan. The drafting team's intent is that this covers both documentation and implementation and, therefore, accounts for the interdependence of these tasks.

When completed, email this form to: sarcomm@nerc.com

Note: an Interpretation cannot be used to change a standard.

Interpretation 2010-xx: Request for an Interpretation of [Insert Standard Number], Requirement Rx, for [Insert Name of Company]
Date submitted: March 3, 2015 (amended May 8, 2015)
Contact information for person requesting the interpretation:
Name: Steven Parker
Organization: Energy Sector Security Consortium, Inc (EnergySec)
Telephone: 503.621.8179
Email: steve@energysec.org
Identify the standard that needs clarification:
Standard Number (include version number): CIP-002-5.1 (example: PRC-001-1)
Standard Title: Cyber Security — BES Cyber System Categorization
Identify specifically what requirement needs clarification:
Requirement Number and Text of Requirement: R1 For brevity, only relevant parts of the Requirement and Attachment 1 (incorporated by reference) are quoted here. Requirement 1, subpart 1.2 states, "Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2 …" Attachment 1 is incorporated into the requirement by reference. Attachment 1, Section 2, Criterion 2.1 states, "Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." Clarification needed: With respect to the exclusion clause of Criterion 2.1 limiting applicability, should the evaluation be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems? Stated differently, does the phrase "shared BES Cyber Systems" refer to discrete BES Cyber

Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Discussion

Criterion 2.1 introduces the concept of "shared BES Cyber Systems", but it is not clear what is meant by "shared". Additionally, Criterion 2.1 refers to such shared systems in the plural, making it unclear whether the intent was to apply the Criterion to groups of BES Cyber Systems, or simply to indicate that a single generating plant location could have multiple BES Cyber Systems that meet the Criterion.

Further adding to the uncertainty with this requirement are statements made within a NERC Lessons Learned document, "Impact Rating of Generation Resources", dated September 2, 2014. For example, the Lessons Learned document states:

> "If, for instance, the generation units and BES Cyber Systems are connected in a manner that could result in the loss of 1500 MW or more if **one or more** BES Cyber Systems at the plant were compromised or misused, then those shared BES Cyber Systems at the plant (i.e., those that can, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW) must be categorized as medium impact BES Cyber systems." (emphasis added)

In particular, the use of the phrase "one or more" suggests that a collective evaluation is required.

The aforementioned Lessons Learned document also states:

> "If a Responsible Entity adopts the segmentation approach, consistent with criterion 2.1, entities must provide evidence that BES Cyber Systems associated with any group of generating units at generating plants greater than 1500 MW are segmented effectively such that there are no **common mode vulnerabilities** that could result in the loss of 1500 MW or more of generation at a single plant." (emphasis added)

The reference to "common mode vulnerabilities" suggests that BES Cyber Systems should be evaluated as a group in some circumstances, but is unclear as "common mode vulnerabilities" is not a defined term.

The Lessons Learned document also states:

> "For example, Responsible Entities should consider physical locations that could present a single point of failure (e.g., common control rooms for multiple generating units) to determine what physical protections are appropriate."

Again, this language suggests that BES Cyber Systems may need to be evaluated in groups, for example, when multiple BES Cyber Systems are physically co-located.

The Lessons Learned document also contains a flow chart outlining a suggested process for evaluating BES Cyber Systems for impact ratings. That flow chart does not contain a process for grouping BES Cyber Systems for a collective evaluation, therefore suggesting that the impact assessment occurs individually for each discrete BES Cyber System.

A final Lessons Learned document was posted on January 29, 2015. Some of the language referred to above was removed in the final version, but the questions still remain. The final Lessons Learned document maintains the reference to the Guidelines section of the standard that refers to "BES Cyber Systems with common mode vulnerabilities". This

suggests that common mode vulnerabilities are evaluated in the context of groups of BES Cyber Systems.

In addition, the final Lessons Learned provides only two options, protecting all BES Cyber Systems at the medium level, or segmenting the units. The suggested evidence includes references to network segmentation and firewall rules. This suggests that for collections of BES Cyber Systems on a common network, the collective impact would be evaluated rather than their individual impact. Network isolation would be required to avoid this collective analysis.

On the other hand, FAQ 49, released for comment on April 1, 2015, states that a shared BES Cyber System is one that "affects two or more BES Facilities, such as multiple generation units." Likewise, FAQ 50 refers to common mode vulnerabilities as "Any systems that can affect two or more BES Facilities, such as multiple generation units. … Protection systems, fuel-handling systems, cooling water, and air systems are also examples that should be evaluated as common mode vulnerabilities." These responses support an assertion that BES Cyber Systems need only be evaluated individually.

Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard.

The evaluation of BES Cyber Systems and assignment of impact ratings is a foundational requirement in version 5 of the CIP standards. A clear understanding of the Criteria, and their proper application is essential to ensure BES Cyber Systems are correctly rated so that the appropriate controls can be applied. Furthermore, in this case, confusion regarding a potential collective assessment, and the criteria and process for such an assessment, can lead not only to under or over rating of systems, but also significant expense in re-engineering plant systems and/or security controls.

A proper understanding of this Criterion is critical to ensure entities can comply with CIP-002-5 R1 without undue risk or expense.

Version History

Version	Date	Owner	Change Tracking
1	April 22, 2011		
1	May 27, 2014	Standards Information Staff	Updated template and email address for submittal.

A. Introduction

1. Title: Cyber Security — BES Cyber System Categorization

2. Number: CIP-002-5.1

3. Purpose: To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. Applicability:

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each Special Protection System or Remedial Action Scheme where the Special Protection System or Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Interchange Coordinator or Interchange Authority

4.1.6. Reliability Coordinator

4.1.7. Transmission Operator

4.1.8. Transmission Owner

4.2. **Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each Special Protection System or Remedial Action Scheme where the Special Protection System or Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-5.1:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates:

1. **24 Months Minimum** – CIP-002-5.1 shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required CIP-002-5.1 shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

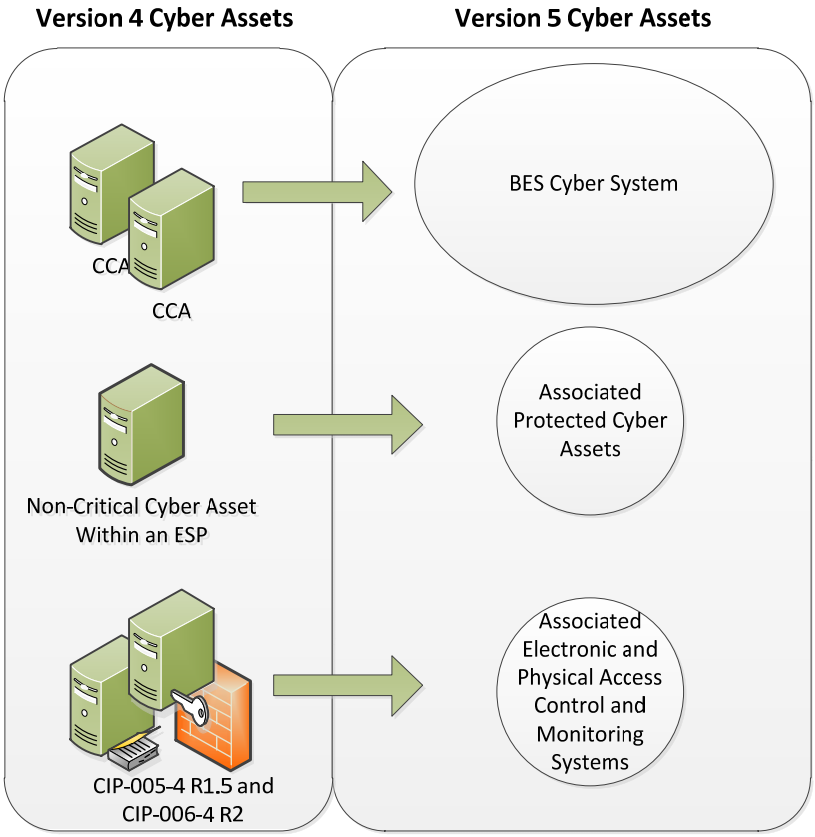
This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation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

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

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



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

Another reason for using the term "BES Cyber System" is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and

scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

Electronic Access Control or Monitoring Systems ("EACMS") – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.

Physical Access Control Systems ("PACS")– Examples include: authentication servers, card systems, and badge control systems.

Protected Cyber Assets ("PCA") – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

i. Control Centers and backup Control Centers;
ii. Transmission stations and substations;
iii. Generation resources;
iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and
vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

R2. The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority ("CEA") unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**High**	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber	Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower	Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly categorized at a lower	Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Systems, five percent or fewer high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.	category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.	category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.	Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	**Operations Planning**	**Lower**	The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1) OR The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

CIP-002-5.1 - Attachment 1

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.

1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

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

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

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

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

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

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each Special Protection System (SPS), Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

2.11. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

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

2.13. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating (L)

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. Special Protection Systems that support the reliable operation of the Bulk Electric System.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-5.1

CIP-002-5.1 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber

Systems that would be subject to CIP-002-5.1. The concept includes a number of named BES reliability operating services. These named services include:

Dynamic Response to BES conditions
Balancing Load and Generation
Controlling Frequency (Real Power)
Controlling Voltage (Reactive Power)
Managing Constraints
Monitoring & Control
Restoration of BES
Situational Awareness
Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
  - Providing actual reserve generation when called upon (GO,GOP)
  - Monitoring that reserves are sufficient (BA)
- Governor Response
  - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
  - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
  - Zone protection for breaker failure (DP, TO, TOP)
  - Breaker protection (DP, TO, TOP)
  - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- Special Protection Systems or Remedial Action Schemes
  - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
  - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
  - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
  - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
  - Software used to perform calculation (BA)
- Demand Response
  - Ability to identify load change need (BA)
  - Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding
  - Ability to identify load change need (BA)
  - Ability to implement load changes (TOP, DP)

- Non-spinning reserve (contingency reserve)
  - Know generation status, capability, ramp rate, start time (GO, BA)
  - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
  - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
  - Software to calculate unit adjustments (BA)
  - Transmit adjustments to individual units (GOP)
  - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
  - Frequency source, schedule (BA)
  - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
  - Sensors, stator control system, feedback (GO)
- Capacitive resources
  - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
  - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
  - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
  - SCADA (TOP, GOP)
  - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
  - Through black start units (TOP, GOP)
  - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA,TOP,GOP,RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

- When the drafting team uses the term "Facilities", there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.
- In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.
- It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating (H)

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some

of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.

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

Medium Impact Rating (M)

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

  In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

  By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

  If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

  The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

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

- Criterion 2.9 categorizes BES Cyber Systems for Special Protection Systems and Remedial Action Schemes as medium impact. Special Protection Systems and Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.

- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.

- Criterion 2.13 categorizes as medium impact those BA Control Centers that "control" 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

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

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.

- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the

backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the "Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface." This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:

    - Excluded radial facilities that would only provide support for single generation facilities.

    - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

  The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

  Additionally, in NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:

    - 230 kV –> 700 MVA

    - 345 kV –> 1,300 MVA

    - 500 kV –> 2,000 MVA

    - 765 kV –> 3,000 MVA

  In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

    - For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities

would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.

- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.

- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as

specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.

- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.

- Criterion 2.9 designates as medium impact those BES Cyber Systems for those Special Protection Systems (SPS), Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.

- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

  This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric

System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource ("LaaR") Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that "control" 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating (L)

BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

  In response, the CIP Version 5 drafting team sought informal input from NERC's Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

  The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to

restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

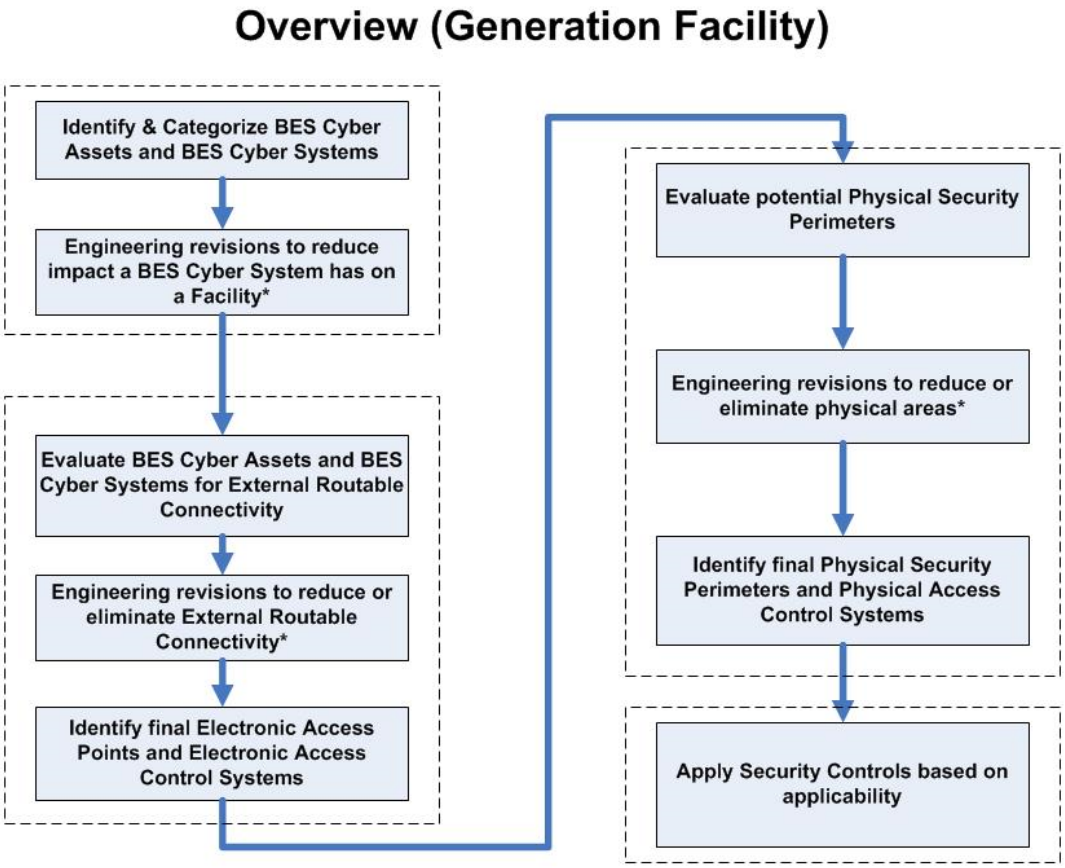
Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

  Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.



* - Engineering revisions will need to be reviewed for cost justification, operational\safety requirements, support requirements, and technical limitations.

Rationale:

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

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of "bright-line" criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager's approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3.	Update

		Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1. (Order becomes effective on 2/3/14.)	

Appendix 1

Interpretation of CIP-002-5.1, Requirement R1, Attachment 1, Criterion 2.1

Requirement Number and Text of Requirement
CIP-002-5.1, Requirement R1 R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: i. Control Centers and backup Control Centers; ii. Transmission stations and substations; iii. Generation resources; iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements; v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above. 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset; 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required). Attachment 1, Criterion 2.1 2. Medium Impact Rating (M) Each BES Cyber System, not included in Section 1 above, associated with any of the following: 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase "shared BES Cyber Systems."

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase "shared BES Cyber Systems" means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase "shared BES Cyber Systems," means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states "Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2…" Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states "*Each BES Cyber System*…associated with any of the following [criteria]." (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that "[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System." The Background section also provides:

> The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term "shared" is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

> Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." For criterion 2.2: "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual

VERSION ~~3~~ TBD

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 to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. 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.

- **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,*

[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.

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 provincial government of 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.

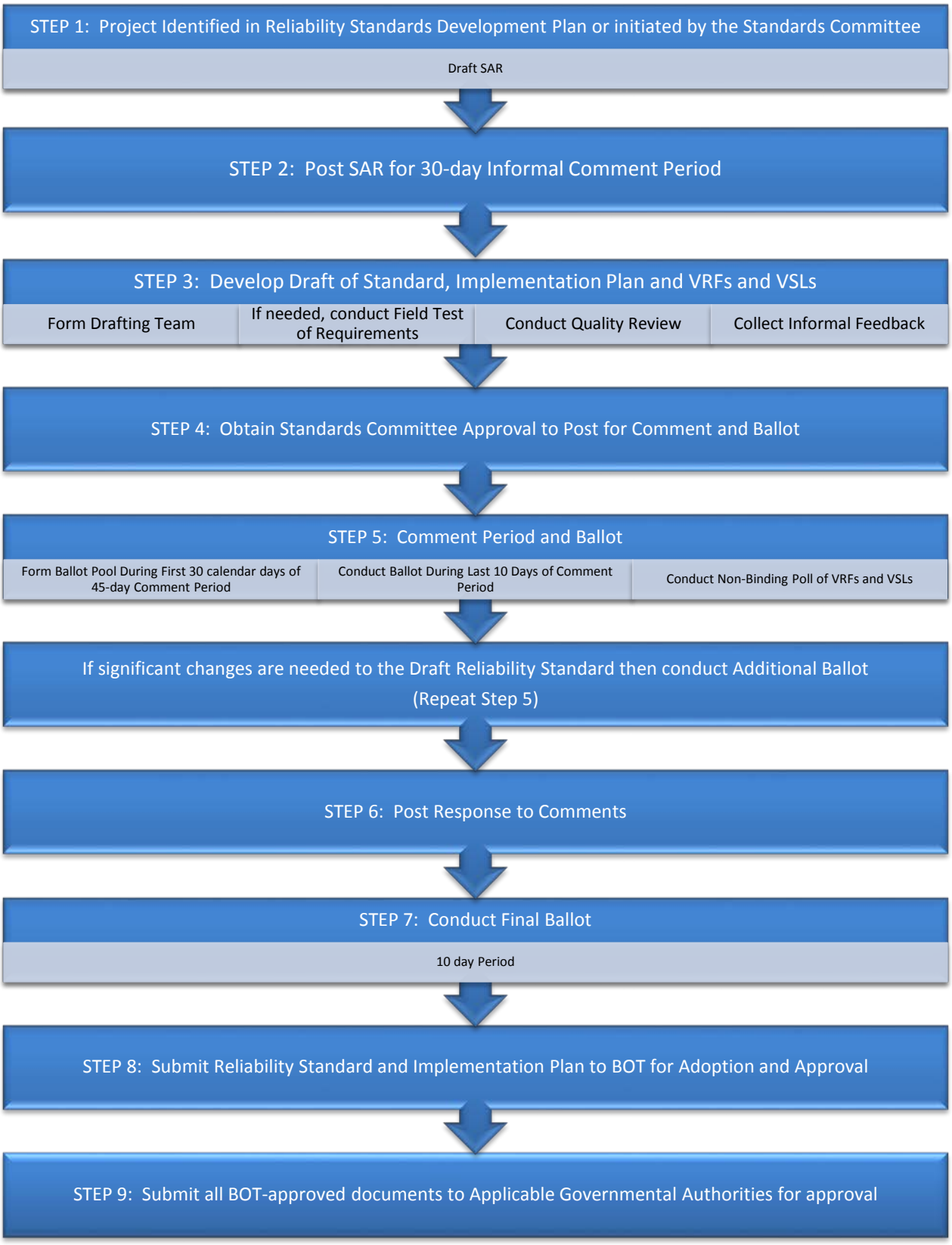


FIGURE 1: Process for Developing or Modifying a Reliability Standard

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 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.

6.1: Field Tests and Data Analysis for Validation of Concepts(collectively "Field Test")

1. Field tTests or collection and analysis of data to validate concepts that support the development of Requirements should be conducted before the SAR Standard Authorization Request ("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.
2. To conduct a Field Test of a technical concept in a proposed new or revised Reliability Standard, the requesting team must work with NERC staff to identify one of NERC's technical committees to lead the effort in conducting the Field Test.

6.1.1: Field Test Approval

The request to conduct a Field Test must include, at a minimum:

- the Field Test plan,
- the implementation schedule, and
- an expectation for periodic updates of the analysis of the results.

Prior to the requesting team conducting a Field Test, it must:

- first receive approval from the lead NERC technical committee, and
- subsequently receive approval from the Standards Committee.

6.1.2: Field Test Suspension

During the Field Test, if the lead NERC technical committee overseeing the Field Test determines there is a reliability risk to the BES:

- 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 shall notify NERC compliance staff to coordinate any compliance related issues such as continuance or cessation of waivers.

Prior to the Field Test being restarted after it has been stopped, the requesting team must resubmit the Field Test and receive approval as outlined in section 6.1.1.

If the Field Test does not provide sufficient information to formulate a conclusion within the time allotted in the plan, the Chair of the Standards Committee will work with the requesting team and the lead NERC technical committee to determine whether to continue, modify or terminate the Field Test.

If ~~a drafting team finds that it~~ the requesting team determines a need~~s~~ to ~~collect and analyze data or~~ conduct a ~~field~~ Field ~~test~~ Test of a concept that was not identified ~~when~~ in 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~~it must create a supplemental SAR to include the Field Test and receive approval as outlined in section 6.1.1.

~~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.~~3~~2: 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 requesting team may request waivers of compliance for Field Test participants that would be rendered ~~render Registered Entities~~ incapable of complying with the ~~current~~ Requirement(s) of ~~an approved~~the 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 t~~The Compliance Monitoring and Enforcement Program staff ~~prior to the approval of the field test or data collection and analysis~~shall determine whether to approve the requested waivers, and the 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

[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.~~

NERC Board of the pending Field Test, the expected duration, and any requested waivers from compliance for registered entities.

During the Field Test, the requesting team conducting the Field Test shall provide periodic updates (no less than quarterly) on the progress of the Field Tests to the Standards Committee and the applicable NERC technical committees. The Chair of the Standards Committee shall keep the NERC Board 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 Reliability Standards 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.

An Interpretation may only clarify or interpret the Requirements of an approved Reliability Standard, including, if applicable, any attachment referenced in the Requirement being clarified. No other elements of an approved Reliability Standard are subject to 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 Staffs shall review the request for interpretation to determine whether it meets the requirements for a valid interpretation. Based on this review, the NERC Standards and Legal Staffs shall make a recommendation to the Standards Committee whether to accept the request for Interpretation and move forward in responding to the Interpretation request.

For example, an Interpretation request may be rejected where it:

(1) Requests approval of a particular compliance approach;
(2) Identifies a gap or perceived weakness in the approved Reliability Standard;
(3) Where an issue can be addressed by an active standard drafting team;
(4) Where it requests clarification of any element of a Reliability Standard other than a Requirement;
(5) Where a question has already been addressed in the record;
(6) Where the Interpretation 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 seeks to expand the scope of a Reliability Standard; or
(8) Where the meaning of a Reliability Standard is plain on its face.

If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the Interpretation to the entity requesting the Interpretation within 10 business days of the decision to reject. If the Standards Committee accepts the Interpretation request, the NERC Standards Staff shall (i) form a ballot pool and (ii) assemble an Interpretation drafting team with the relevant expertise to address the interpretation for approval by the Standards Committee. As soon as practical, the team shall develop a "final draft" Interpretation providing the requested clarity.

Interpretations will be balloted in the same manner as Reliability Standards.

[26] The *Request for Interpretation* form is posted on the NERC Standards web page.

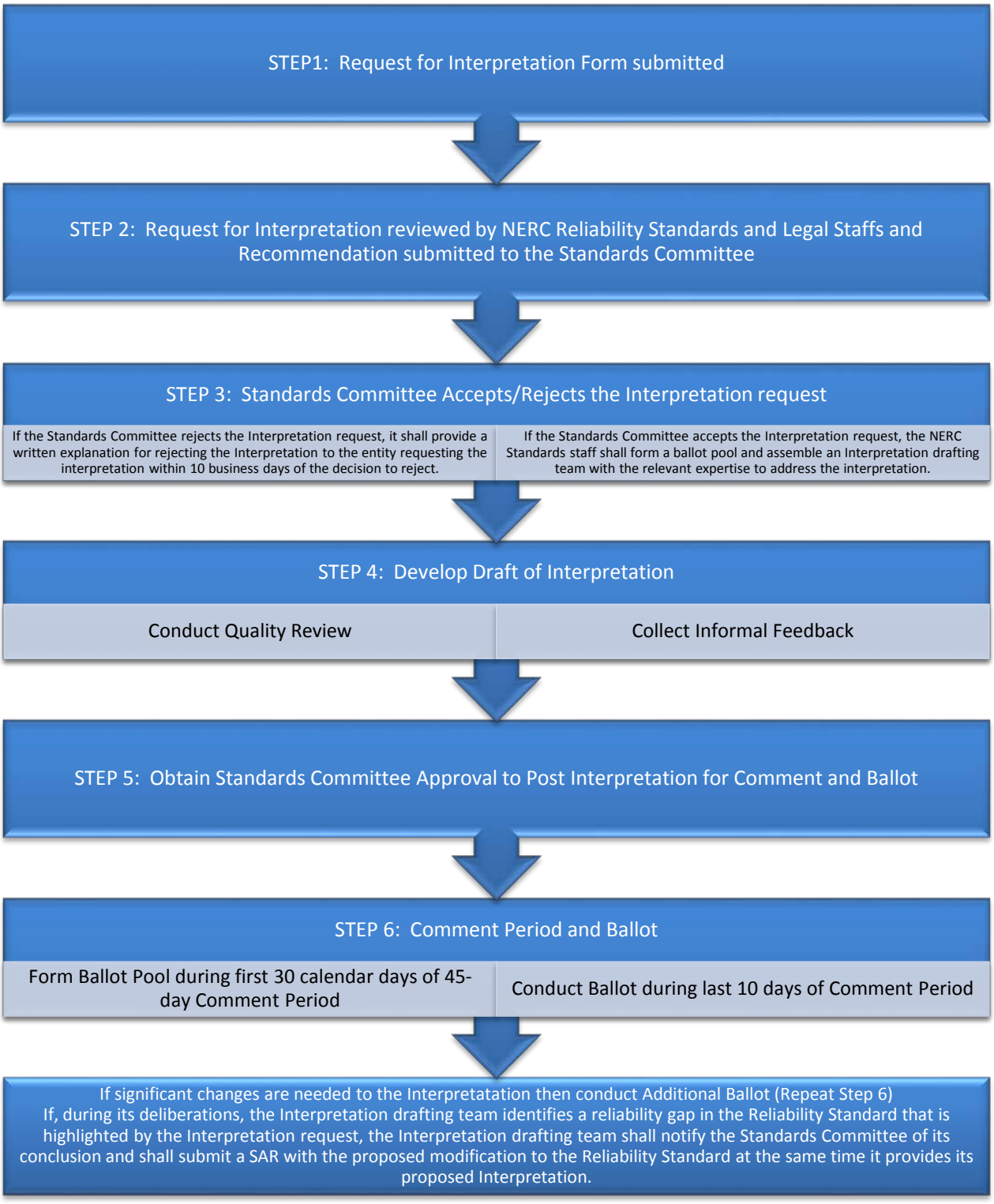
If stakeholder comments indicate that there is not a consensus for the Interpretation, and the Interpretation drafting team cannot revise the Interpretation without violating the basic expectations outlined above, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with the proposed modification to the Reliability Standard. The entity that requested the Interpretation shall be notified and the disposition of the Interpretation shall be posted.

If, during its deliberations, the Interpretation drafting team identifies a reliability gap 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 at the same time it provides its proposed Interpretation.

The NERC Reliability Standards and Legal Staffs shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation. 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.[27] If an Interpretation drafting team proposes 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 at the time the Interpretation is submitted for adoption. Following adoption by the Board of Trustees, NERC Staff shall file the Interpretation for approval by Applicable Governmental Authorities and the Interpretation shall become effective when approved by those Applicable Governmental Authorities. 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.

[27] 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 Standards staff shall form a ballot pool and assemble an Interpretation drafting team with the relevant expertise to address the interpretation.
STEP 4: Develop Draft of Interpretation
Conduct Quality Review
Collect Informal Feedback
STEP 5: Obtain Standards Committee Approval to Post Interpretation for Comment and Ballot
STEP 6: Comment Period and Ballot
Form Ballot Pool during first 30 calendar days of 45-day Comment Period
Conduct Ballot during last 10 days of Comment Period
If significant changes are needed to the Interpretatation then conduct Additional Ballot (Repeat Step 6)
If, during its deliberations, the Interpretation drafting team identifies a reliability gap 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 at the same time it provides its proposed Interpretation.

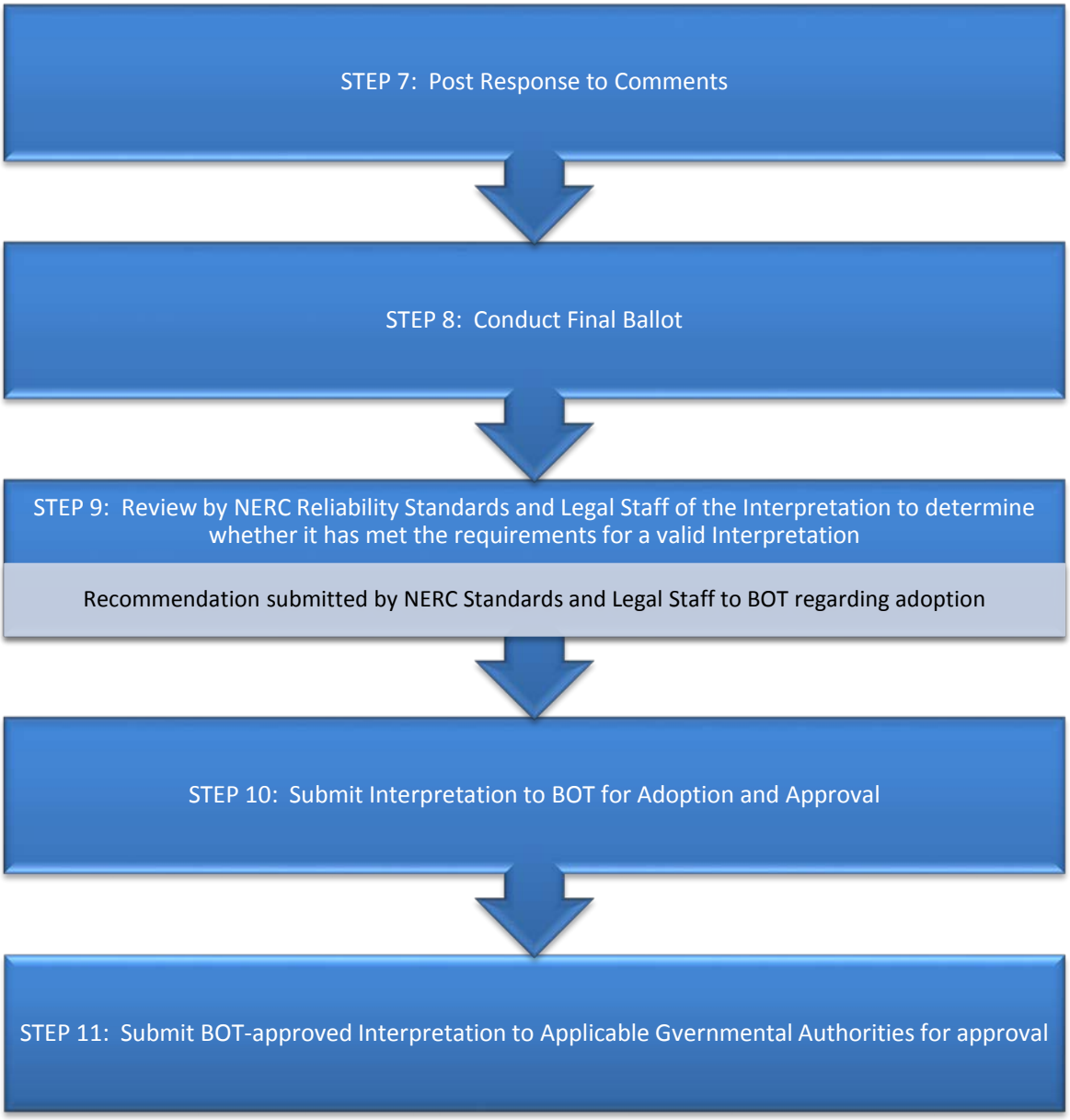


FIGURE 2: Process for Developing an Interpretation

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.

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.

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[28] 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

[28] 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.[29]

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

[29] 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.[30] 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.

[30] 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

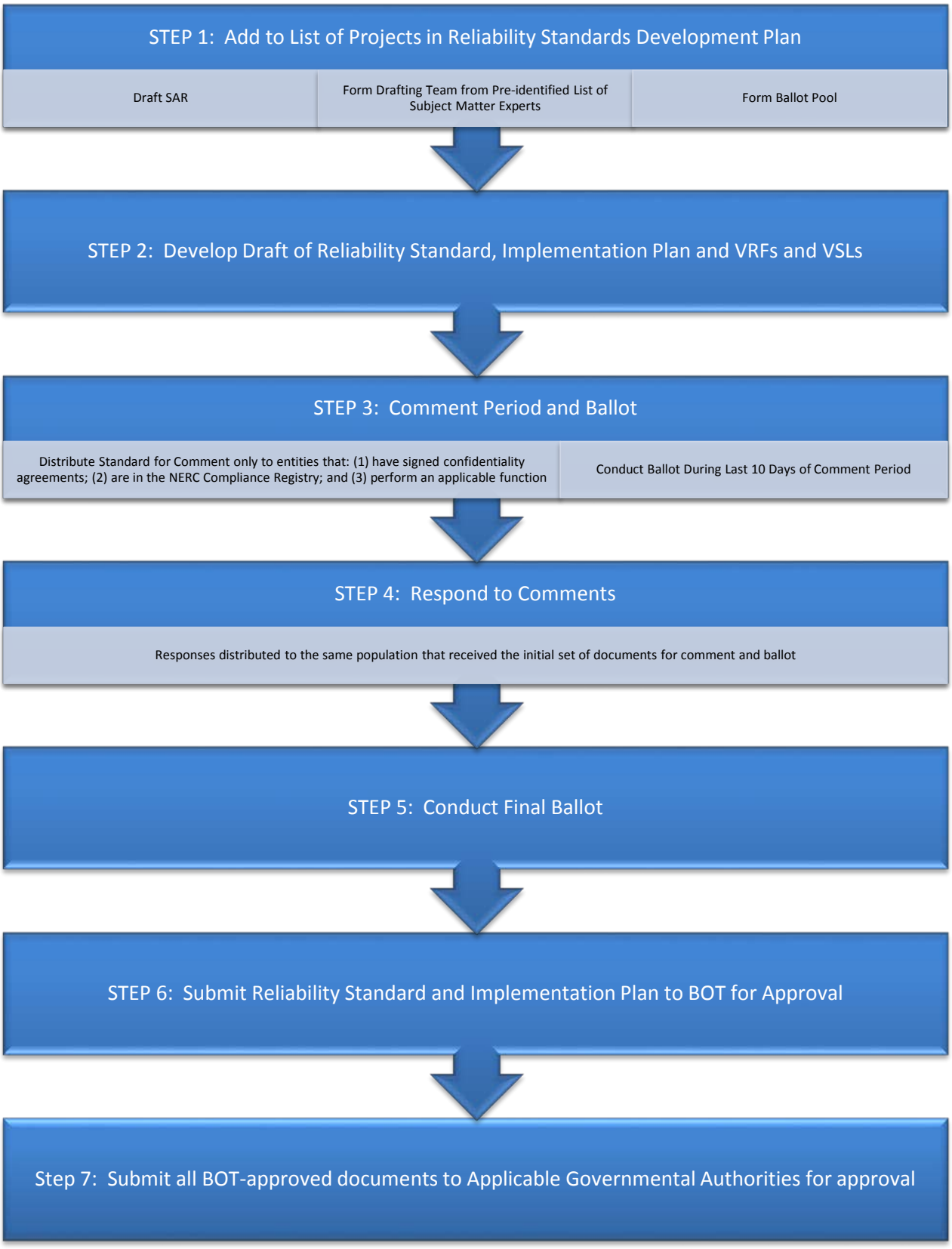


FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

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.[31] 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.

[31] 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

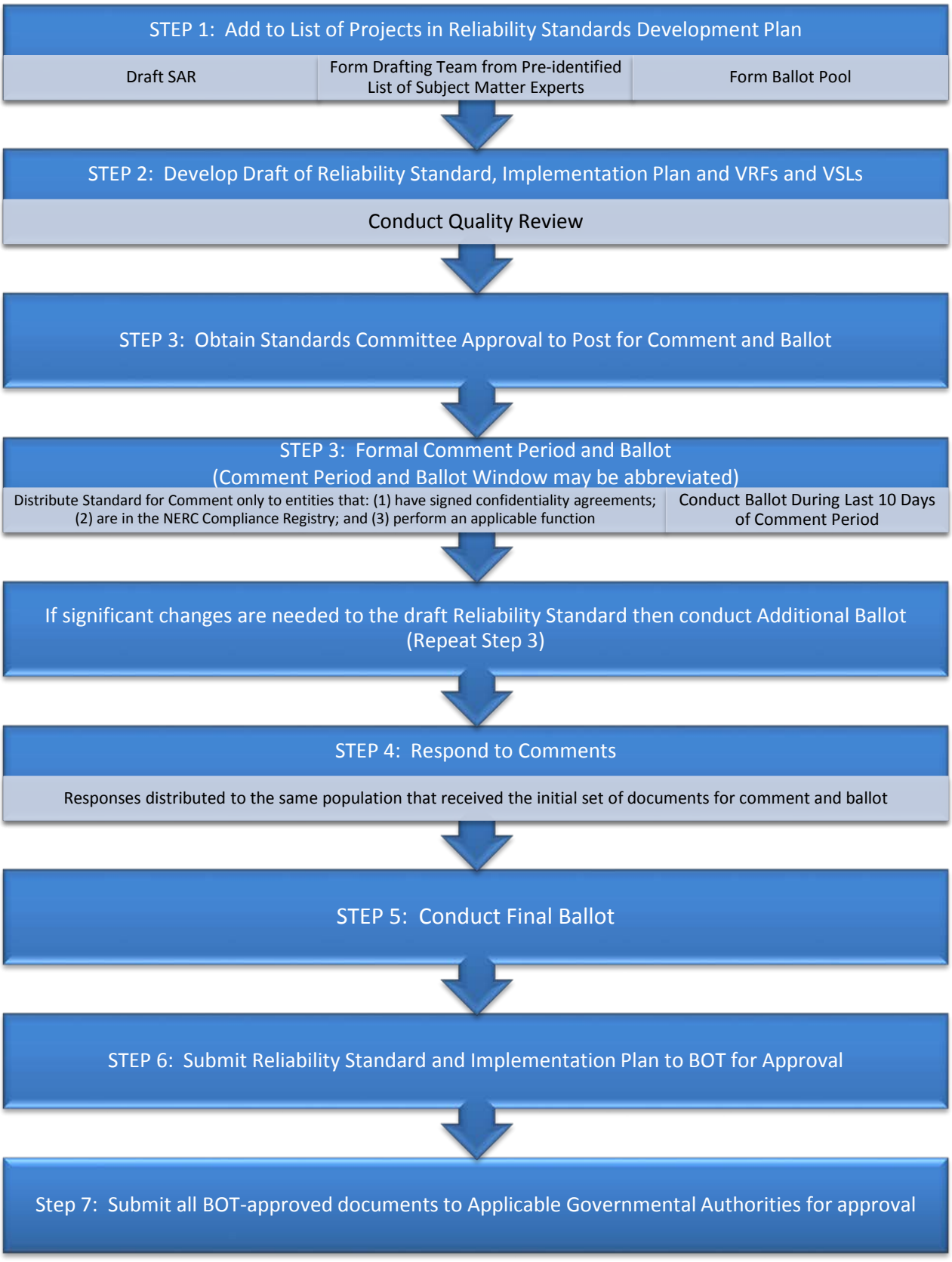


FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

Section 11.0: Process for Approving Supporting Documents

The 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 documents may explain or facilitate implementation 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.

The Standards Committee shall authorize the posting of all supporting references[32] 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 that the document has had stakeholder review to verify the accuracy of the technical content. 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.

Type of Document	Description
Reference	Descriptive, technical information or analysis or explanatory information to support the understanding and interpretation of a 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.
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.
White Paper	An informal paper stating a position or concept. A white paper may be used to propose preliminary concepts for a Reliability Standard or one of the documents above.

[32] The Standards Committee's Procedure for Approving the Posting of Reference Documents is posted on the Reliability Standards Resources web page.

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.[33] 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.

[33] 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 Standard Processes Manual

Appendix 3A to the NERC Rules of Procedure
Section 6.0, Processes for Conducting Field Tests | September 2015

Revisions are proposed to Section 6, *Processes for Conducting Field Tests and Collecting and Analyzing Data*, of the NERC Standard Processes Manual (SPM), Appendix 3A to the NERC Rules of Procedure. Under Section 6.0 of the SPM, field tests may be used to analyze data and validate concepts in the development of Reliability Standards. Changes are proposed to develop a more concise process for conducting field tests, to clarify oversight and authority over the technical aspects of field tests, and to increase coordination across the Standards Committee (SC) and the NERC technical committee overseeing the field test when field tests are conducted.

A redline of the proposed changes is available on the Revisions to the NERC SPM page.

The proposed revisions are posted for a 30-day informal comment period from September 29, 2015 through October 28, 2015. All comments should be submitted through the NERC Standards Balloting and Commenting System (SBS).

Background

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.

Summary of Proposed Revisions

The proposed revisions are summarized as follows:

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). Two new subsections are created:

> Proposed Section 6.1.1 summarizes, in bullet form, 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.

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 Electric System (BES). 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 6.2 clarifies the processes governing communication and coordination for all types of 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 keeping the NERC Board of Trustees informed of pending and ongoing field tests, including any requested compliance waivers.

Next Steps

NERC staff will consider all comments received during the comment period and determine next steps.

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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.

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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.

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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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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-004-4 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015

Anticipated Actions	Date
45-day formal comment period with ballot	07/25/2016 – 09/08/2016
45-day formal comment period with additional ballot	09/26/2016 – 11/09/2016
10-day final ballot	12/01/2016 – 12/12/2016
NERC Board (Board) adoption	February 2017

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.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Event Reporting

2. **Number:** EOP-004-4

3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as "Responsible Entity."

   4.1.1. Reliability Coordinator

   4.1.2. Balancing Authority

   4.1.3. Transmission Owner

   4.1.4. Transmission Operator

   4.1.5. Generator Owner

   4.1.6. Generator Operator

   4.1.7. Distribution Provider

5. **Effective Date:** See the Implementation Plan for EOP-004-4.

~~**6. Background:** NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:~~

~~1. CIP-001 could be merged with EOP-004 to eliminate redundancies.~~
~~2. Acts of sabotage have to be reported to the DOE as part of EOP-004.~~
~~3. Specific references to the DOE form need to be eliminated.~~
~~4. EOP-004 had some 'fill-in-the-blank' components to eliminate.~~

~~The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.~~

~~The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.~~

~~The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the "road map" that will be used by the DSR SDT in~~

~~updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.~~

~~**7. Standard-Only Definition:** None~~

B. Requirements and Measures

~~**Rationale for Requirement R1:** Text~~

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-~~2 3~~ 4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-~~3~~4 Attachment 1 and in accordance with the entity responsible for reporting.

~~**Rationale for Requirement R2:** Text~~

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday~~ local time~~). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Each Responsible Entity will have as evidence of reporting an event either a~~,~~ copy of the completed EOP-004-~~3~~ 4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday~~ local time~~). ~~(R2)~~

~~Rationale for Requirement R3:~~ ~~Text~~

~~**R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)~~

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 Responsible 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 following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement~~s~~ R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement~~s~~ R2~~, R3~~ and Measure M2~~, M3~~.

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 duration specified above, whichever is longer.

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

1.3. Compliance Monitoring and Enforcement Program

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

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.

R #	Violation Severity Levels			
				OR The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.
~~R3.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.~~ ~~OR~~ ~~The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.~~ ~~OR~~ ~~The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.~~ ~~OR~~ ~~The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.~~ ~~OR~~ ~~The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.~~

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: -systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Generation loss: The EOP SDT discussed dispersed power producing resources and their generation loss due to weather patterns or fuel source unavailability, but NERC confirmed that reporting of generation loss would be used to report Forced Outages not weather patterns or fuel source unavailability for these resources.

Complete loss of Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information."

Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control at a BES control center for 30 continuous minutes or more" provides clarity to the "Threshold for Reporting" and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of ~~a~~ its Facility	~~BA,~~ TO, ~~TOP,~~ GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to ~~a~~ its Facility	~~BA,~~ TO, ~~TOP,~~ GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at ~~a~~ its Facility. ~~Do not report theft unless it degrades normal operation of a Facility.~~
Physical threats to ~~a~~ its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at ~~a~~ its BES control center.
~~BES Emergency requiring public~~ Public appeal for load reduction	~~Initiating entity is responsible for reporting~~BA	~~Public appeal for load reduction event.~~Public appeal for load reduction to maintain continuity of the BES.
~~BES Emergency requiring system~~System-wide voltage reduction to maintain the continuity of the BES	~~Initiating entity is responsible for reporting~~TOP	System wide voltage reduction of 3% or more.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
~~BES Emergency requiring manual f~~Firm load shedding resulting from a BES Emergency	~~Initiating entity is responsible for reporting~~RC, BA, TOP	~~Manual firm~~ Firm load shedding ≥ 100 MW.
~~BES Emergency resulting in automatic firm load shedding~~	~~DP, TOP~~	~~Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).~~
BES Emergency resulting in ~~Voltage~~ voltage deviation on a Facility	TOP	~~Observed within its area a~~ A voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.
~~IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)~~	~~RC~~	~~Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).~~
Uncontrolled ~~Loss~~ loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled ~~Loss~~ loss of firm load for ≥ 15 Minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA~~, GOP~~	Total generation loss, within one minute, of~~-~~: ≥ 2,000 MW ~~for entities~~ in the Eastern, ~~or~~ Western, or Quebec Interconnection OR ≥ 1,000 MW ~~for entities~~ in the ERCOT ~~or Quebec~~ Interconnection
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).
Unplanned BES control center evacuation	RC, BA, TOP	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.
Complete loss of ~~voice communication~~Interpersonal Communication capability at a BES control center	RC, BA, TOP	Complete loss of ~~voice~~ Interpersonal ~~communication~~ Communication capability affecting a staffed BES control center for 30 continuous minutes or more.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of monitoring or control capability at a BES control center	RC, BA, TOP	Complete loss~~Complete loss~~ of monitoring or control at ~~capability affecting~~ a BES control center for 30 continuous minutes or more. ~~such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.~~

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
Task		**Comments**
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No☐ Unknown ☐
4.	**Event Identification and Description:**	

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."	
Task	**Comments**
(Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical Threat to ~~a~~ its Facility ☐ Physical Threat to ~~a~~ its BES control center ☐ Unplanned BES control center evacuation ☐ Public appeal for load reduction ☐ System-wide voltage reduction ☐ BES Emergency: ~~☐ public appeal for load reduction~~ ~~☐ system-wide voltage reduction~~ ☐ ~~manual~~ firm load shedding ☐ ~~automatic firm load shedding~~voltage deviation on a Facility ☐ uncontrolled loss of firm load ~~☐ Voltage deviation on a Facility~~ ~~☐ IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer~~	Written description (optional):

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."	
Task	**Comments**
~~Paths (WECC only)~~ ☐ ~~Loss of firm load~~ ☐ System separation ☐ Generation loss ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss ☐ ~~unplanned~~ Unplanned BES control center evacuation ☐ Complete loss of ~~voice~~ Interpersonal ~~communication~~ Communication capability at a BES control center ☐ Complete loss of monitoring or control capability at a BES control center	

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	

Guideline and Technical Basis

~~**Distribution Provider Applicability Discussion**~~

~~The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the "Threshold for Reporting" for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more that 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.~~

Multiple Reports for a Single Organization

For entities that have multiple registrations, the ~~DSR SDT intends~~requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

~~**Summary of Key Concepts**~~

~~The DSR SDT identified the following principles to assist them in developing the standard:~~

- ~~Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System~~
- ~~Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements~~
- ~~Establish clear criteria for reporting~~
- ~~Establish consistent reporting timelines~~
- ~~Provide clarity around who will receive the information and how it will be used~~

~~During the development of concepts, the DSR SDT considered the FERC directive to "further define sabotage". There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to reporting events. The term "sabotage" is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events~~

~~as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.~~

~~The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.~~

~~The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.~~

~~**Data Gathering**~~

~~The requirements of EOP-004-1 require that entities "promptly analyze Bulk Electric System disturbances on its system or facilities" (Requirement R2). The requirements of EOP-004-3 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-3 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.~~

Law Enforcement Reporting

The reliability objective of EOP-004-~~3~~ 4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC

- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

~~**Present expectations of the industry under CIP-001-1a:**~~

~~It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have led to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.~~

~~**Coordination of Local and State Law Enforcement Agencies with the FBI**~~

~~The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.~~

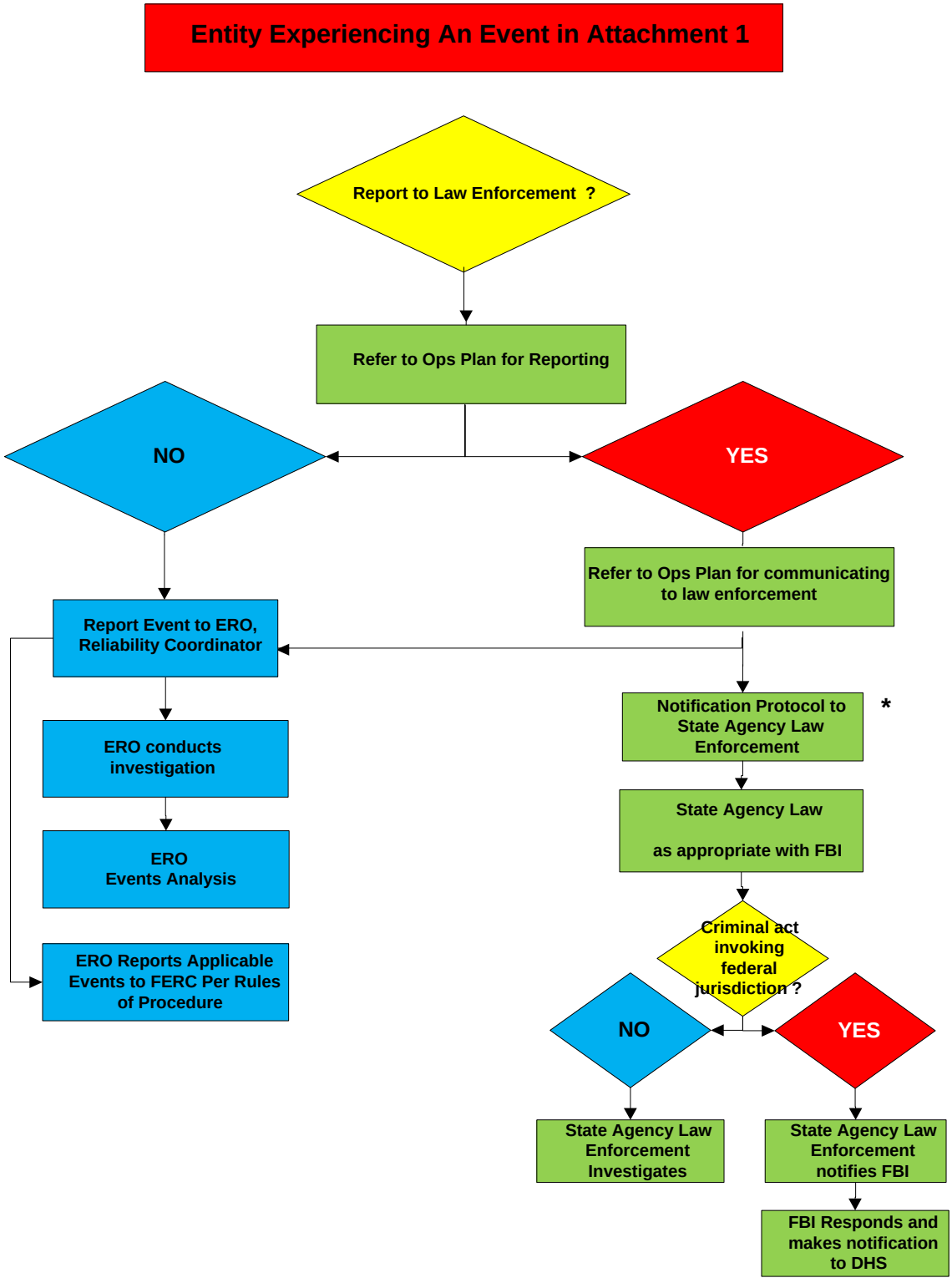
~~**Coordination of Local and Provincial Law Enforcement Agencies with the RCMP**~~

~~A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).~~

~~**A Reporting Process Solution – EOP-004**~~

~~A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.~~

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

CIP-001 — Sabotage Reporting

EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

Summary of Concepts and Assumptions:

The Standard:

- Requires reporting of "events" that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

Discussion of Disturbance Reporting

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.
3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and

~~developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).~~

~~*Discussion of Event Reporting*~~

~~There are situations worthy of reporting because they have the potential to impact reliability.~~

~~Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.~~

~~Examples of such events include:~~

~~Bolts removed from transmission line structures~~

~~Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)~~

~~Destruction of Bulk Electric System equipment~~

~~**What about sabotage?**~~

~~One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *". . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event."*~~

~~Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.~~

~~Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.~~

Potential Uses of Reportable Information

General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information as known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination

of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

~~Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.~~

~~**Collection of Reportable Information or "One stop shopping"**~~

~~The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.~~

~~The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.~~

~~ill assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.~~

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 adoption, the text from the rationale text boxes was moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-004-4 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015

Anticipated Actions	Date
45-day formal comment period with ballot	07/25/2016 – 09/08/2016
45-day formal comment period with additional ballot	09/26/2016 – 11/09/2016
10-day final ballot	12/01/2016 – 12/12/2016
NERC Board (Board) adoption	February 2017

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.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Event Reporting

2. **Number:** EOP-004-4

3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as "Responsible Entity."

   4.1.1. Reliability Coordinator

   4.1.2. Balancing Authority

   4.1.3. Transmission Owner

   4.1.4. Transmission Operator

   4.1.5. Generator Owner

   4.1.6. Generator Operator

   4.1.7. Distribution Provider

5. **Effective Date:** See the Implementation Plan for EOP-004-4.

B. Requirements and Measures

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-4 Attachment 1 and in accordance with the entity responsible for reporting.

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Each Responsible Entity will have as evidence of reporting an event either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday).

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 Responsible 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 following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement R2 and Measure M2.

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 duration specified above, whichever is longer.

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

1.3. Compliance Monitoring and Enforcement Program

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

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Generation loss: The EOP SDT discussed dispersed power producing resources and their generation loss due to weather patterns or fuel source unavailability, but NERC confirmed that reporting of generation loss would be used to report Forced Outages not weather patterns or fuel source unavailability for these resources.

Complete loss of Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information."

Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control at a BES control center for 30 continuous minutes or more" provides clarity to the "Threshold for Reporting" and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of its Facility	TO, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to its Facility	TO, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.
Physical threats to its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at its BES control center.
Public appeal for load reduction	BA	Public appeal for load reduction to maintain continuity of the BES.
System-wide voltage reduction to maintain the continuity of the BES	TOP	System wide voltage reduction of 3% or more.
Firm load shedding resulting from a BES Emergency	RC, BA, TOP	Firm load shedding ≥ 100 MW.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
BES Emergency resulting in voltage deviation on a Facility	TOP	A voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.
Uncontrolled loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled loss of firm load for ≥ 15 Minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA	Total generation loss, within one minute, of: ≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR ≥ 1,000 MW in the ERCOT Interconnection
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).
Unplanned BES control center evacuation	RC, BA, TOP	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.
Complete loss of Interpersonal Communication capability at a BES control center	RC, BA, TOP	Complete loss of Interpersonal Communication capability affecting a staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at a BES control center	RC, BA, TOP	Complete loss of monitoring or control at a BES control center for 30 continuous minutes or more.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
Task		**Comments**
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No☐ Unknown ☐
	Event Identification and Description:	

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
Task		**Comments**
4.	(Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical Threat to its Facility ☐ Physical Threat to its BES control center ☐ Unplanned BES control center evacuation ☐ Public appeal for load reduction ☐ System-wide voltage reduction ☐ BES Emergency: ☐ firm load shedding ☐ voltage deviation on a Facility ☐ uncontrolled loss of firm load ☐ System separation ☐ Generation loss ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss	Written description (optional):

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
Task		**Comments**
	☐ Unplanned BES control center evacuation ☐ Complete loss of Interpersonal Communication capability at a BES control center ☐ Complete loss of monitoring or control capability at a BES control center	

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	

Guideline and Technical Basis

Multiple Reports for a Single Organization

For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

Law Enforcement Reporting

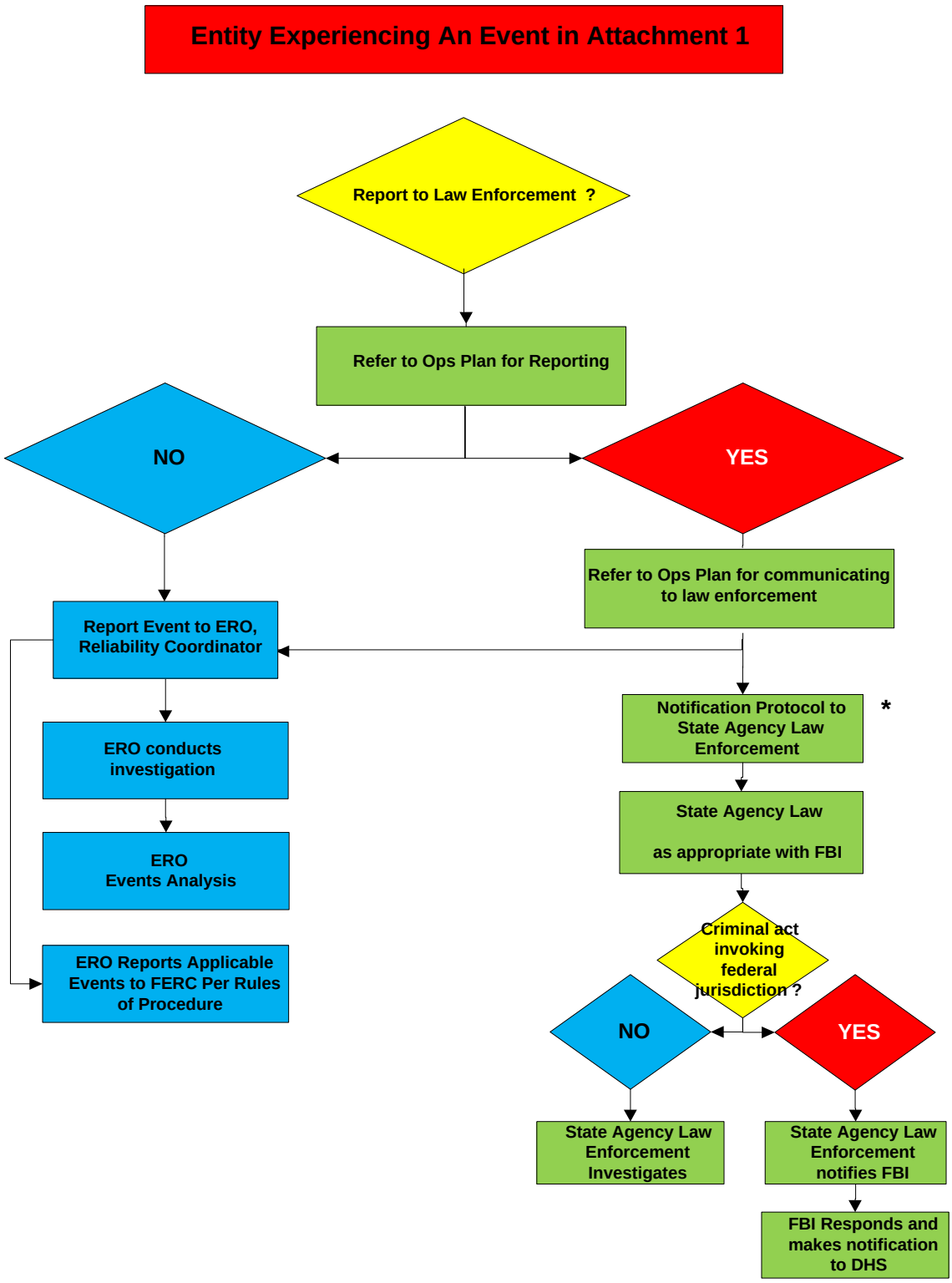
The reliability objective of EOP-004-4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Potential Uses of Reportable Information

General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information as known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

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 adoption, the text from the rationale text boxes was moved to this section.

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Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standard EOP-004-4

Applicable Standard(s)

- EOP-004-4 — Event Reporting

Requested Retirement(s)

- EOP-004-3 — Event Reporting

Prerequisite Standard(s)

None.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Owner
- Generator Owner
- Transmission Operator
- Generator Operator
- Distribution Provider

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standard making the standard more Results-based.

Effective Date

EOP-004-4 — Event Reporting

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 twelve (12) 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 twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition
None.

Retirement Date

EOP-004-3 — Event Reporting
Reliability Standard EOP-004-3 shall be retired immediately prior to the effective date of EOP-004-4 in the particular jurisdiction in which the revised standard is becoming effective.

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Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-03, Requirement R3 **R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*	Recommended for retirement.	The EOP SDT recommends retirement of Requirement R3 under Criterion B1, administrative; the R3 requirement in EOP-004-3 requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome. Contact lists are administrative in nature.

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-004-4 – Event Reporting**. 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 by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

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. A planning requirement that is administrative in nature.

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 EOP-004-4, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time frame to have an event reporting Operating Plan. The assignment of the Lower VRF was made based on the premise that failure to have an event reporting Operating Plan would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an event reporting Operating Plan that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective, which is to have an event reporting Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-004-4, R1			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

VRF Justifications for EOP-008-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event operating plan Operating Plan and mirrors the Requirements of EOP-004-3 with some minor edits. The VSL's for R1 were not revised. The VSL's for this requirement meet 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	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed 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 similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-004-4, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in Operations Assessment time frame that requires entities to report events per their Operating Plan. 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. .
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the entity to report events per their Operating Plan. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned, so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 uses similar language from EOP-004-3, Requirement R2, and the VRF remains unchanged from earlier versions.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to report events per the Operating Plan would not be expected to have an adverse impact on the bulk power system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-004-4, R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.

VSL Justifications for EOP-004-4, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event reporting Operating Plan and reporting events, and Requirement 2 language of EOP-004-4 is only slightly changed from EOP-004-3. The VSL's for this requirement meet 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	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The proposed 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 similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-004-4, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

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%			

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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%			

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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%			

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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		

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
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			

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
483	Project 2014-02	RICHTHML 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-009 Yes CIP-010 Yes CIP-011 Yes Definitions Yes Support--7/14/14		
484	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Final Ballot	7/16/2014	7/25/2014	Quorum: 78.92% Approval: 58.88%	Support--7/23/14		
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.49%/80.15%/80.00%/80.83%/80.36% Approval: 91.38%/92.20%/89.51%/90.58%/87.09%	Support--7/24/14	Affirmative	
486	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 82.67% Approval: 55.77%		Affirmative	
487	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Initial Ballot	7/29/2014	8/7/2014	Quorum: 76.37% Approval: 76.91%		Affirmative	
488	Project 2012-13	Project 2009-03 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.66% Approval: 42.27%	Negative--8/14/14	Negative	
489	Project 2014-01	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.94% Approval: 79.75%	Support	Affirmative	
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 85.32%/86.01% Approval: 95.35%/95.86%	Support	Affirmative	
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and	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		

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
1.	N/A	Standards Project Prioritization Reference Document and Tool	Project Prioritization Tool		1/21/11	2/10/11	Yes 2/10/11
2.	Project 2007-23	Project 2007-23 - Violation Severity Levels	VSLs		1/20/11	2/18/11	Yes 2/18/11
3.	N/A	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	CAN-0015 Unavailability of NERC Tools		2/4/11	2/18/11	Yes 2/18/11
4	N/A	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	CAN-0016 CIP-001-1, R1		2/4/11	2/18/11	Yes 2/18/11
5.	N/A	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	CAN-0018 FAC-008, R.1.2.1		2/4/11	2/18/11	Yes 2/18/11
6.	Regional Standard	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		1/10/11	2/24/11	
7.	Project 2007-07	Project 2007-07 - Vegetation Management - FAC-003	FAC-003-2		1/27/11	2/28/11	Yes 2/28/11
8.	N/A	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	CAN-0017 CIP-007, R5		2/11/11	3/4/11	Yes 3/4/11
9.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1		2/4/11	3/7/11	Yes 3/7/11
10.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	COM-001 COM-002 IRO-001 IRO-014		1/18/11	3/7/11	Yes 3/7/11
11.	NERC RoP	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	RoP Section 1700		2/14/11	3/7/11	Yes 3/7/11
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11
14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	Yes 4/8/11
15.	RFC RoP	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments			3/1/11	4/15/11	
16.	NERC RoP	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Appendices 3B and 3D		3/1/11	4/15/11	Yes 4/15/11
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	Yes 4/27/11
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	Yes 5/2/11
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	Yes 5/9/11
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	Yes 5/27/11
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	Yes 5/31/11
22.	Project 2007-03	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	TOP-001 through TOP-008 and PER-001		4/26/11	6/9/11	Yes 6/9/11
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	Yes 6/10/11
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	Yes 6/10/11
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	

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
26.	N/A	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	CAN-0029 PRC-004-1 R1, R2 and R3		5/20/11	6/10/11	
27.	N/A	CAN-0030--Draft CAN-0030 Attestations	CAN-0030 Attestations		5/20/11	6/10/11	
28.	N/A	CAN-0039--Draft CAN-0039 DOE Form 407	CAN-0039 DOE Form 407		5/20/11	6/10/11	
29.	Project 2010-05.1	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)			6/10/11	7/11/11	
30.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-025-2, MOD-027-1, PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		6/15/11	7/15/11	Yes 7/15/11
31.	Project 2010-07	Project 2010-07 – Generator Requirements at the Transmission Interface – Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards		6/17/11	7/17/11	Yes 7/15/11
32.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		6/15/11	8/1/11	Yes 8/1/11
33.	NERC RoP	Proposed Changes to NERC Rules of Procedure and associated Appendices (Appendix 4B – Sanction Guidelines; and Appendix 4C – Compliance Monitoring and Enforcement Program)	Appendices 4B and 4C		6/30/11	8/15/11	
34.	N/A	Compliance Application Notice (CAN) Process	CAN Process		8/15/11	9/6/11	Yes 9/6/11
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	

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
37.	NERC RSDP	NERC 2012-2014 Reliability Standards Development Plan	2012-2014 RSDP		9/12/11	9/26/11	Yes 9/26/11
38.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		8/15/11	9/28/11	Yes 9/28/11
39.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	BES Definition		8/26/11	10/10/11	Yes 10/10/11
40.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Technical Principles for Demonstrating BES Exceptions	Technical Principles for Demonstrating BES Exceptions		8/26/11	10/10/11	Yes 10/10/11
41.	N/A	New CAN Template, five DRAFT CANs for Industry review and CANs Status posted to NERC Compliance's Web site.	CANs		9/23/11	10/14/11	Yes 10/14/11
42.	RoP	Proposed Changes to NERC Rules of Procedure and All Appendices			9/2/11	10/17/11	
43.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Rules of procedure Modifications to Support BES Exception Requests	RoP Section 509, Section 1703 and Appendix 5C		9/13/11	10/27/11	Yes 10/27/11
44.	N/A	CAN-0010--Definition of "Annual" and Implementation of Annual Requirements	CAN-0010 Definition of Annual		10/10/11	10/31/11	Yes 10/31/11
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

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
49.	N/A	CAN-0022--VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode	CAN-0022 VAR-002-1.1b R1 and R3		10/10/11	10/31/11	
50.	N/A	CAN-0024--CIP-002 R3 Routable Protocols and Data Diode Devices	CAN-0024 CIP-002, R3		10/10/11	10/31/11	Yes 10/31/11
51.	N/A	CAN-0026--TOP-006 R3 Protection Relays	CAN-0026 TOP-006, R3		10/10/11	10/31/11	Yes 10/31/11
52.	N/A	CAN-0028--TOP-006-1 R1.2 Reporting Responsibilities	CAN-0028 TOP-006-1, R1.2		10/10/11	10/31/11	
53.	N/A	CAN-0020--TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages	CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002		10/19/11	11/9/11	
54.	N/A	CAN-0030--Attestations	CAN-0030		10/19/11	11/9/11	
55.	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	MOD-028, R3.1		10/3/11	11/16/11	Yes 11/16/11
56.	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Interpretation of COM-002-2, R2		10/4/11	11/18/11	Yes 11/18/11
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

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
64.	N/A	Draft CAN-0027: TOP-003 R2 Coordination of Scheduled Outages	CAN-0027 TOP-003, R2		11/22/11	12/14/11	
65.	NERC RoP	Proposed Changes to the NERC Rules of Procedure and Associated Appendices			11/7/11	12/22/11	
66.	NERC RoP	Notice of Revisions to Proposed New Sections 1.1.24 and 5.11 of Appendix 4C of the NERC Rules of Procedure, as Originally Posted for Comment on November 7, 2011			11/22/11	12/22/11	
67.	Regional Standard	Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		11/22/11	12/22/11	
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	

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
74.	WECC Regional Standard	Regional Reliability Standard BAL-001-0.1a - Real Power Balancing Control Performance - WECC Variance	BAL-001-0.1a		1/23/12	3/9/12	
75.	N/A	NERC Functional Model Demand Response Functions and Entities	NERC Functional Model		2/13/12	3/14/12	
76.	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 for WECC	Interpretation of CIP-004-1		2/8/12	3/23/12	Yes 3/23/12
77.	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Interpretation of CIP-002-1, R3		2/8/12	3/23/12	Yes 3/23/12
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	

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86.	Project 2008-06	Project 2008-06 - Cyber Security Order 706 Version 5 CIP	CIP-002 and CIP-003 - Comment Form A		4/12/12	5/21/12	Yes 5/20/12
			CIP-004 thru CIP-007 - Comment Form B		4/12/12	5/21/12	Yes 5/20/12
			CIP-008 thru CIP-011 - Comment Form C		4/12/12	5/21/12	Yes 5/20/12
			Definitions and Implementation Plan - Comment Form D		4/12/12	5/21/12	Yes 5/20/12
87.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		4/25/12	5/24/12	Yes 5/24/12
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

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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
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

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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
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	

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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	
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

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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
143.	N/A	Rapid Revision Procedure		Informal	2/25/13	3/6/13	Yes 3/6/13
144.	Project 2010-13-2	Project 2010-13-2 - Phase 2 of Relay Loadability - Generation - PRC-025-1	PRC-025-1	Formal	1/25/13	3/11/13	Yes 3/11/13
			Supplemental SAR	Informal	1/25/13	3/11/13	Yes 3/11/13
			Cost Effectiveness	CEAP Pilot	1/25/13	3/11/13	Yes 3/11/13
			RSAW	Feedback	1/25/13	3/11/13	Yes 3/11/13
145.	Project 2012-INT-04	Interpretation 2012-INT-04 - Interpretation of CIP-007 for ITC	Interpretation of CIP-007	Formal	2/6/13	3/22/13	Yes 3/22/13
146.	Project 2012-INT-06	Interpretation 2012-INT-06 - Interpretation of CIP-003 for Consumers Energy	Interpretation of CIP-003	Formal	2/6/13	3/22/13	Yes 3/22/13
147.	Project 2012-08-1	Project 2012-08-1 - Phase 1 of Glossary Updates--Statutory Definitions	Glossary of Terms	Formal	2/21/13	3/22/13	Yes 3/22/13
148.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003-1	COM-003-1	Formal	3/7/13	4/5/13	Yes 4/5/13
			RSAW	Feedback	3/7/13	4/5/13	Yes 4/5/13
149.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-001-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-002-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-013-1	Formal	3/12/13	4/25/13	Yes 4/25/13

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150.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)	Draft SAR	Informal	4/5/13	5/6/13	Yes 5/6/13
			PRC-005-3	Formal	4/5/13	5/6/13	Yes 5/613
151.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation	PRC-023-3 PRC-025-1	Formal	4/25/13	5/24/13	Yes 5/24/13
152.	Project 2007-11	Project 2007-11 - Disturbance Monitoring — PRC-002 and PRC-018	SAR	Informal	5/03/13	6/03/13	Yes 6/3/13
153.	Project 2007-11	Project 2007-11 - Disturbance Monitoring PRC-002 and PRC-018	Request for Information	Informal	6/05/13	7/05/13	
154.	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	PRC-001 and PRC-027		6/04/13	7/03/13	Yes 7/03/13
155.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition		5/29/13	7/12/13	Yes 7/12/13
156.	TRE Regional Standard	Regional Reliability Standard - BAL-001-TRE-01	BAL-001-TRE-01		5/31/13	7/15/13	
157.	N/A	NPCC Regional Standards Process Manual	NPCC RSPM		6/06/13	7/22/13	
158.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003-1		6/20/13	7/19/13	Yes 7/19/13
159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13

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163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13
169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	Yes 9/4/13
170	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System – Phase 2	BES Definition Phase 2	Formal	8/6/13	9/4/13	Yes 9/4/13
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	Yes 9/9/13
172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	Yes 9/13/13
173	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-001-1 FAC-002-1	5-year review	8/1/13	9/16/13	Yes 9/16/13
174	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-003-3 FAC-008-3 FAC-010-2.1 FAC-011-2 FAC-013-2 FAC-014-2	5-year review	8/1/13	9/16/13	Yes 9/16/13
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

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176	Project 2009-03	Project 2009-03 — Five-Year Review of Emergency Operations EOP-001, EOP-002, EOP-003, and IRO-001	EOP-001-2.1b EOP-002-3.1 EOP-003-2	5-year review	8/6/13	9/19/13	Yes 9/19/13
177	Project 2012-09	Project 2012-09 IRO Five-Year Review	IRO-003-2 IRO-004-2 IRO-005-4 IRO-006-5 IRO-006-East IRO-008-1 IRO-009-1 IRO-010-1a	5-year review	8/7/13	9/20/13	Yes 9/20/13
178	Project 2008-02	Project 2008-02 Undervoltage Load Shedding	Revised SAR	Informal	9/10/13	10/9/13	Yes 10/9/13
179	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	9/4/13	10/18/13	Yes 10/18/13
180	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition	Formal	9/27/13	10/28/13	Yes 10/28/13
181	Project 2007-02	Project 2007-02 Operating Personnel Communications Protocols	COM-002-4	Formal	10/21/13	11/7/13	Yes 11/4/13
182	Project 2010-01	Project 2010-01 Training	PER-005-2	Formal	9/27/13	11/12/13	Yes 11/12/13
183	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	Various INT Standards	Formal	9/30/13	11/13/13	Yes 11/13/13
184	Project 2012-05	Project 2012-05 ATC Revisions (MOD A)	MOD-001-2	Formal	10/4/13	11/20/13	Yes 11/18/13
185	Project 2010-03	Project 2010-03 Modeling Data (MOD B)	MOD-032-1, MOD-033-1	Formal	10/07/13	11/20/13	
186	Project 2010-04	Project 2010-04 Demand Data (MOD C)	MOD-031-1	Formal	10/09/13	11/22/13	Yes 11/22/13
187	Project 2013-04	Project 2013-04 Voltage and Reactive Control	VAR-001-4, VAR-002-3	Formal	10/11/13	11/25/13	Yes 11/25/13
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

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191	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-027	Formal	11/04/13	12/18/13	Yes 12/18/13
192	Project 2014-01	Project 2014-01 - Standards Applicability for Dispersed Generation Resources	SAR	Formal	11/20/13	12/19/13	Yes 12/19/13
193	Project 2010-01	Project 2010-01 Training - PER-005-2	PER-005-2	Formal	12/4/13	1/22/14	Yes 1/17/14
194	Project 2010-03	Project 2010-03 Modeling Date - MOD B	MOD-033-1	Formal	12/6/13	1/22/14	Yes 1/21/14
195	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	INT-004-3 INT-010-2	Formal	1/10/14	1/24/14	Yes 1/22/14
196	Project 2007-02	Project 2007-02 Operating Personnel	COM-002-4	Formal	1/22/14	1/31/14	Yes 1/31/14
197	Project 2014-02	Project 2014-02 Standard Authorization Request – Cyber Security Standards	CIP SAR	Informal	1/17/14	2/18/14	Yes 2/18/14
198	2014 Work Plan	2014 Work Plan for NERC Reliability Standards Development	2014 Work plan			2/21/13	Yes 2/21/14
199	Project 2010-17	Project 2010-17 Definition of Bulk Electric System - Phase 2	BES	Informal	1/29/14	2/27/14	Yes 2/27/14
200	Project 2010-05.1	Project 2010-05.1 Protection System: Phase 1 (Misoperations) - PRC-004-3	PRC-004-3	Formal	1/17/14	3/11/14	Yes 3/2/14
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

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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
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

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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 Development Plan		Informal		7/21/14	Yes 7/21/14
226	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Formal	7/16/14	7/25/14	Yes 7/25/14
227	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	06/12/14	7/29/14	Yes 7/29/14
228	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	06/13/14	07/30/14	Yes 7/30/14
229	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Formal	06/23/14	08/8/14	Yes 8/6/14
230	Project 2010-14-2	Project 2010-14-2 Balancing Authority Reliability-based Control Standard Authorization Request for BAL-005 and	BAL-005 BAL-006	Informal	07/16/14	08/14/14	Yes 8/12/14

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		BAL-006					
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
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	Formal	09/03/14	10/17/14	Yes 10/17/14

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
			CIP-010-X CIP-011-X				
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 for Dispersed Generation Resources	PRC-001-1.1 PRC-019-2 PRC-024-1	Formal	11/05/14	12/23/14	Yes 12/22/14
251	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	12/29/14	1/7/15	Yes 1/6/15
252	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-003-7 CIP-004-7 CIP-007-7 CIP-010-3 CIP-011-3 CIP-003-7 CIP-010-3 Implementation Plan	Formal	12/30/14	1/9/15	Yes 1/9/15
253	Project 2014-04	Project 2014-04 Physical Security SAR	SAR	Informal	12/15/14	1/13/15	Yes 1/12/15
254	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	White Paper Appendix A Appendix B	Informal	12/22/14	1/20/15	Yes 1/20/15
255	Project 2014-	Project 2014-01	PRC-005-5	Informal	12/22/14	1/20/15	Yes

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	01	Standards Applicability for Dispersed Generation Resources					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
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	SAR	Informal	4/16/15	5/19/15	Yes 5/19/15

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Directives					
271	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems – RAS	PRC-012-2	Informal	4/30/15	5/20/15	Yes 5/20/15
272	Project 2015-03	Project 2015-03 Periodic Review of System Operating Limit Standards	FAC-010-3 FAC-011-3 FAC-014-2	Formal	5/4/15	6/17/15	Yes 6/17/15
273	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	IRO-006-East-2 IRO-009-2	Formal	5/21/15	7/8/15	Yes 7/8/15
274	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	PRC-005-3	Formal	6/11/15	7/10/15	Yes 7/10/15
275	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generations Resources	PRC-004-2.1 PRC-005-2 PRC-005-3	Informal	6/12/15	7/13/15	Yes 7/13/15
276	Project 2015-07	Project 2015-07 Internal Communications Capabilities	COM-001-2	Informal	6/11/15	7/15/15	Yes 7/15/15
277	Project 2015-04	Alignment of Terms	Glossary Terms	Formal	6/12/15	7/23/15	Yes 7/23/15
278	Project 2009-02	Real-time Monitoring and Analysis Capabilities	SAR	Formal	7/16/15	8/17/15	Yes 8/17/15
279	NERC 2016-2018	Reliability Standards Development Plan	Development Plan	Formal	7/16/15	8/17/15	Yes 8/17/15
280	Project 2015-08	Emergency Operations	EOP-004-2 EOP-005-2 EOP-006-2 EOP-008-1	Informal	7/21/15	8/19/15	Yes 8/19/15
281	Project 2010-14.1	Phase 1 of Balancing Authority Reliability-based Controls	BAL-002-2	Formal	7/7/15	8/20/15	Yes 8/20/15
282	Project 2010-14.2.2	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-	MOD-031 FERC	MOD-031-2	Formal	7/31/15	9/18/15	Yes

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	04.1	Order No. 804 Directives					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 2016-02	Modifications to CIP Standards	SAR	Informal	3/23/16	4/21/16	Yes 4/21/16
303	Project 2007-06.2	Phase 2 of System Protection Coordination	PER-006-1 & Two Definitions	Formal	3/10/16	4/25/16	Yes 4/25/16
304	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	3/23/16	5/9/16	Yes 5/6/16
305	CEP	Cost Effectiveness Pilot	TPL-001-4	Informal	4/27/16	5/26/16	Yes 5/26/16
306	Project 2013-03	Geomagnetic Disturbance Mitigation Revised White Papers	SAR	Informal	5/12/16	6/13/16	Yes 6/13/16
307	Project 2015-10	Single Points of Failure	SAR	Informal	5/26/16	6/24/16	Yes 6/24/16

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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

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

Exhibit A

Order No. 672 Criteria

EXHIBIT A

Order No. 672 Criteria

In Order No. 672, the Commission identified a number of criteria it uses to analyze Reliability Standards that are proposed for approval in order to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest.[1] The discussion below identifies these factors and explains how the proposed retirement of the Regional Reliability Standard meets or exceeds the criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]

This project proposes to retire Regional Reliability Standard PRC-002-NPCC-01 Disturbance Monitoring. The reliability-related objectives are now addressed in a recently-approved NERC Reliability Standard, PRC-002-2 - Disturbance Monitoring and Reporting Requirements.

The project to retire the PRC-002-NPCC-01 Disturbance Monitoring regional standard adhered to the applicable process contained within the FERC-approved *NPCC Regional Standard Processes Manual*. The drafting team, which was composed of subject matter experts, performed a detailed analysis of NERC Reliability Standard PRC-002-2. The purpose of continent-wide Reliability Standard PRC-002-2 is to ensure adequate data is available to facilitate analysis of Bulk Electric System ("BES") Disturbances. Following its review, the drafting team determined that the continent-wide Reliability Standard established adequate

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

[2] Order No. 672 at PP 321, 324.

requirements for data recording capabilities and obviates the need for maintaining the NPCC regional standard. Therefore, it is technically sound to retire the regional standard.

The technical analysis is included in this filing as **Exhibit B** and may also be found on the NPCC website. Biographies of the drafting team members are provided with this filing in **Exhibit C**.

NPCC's process also includes a public iterative comment/response period. No negative comments were received from the industry regarding the proposed retirement.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The PRC-002-NPCC-01 Disturbance Monitoring standard complies with Order No. 672 because it applies only to applicable entities as stated in the standard and it clearly identifies the specific applicable entity assigned to an associated task.

Although this filing does not propose any added regulatory language, the drafting team made every endeavor to ensure the narrative describing its rationale for retirement of the PRC-002-NPCC-01 Disturbance Monitoring Standard was clear, unambiguous, and that the retirement itself would present no reliability-related concerns.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

This project proposes to retire NPCC Regional Reliability Standard PRC-002-NPCC-01 - Disturbance Monitoring. The reliability-related objectives are addressed in FERC-approved

[3] Order No. 672 at PP 322, 325.

[4] Order No. 672 at P 326.

NERC Reliability Standard PRC-002-2 - Disturbance Monitoring and Reporting Requirements. As such, addition or modification of compliance elements is not required.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner. [5]

This project proposes to retire NPCC Regional Reliability Standard PRC-002-NPCC-01 - Disturbance Monitoring. The reliability-related objectives are addressed in FERC-approved NERC Reliability Standard PRC-002-2 - Disturbance Monitoring and Reporting Requirements. As such, addition or modification of measures is not required.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

This project is designed to retire NPCC Regional Reliability Standard PRC-002-NPCC-01 - Disturbance Monitoring because the reliability-related objectives are effectively and efficiently addressed in the continent-wide disturbance monitoring standard. There is no reliability or financial impact as a result of implementing the retirement of the standard.

6. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

This project proposes to retire NPCC Regional Reliability Standard PRC-002-NPCC-01 - Disturbance Monitoring. The reliability-related objectives are addressed in FERC-approved NERC Reliability Standard PRC-002-2 - Disturbance Monitoring and Reporting Requirements. There is no proposed change to the level of reliability or to the practices in place to achieve the

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5 Order No. 672 at P 327.

6 Order No. 672 at P 328.

7 Order No. 672 at PP 329, 330.

existing level of reliability; thus, there is no lessening of the adequacy of the standard for disturbance monitoring and no migration to a lowest common denominator.

During the retirement development history, none of the commenters reported any concerns regarding the financial impact of retiring the PRC-002-NPCC-01 standard.

Furthermore, the implementation plan for Regional Reliability Standard PRC-002-NPCC-01 required full compliance with the standard's requirements on October 2015. The establishment of this regional standard and requirements to install disturbance monitoring equipment has facilitated entity compliance with the future enforceable PRC-002-2 Reliability Standard which specifies disturbance monitoring capability.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]

This project proposes to eliminate a regional standard that is duplicative, with respect to the reliability objective, to the requirements in the FERC-approved continent-wide Reliability Standard PRC-002-2 - Disturbance Monitoring and Reporting Requirements. Retirement of the regional standard and application of the continent-wide Reliability Standard PRC-002-2 will achieve greater continent-wide consistency regarding collection methods for data used in the analysis of BES disturbances.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for

[8] Order No. 672 at P 331.

reliability.[9]

The retirement of NPCC Regional Reliability Standard PRC-002-NPCC-01 - Disturbance Monitoring should cause no undue negative effect on competition or restriction of the grid.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

This project proposes to retire NPCC Regional Reliability Standard PRC-002-NPCC-01 - Disturbance Monitoring and the related NPCC regional definitions of Current Zero Time and Generating Plant to be effective as of July 1, 2016. This proposal would align the retirement of PRC-002-NPCC-01 with the effective date for Reliability Standard PRC-002-2. Entities in the NPCC region have been expected to be fully compliant with PRC-002-NPCC-01 since October 2015. The data requirements in Reliability Standard PRC-002-2 will result in minimal additional data requirements beyond those required to comply with PRC-002-NPCC-01. The proposed retirement of PRC-002-NPCC-01 should be seamless and will not have adverse effects on reliability. Therefore, it is reasonable to align the retirement date of PRC-002-NPCC-01 to the effective date of PRC-002-2.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

In developing its request to retire NPCC Regional Reliability Standard PRC-002-NPCC-01-Disturbance Monitoring, NPCC adhered to the *NPCC Regional Standard Processes Manual* as approved by FERC on December 23, 2014 and posted on the NPCC website.

All meetings were open to the public. Between April 22, 2015 and October 8, 2015, the drafting team conducted three meetings open to the public. Notice of the meetings was provided

9 Order No. 672 at P 332.

10 Order No. 672 at P 333.

11 Order No. 672 at P 334.

to the public via the NPCC website and through email announcements. All meetings were supported by a telephone conference bridge associated with an on-line Internet visual capability, allowing all participants to see the documents as they were being developed.

The project was posted for industry comment. No negative comments were received. The final ballot achieved quorum and sufficient votes for approval. While posted at NERC for a 45-day comment period, commenters were unanimously in accord that the development process was open, inclusive, balanced, transparent, and that due process was followed.

Additional information relating to the development of the proposed retirement is contained in the Petition and in **Exhibit C**.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

Neither NERC nor NPCC is aware of any vital public interests impacted by retirement of this standard. No such balancing concerns were raised or noted.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

This project proposes to retire NPCC Regional Reliability Standard PRC-002-NPCC-01 - Disturbance Monitoring. The reliability-related objectives are addressed in the FERC-approved NERC Reliability Standard PRC-002-2 - Disturbance Monitoring and Reporting Requirements. No additional other factors were relevant with respect to this project.

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12 Order No. 672 at P 335.

13 Order No. 672 at P 323.

Exhibit B

Comparison of PRC-002-NPCC-01 Regional Reliability Standard Requirements to Continent-Wide Reliability Standard PRC-002-2 Requirements

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
LOCATIONS FOR DATA CAPTURE (SER, FR) R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SER) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of Fault recording equipment. This capability shall: 1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island. Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity. 1.2 Monitor the following at each location listed in 1.1: 1.2.1 Transmission and Generator circuit breaker positions 1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1. 1.2.3 Teleprotection keying and receive R2. Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: **2.1** All transmission lines. **2.2** Autotransformers or phase-shifters connected to busses. **2.3** Shunt capacitors, shunt reactors. **2.4** Individual generator line interconnections. **2.5** Dynamic VAR Devices. **2.6** HVDC terminals. **R7.** Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance	**LOCATIONS FOR DATA CAPTURE (SER, FR)** R1. Each Transmission Owner shall: 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1. 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data. 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.	**LOCATIONS FOR DATA CAPTURE (SER, FR)** 3.2. Sequence of Event recorders shall be provided at all **bulk power system** substations and at generating units above 50 MW **capacity**, and at generating plants above 300 MW **capacity** 4.3 **Fault** recording capability shall be provided by the GO for generating units above 200 MW **capacity**. 4.4 **Fault** recorders shall monitor the following **elements** at each location where **fault** recorders are installed: - All **BPS** Transmission Lines - Autotransformers or phase-shifters connected to **BPS** busses - Shunt capacitors 345 kV and above - Individual generator interconnections - Dynamic Var Devices - HVDC Terminals - A Transmission Owner may optionally include the monitoring of transformers serving load from a **BPS** bus. 5.2 On an **Area** basis, there shall be at least ten (10) DDRs per 30,000 MW of peak **load**, distributed throughout the system, and installed at various types of locations, with consideration given to the following factors: - Major **load** centers - Major **generation** clusters - Major voltage sensitive areas - Major transmission interfaces - Major transmission junctions - **Elements** associated with Interconnection Reliability Operating Limits (IROLs) - Major EHV interconnections between control areas. 5.3 An evaluation of the need for a DDR should be made upon each new major **BPS** installation and upon each bulk power system station addition or expansion where a **fault** recorder replacement project is being made. (A field for this purpose will be included in the next revision of Document C-22.) 5.4 DDRs shall monitor the following **elements** at each location where dynamic recorders are installed: - Most lines such that normal maintenance	Because of its Attachment 1 Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data in PRC-002-2, PRC-002-2 does not require SER coverage at as many buses as PRC-002-NPCC-01. There is no FR or SER required by PRC-002-2 from generators. Locations requiring monitoring in PRC-002-NPCC-01 were amended by Compliance Guidance Statements CGS-002 Defining Generator Materiality for Registration dated May 4, 2009 (to be retired 7/1/16), CGS-004 Generating Plant Capacity in PRC-002-NPCC-01 dated March 20, 2013, and CGS-005 Clarification of Monitoring and Enforcement of PRC-002-NPCC-01.	Specifics provided in the sections below on SOE (PRC-002-NPCC-01), SER (PRC-002-2), Fault recording (FR), and DDR.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
Recording (DDR) capability that: **7.1** Provides a minimum of 1 DDR per 3,000 MW of peak Load. **7.2** Records dynamic disturbance information with consideration of the following facilities/locations: **7.2.1** Major Load centers. **7.2.2** Major Generation clusters. **7.2.3** Major voltage sensitive areas. **7.2.4** Major transmission interfaces. **7.2.5** Major transmission junctions. **7.2.6** Elements associated with Interconnection Reliability Operating Limits (IROLs). **7.2.7** Major EHV interconnections between operating areas.		activities do not interfere with DDR requirements. - Bus voltages		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
SOE R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SER) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of Fault recording equipment. This capability shall: 1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island. Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity. 1.2 Monitor the following at each location listed in 1.1: 1.2.1 Transmission and Generator circuit breaker positions 1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1. 1.2.3 Teleprotection keying and receive	**SER** R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses.	**SOE** 3.2. Sequence of Event recorders shall be provided at all **bulk power system** substations and at generating units above 50 MW **capacity**, and at generating plants above 300 MW **capacity** 3.3. Sequence of Events recording shall monitor the following at each location: - Transmission and Generator circuit breaker positions - **Protective Relay** tripping for all **protection groups** - **Teleprotection** keying & receive	PRC-002-NPCC-01 is more specific and inclusive in the locations (substations and generating units) where SOE is to be provided (PRC-002-NPCC-01 Parts 1.1 and 1.2). Also more specific in that it specifies that SER is to be provided for protective relay tripping and teleprotection keying.	3.2--for generating units, 50MW to be changed to 50MVA, 300MW to 300MVA. Add radial loads greater than 300MW, or the operation of which creates a Generation/Load island. Bulk power system to be changed to Bulk Electric System.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
FAULT RECORDING **R2.** Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: **2.1** All transmission lines. **2.2** Autotransformers or phase-shifters connected to busses. **2.3** Shunt capacitors, shunt reactors. **2.4** Individual generator line interconnections. **2.5** Dynamic VAR Devices. **2.6** HVDC terminals. **R3.** Each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements. **R4.** Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (GSU) transformer to a Bulk Electric System Element unless Fault recording capability is already provided by the Transmission Owner. **R5.** Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following: **5.1** Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.) **5.2** Three phase currents and neutral currents. **5.3** Polarizing currents and voltages, if used. **5.4** Frequency. **5.5** Real and reactive power. **R6.** Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities: **6.1** Each Fault recorder record duration shall be a minimum of one (1) second. **6.2** Each Fault recorder shall have a minimum recording rate of 16 samples per cycle	**FAULT RECORDING** R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: 3.1 Phase-to-neutral voltage for each phase of each specified BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1 Transformers that have a low-side operating voltage of 100kV or above. 3.2.2 Transmission Lines. R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: 4.1 A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or • At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder. 4.2 A minimum recording rate of 16 samples per cycle. 4.3 Trigger settings for at least the following: 4.3.1 Neutral (residual) overcurrent. 4.3.2 Phase undervoltage or overcurrent.	**FAULT RECORDING** 4.1 **Fault** recording is the responsibility of transmission owners and **generation** owners. When adding or replacing a DFR at an existing BPS facility, the TO or GO should complete a notification in accordance with Document C-22. 4.2 **Fault** recording shall be provided by the TO to determine the current zero time for loss of **BPS** transmission **elements**. The current zero time shall be reported as the time of the final current zero on the last phase to interrupt. 4.3 **Fault** recording capability shall be provided by the GO for generating units above 200 MW **capacity**. 4.4 **Fault** recorders shall monitor the following **elements** at each location where **fault** recorders are installed: - All **BPS** Transmission Lines - Autotransformers or phase-shifters connected to **BPS** busses - Shunt capacitors 345 kV and above - Individual generator interconnections - Dynamic Var Devices - HVDC Terminals - A Transmission Owner may optionally include the monitoring of transformers serving load from a **BPS** bus. 4.5 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following: - Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.) - Three phase currents and neutral currents. - Polarizing currents and voltages, if used. - Frequency. - Active and reactive power. 4.6 **Fault** recorder record duration shall be a minimum of one (1) second. 4.7 **Fault** recorder minimum recording rate shall be 16 samples per cycle. 4.8 As a minimum, **fault** recorders shall be set to trigger for all the following functions:	Because of its Attachment 1 Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data, PRC-002-2 doesn't require SER coverage at as many buses as PRC-002-NPCC-01. Current Zero Time is not addressed in PRC-002-2. There NO FR required by PRC-002-2 from generators. PRC-002-2 does not require recording polarizing currents or voltages, frequency, and real and reactive power. PRC-002-NPCC-01 specifies a record duration of one (1) second. PRC-002-2 specifies "at least 30-cycles" or "two cycles of the pre-trigger data…and the final cycle of the fault…" PRC-002-NPCC-01 specifies fault recorder triggering for specified per unit values of rated CT secondary current, set per unit values of neutral (residual) overcurrent, specified undervoltage per unit value, and documentation of additional triggers when necessary.	Triggering for monitored phase overcurrent set at 1.5 pu or less. 4.4--Change BPS to BES Remove "345kV and above" from shunt capacitors Add shunt reactors 4.1--Change BPS to BES 4.2-- Change BPS to BES 4.3--Change MW to MVA 4.5--Change Active to Real 4.8--Add monitored phase overcurrent set at 1.5 pu or less of rated CT secondary current Add "or greater" to "Phase undervoltage set at 0.85 pu"

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
6.3 Each Fault recorder shall be set to trigger for at least the following: **6.3.1** Monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups. **6.3.2** Neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current. **6.3.3** Monitored phase undervoltage set at 0.85 pu or greater. **6.4** Document additional triggers and deviations from the settings in 6.3.2 and 6.3.3 when local conditions dictate.		- **Protective Relay** tripping for all **protection groups** - Neutral (residual) overcurrent set at 0.2 pu rated CT secondary current - Phase undervoltage set at 0.85 pu 4.9 When local conditions require different settings or additional functions, such situations shall be documented.		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
DYNAMIC DISTURBANCE RECORDING **R7.** Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: **7.1** Provides a minimum of 1 DDR per 3,000 MW of peak Load. **7.2** Records dynamic disturbance information with consideration of the following facilities/locations: **7.2.1** Major Load centers. **7.2.2** Major Generation clusters. **7.2.3** Major voltage sensitive areas. **7.2.4** Major transmission interfaces. **7.2.5** Major transmission junctions. **7.2.6** Elements associated with Interconnection Reliability Operating Limits (IROLs). **7.2.7** Major EHV interconnections between operating areas. **R8.** Each Reliability Coordinator shall specify that DDRs installed, after the approval of this standard, function as continuous recorders. **R9.** Each Reliability Coordinator shall specify that DDRs are installed with the following capabilities: **9.1** A minimum recording time of sixty (60) seconds per trigger event. **9.2** A minimum data sample rate of 960 samples per second, and a minimum data storage rate for RMS quantities of six (6) data points per second. **9.3** Each DDR shall be set to trigger for at least one of the following (based on manufacturers' equipment capabilities): **9.3.1** Rate of change of Frequency. **9.3.2** Rate of change of Power. **9.3.3** Delta Frequency (recommend 20 mHz change). **9.3.4** Oscillation of Frequency. **R10.** Each Reliability Coordinator shall establish requirements such that the following quantities are monitored or derived where DDRs are installed: **10.1** Line currents for most lines such that	**DYNAMIC DISTURBANCE RECORDING** R5. Each Responsible Entity shall: 5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: 5.1.1 Generating resource(s) with: 5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA. 5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA. 5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). 5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. 5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL). 5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. 5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: 5.2.1 One BES Element; and 5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. 5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. 5.4 Re-evaluate all BES Elements at least once	**DYNAMIC DISTURBANCE RECORDING** 5.1 Where the DDR capability is deemed necessary by the Reliability Coordinator, the Reliability Coordinator shall provide guidance in setting triggers and shall monitor the performance of the DDR devices. 5.2 On an **Area** basis, there shall be at least ten (10) DDRs per 30,000 MW of peak **load**, distributed throughout the system, and installed at various types of locations, with consideration given to the following factors: - Major **load** centers - Major **generation** clusters - Major voltage sensitive areas - Major transmission interfaces - Major transmission junctions - **Elements** associated with Interconnection Reliability Operating Limits (IROLs) - Major EHV interconnections between control areas. 5.3 An evaluation of the need for a DDR should be made upon each new major **BPS** installation and upon each bulk power system station addition or expansion where a **fault** recorder replacement project is being made. (A field for this purpose will be included in the next revision of Document C-22.) 5.4 DDRs shall monitor the following **elements** at each location where dynamic recorders are installed: - Most lines such that normal maintenance activities do not interfere with DDR requirements. - Bus voltages 5.5 As a minimum, DDRs shall monitor one phase current per monitored **element** and two phase-to-neutral voltages of different **elements**. One of the monitored voltages shall be of the same phase as the monitored current. 5.6 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following: - Voltage, current, and frequency - Active and reactive power 5.7 DDRs installed after January 1, 2009 shall function	For non-continuous recorders, PRC-002-2 specifies triggered record lengths of at least 3 minutes versus 60 seconds for PRC-002-NPCC-01 (R9). PRC-002-2 specifies an output recording rate of at least 30 times per second. PRC-002-NPCC-01 specifies a minimum data storage rate of 6 data points per second. PRC-002-2 specifies an off nominal frequency trigger (if used). PRC-002-2 is specific on the rate of change of frequency trigger values (if used). PRC-002-2 specifies an undervoltage trigger (if used). PRC-002-NPCC-01 specifies a rate of change of Power trigger (if used). PRC-002-NPCC-01 specifies a Delta Frequency trigger (if used), and an oscillation of Frequency trigger (if used). PRC-002-2 stipulates that normal line maintenance does not interfere with DDR functionality for monitoring line currents. PRC-002-2 stipulates that normal bus maintenance does not interfere with DDR functionality for monitoring bus voltages. PRC-002-NPCC-01 addresses DDR installation. PRC-002-2 does not address equipment.	5.1--Add "The Reliability Coordinator shall request DDR capability, and shall, with Transmission Owners, and Generator Owners mutually agree on an implementation schedule." 5.2--Change "control" to "operating". 5.3--Change BPS to BES Change "bulk power System" to Bulk Electric System 5.4--Revise first bullet to read "Lines and buses such that …" 5.4--"Bus voltages" should be "bus". 5.6--Change Active to real. Add 5.12: Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings and the required list of monitored quantities and report this to NPCC upon request.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
normal line maintenance activities do not interfere with DDR functionality. **10.2** Bus voltages such that normal bus maintenance activities do not interfere with DDR functionality. **10.3** As a minimum, one phase current per monitored Element and two phase-to-neutral voltages of different Elements. One of the monitored voltages shall be of the same phase as the monitored current. **10.4** Frequency. **10.5** Real and reactive power. **R11.** Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and report this to the Regional Entity (RE) upon request. **R12.** Each Reliability Coordinator shall specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners. **R13.** Each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR shall acquire and install the DDR in accordance with R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule.	every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan. R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 6.1 One phase-to-neutral or positive sequence voltage. 6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. 6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. 6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: 7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level. 7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current. 7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. 7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1. R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective	as continuous recorders. 5.8 Each device shall sample data at a rate of at least 960 samples per second (16 samples per cycle and shall store the RMS value of electrical quantities at a rate of at least 6 data points per second.) 5.9 The following DDR triggers shall be considered where available based on manufacturers capability: - Rate of change of Frequency - Rate of change of Power - Delta Frequency 20 mHz change - Oscillation of Frequency 5.10 When local conditions require different settings or additional functions, such situations shall be documented. 5.11 When DDR triggers are used, duration of triggered records shall be a minimum of sixty (60) seconds.		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
	date of this standard and is not capable of continuous recording, triggered records must meet the following: 8.1 Triggered record lengths of at least three minutes. 8.2 At least one of the following three triggers: • Off nominal frequency trigger set at: Low High o Eastern Interconnection <59.75Hz >61.0Hz o Western Interconnection <59.55Hz >61.0Hz o ERCOT Interconnection <59.35Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55Hz >61.5Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec >0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec >0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec >0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec >0.1875 Hz/sec • Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds. R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.			

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
TIME SYNCHRONIZATION **R14.** Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: **14.1** Maintenance and testing intervals and their basis. **14.2** Summary of maintenance and testing procedures. **14.3** Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)). **14.4** Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **14.5** Monthly verification of active analog quantities. **14.6** Verification of DDR and DFR settings in the software every six (6) years. **14.7** A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.	**TIME SYNCHRONIZATION** R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: 10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset. 10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.	**TIME SYNCHRONIZATION** **7.0 Time Synchronization** Internal clocks in DME devices shall be time synchronized to within 2 milliseconds or less of Coordinated Universal Time (UTC) scale. The time zone shall be clearly identified as either universal time zone or local time zone. **PRC-018-1 Requirement** R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements: R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar days.	PRC-002-2, and PRC-018-1 (to be retired 6 years after the implementation date for PRC-002-2) specify synchronization of ± 2 milliseconds and its coordination to UTC.	Section 6--Add 7.1: Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **NOTE: This is also in B-26 Guide for Application of Disturbance Recording Equipment**

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
DATA SPECIFICATIONS **R15.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases: **15.1** NERC, Regional Entity, Reliability Coordinator. **15.2** Request from other Transmission Owners, Generator Owners within NPCC. **R16.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements: **16.1** The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111. **16.2** Disturbance Data files shall be named in conformance with the latest revision of IEEE Standard C37.232. **16.3** Fault Recorder and DDR Files shall contain all monitored channels. SER records shall contain station name, date, time resolved to milliseconds, SER point name, status.	**DATA SPECIFICATIONS** **R11.** Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: **11.1** Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded. **11.2** Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor. **11.3** SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2. **11.4** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later. **11.5** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.	**DATA SPECIFICATIONS** 6.1 Recorded **disturbance** data from DMEs shall be forwarded within 30 days of receipt of the request in each of the following cases: - Request from NERC **Disturbance** Investigation Team - Request from NPCC **Disturbance** Investigation Team - Reliability Coordinator Request 6.2 Data forwarded shall be archived in its native format for a period of 3 years by the TO or GO. 6.3 **Disturbance** data files shall be provided in a format which is capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool (8). 6.4 Disturbance Data files shall be named in conformance with IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 6.5 **Fault** Recorder and DDR Files shall contain all monitored channels. SER records shall contain station, date, time resolved to milliseconds, SER point name, status. 6.6 Recorded data from each **disturbance** shall be retrievable for 10 calendar days. This requirement does not apply to **relays** unless those **relays** are designated as DME. **PRC-018-1 Requirement** R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements: R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar	PRC-002-2 stipulates 30 days unless an extension is granted. PRC-002-2 and PRC-018-1 stipulate that data is retrievable for 10 calendar days. PRC-002-2 is more specific on the data parameters. PRC-002-NPCC-01 is more specific as to the time resolution for SER data. PRC-018-1 stipulates archiving of data for at least three years. A-15 specifies archiving for 3 years. Note: PRC-018-1 is going to be retired in six years after the implementation period for PRC-002-2.	Section 6-- **NOTE: This is also in C-25 Procedure to Collect Power System Event Data for Analysis of System Performance**

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
		days. R4. The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4). R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
STATUS OF RECORDING CAPABILITY **R14.** Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: **14.1** Maintenance and testing intervals and their Basis. **14.2** Summary of maintenance and testing procedures. **14.3** Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)). **14.4** Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **14.5** Monthly verification of active analog quantities. **14.6** Verification of DDR and DFR settings in the software every six (6) years. **14.7** A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.	**STATUS OF RECORDING CAPABILITY** **R12.** Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: • Restore the recording capability, or • Submit a Corrective Action Plan (CAP) Regional Entity and implement it.	**STATUS OF RECORDING CAPABILITY** **8.0 Maintenance And Testing** Each TO, and GO shall establish a maintenance and testing program for DME (guidance for maintenance and testing is provided in Document B-26) that includes: • Maintenance and testing intervals and their basis. • Summary of maintenance and testing procedures. **PRC-018-1 Requirement** R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes: R6.1. Maintenance and testing intervals and their basis. R6.2. Summary of maintenance and testing procedures.		With the exception of PRC-002-NPCC-01 Part 14.4 (time synchronization), Requirement R14 to be added. **NOTE: This is also in B-26 Guide for Application of Disturbance Recording Equipment**

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
DATA ON THE DISTURBANCE MONITORING EQUIPMENT **R17.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall maintain, record and provide to the Regional Entity (RE), upon request, the following data on the DMEs installed to meet this standard: **17.1** Type of DME. **17.2** Make and model of equipment. **17.3** Installation location. **17.4** Operational Status. **17.5** Date last tested. **17.6** Monitored Elements. **17.7** All identified channels. **17.8** Monitored electrical quantities.	**DATA ON THE DISTURBANCE MONITORING EQUIPMENT** Not Applicable.	**DATA ON THE DISTURBANCE MONITORING EQUIPMENT** 6.7 The TO and GO shall each maintain and be ready to report to NPCC on request the following data on the DMEs installed to meet this standard: - Type of DME - Make and model of equipment - Installation location - Operational Status - Date last tested - Monitored **Elements** - Monitored Devices - Monitored Electrical Quantities **PRC-018-1 Requirement** R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1): R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder). R3.2. Make and model of equipment. R3.3. Installation location. R3.4. Operational status. R3.5. Date last tested. R3.6. Monitored elements, such as transmission circuit, bus section, etc. R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc. R3.8. Monitored electrical quantities, such as voltage, current, etc.	No gaps with PRC-018-1.	6.7--Revise "Monitored Devices" bullet to read "All identified channels"

Exhibit C

Complete Record of Retirement Development

Regional Reliability Standards Under Development

Regional Reliability Standards - Under Development				
Standard No.	**Title**	**Regional Status**	**Dates**	**NERC Status**
Northeast Power Coordinating Council (NPCC)				
PRC-002-NPCC-01	Disturbance Monitoring	Standard Under Development	01/06/16 - 02/19/16	Proposed Standard for Retirement **(1)** Ballot Results Announcement **(2)** Info **(3)** Submit Comments Unofficial Comment Form (Word) **(4)**

A. Introduction

1. **Title:** **Disturbance Monitoring**

2. **Number:** PRC-002-NPCC-01

3. **Purpose:** Ensure that adequate disturbance data is available to facilitate Bulk Electric System event analyses. All references to equipment and facilities herein unless otherwise noted will be to Bulk Electric System (BES) elements.

4. **Applicability:**

   4.1. Transmission Owner

   4.2. Generator Owner

   4.3. Reliability Coordinator

5. **(Proposed) Effective Date:** To be established.

B. Requirements

R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SOE) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of Fault recording equipment. This capability shall: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island.

Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity.

1.2 Monitor the following at each location listed in 1.1:

1.2.1 Transmission and Generator circuit breaker positions

1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1.

1.2.3 Teleprotection keying and receive

R2. Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

2.1 All transmission lines.

2.2 Autotransformers or phase-shifters connected to busses.

2.3 Shunt capacitors, shunt reactors.

2.4 Individual generator line interconnections.

2.5 Dynamic VAR Devices.

2.6 HVDC terminals.

R3. Each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R4. Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (GSU) transformer to a Bulk Electric System Element unless Fault recording capability is already provided by the Transmission Owner. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R5. Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

5.1 Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.)

5.2 Three phase currents and neutral currents.

5.3 Polarizing currents and voltages, if used.

5.4 Frequency.

5.5 Real and reactive power.

R6. Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

6.1 Each Fault recorder record duration shall be a minimum of one (1) second.

6.2 Each Fault recorder shall have a minimum recording rate of 16 samples per cycle

6.3 Each Fault recorder shall be set to trigger for at least the following:

6.3.1 Monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups.

6.3.2 Neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current.

6.3.3 Monitored phase undervoltage set at 0.85 pu or greater.

6.4 Document additional triggers and deviations from the settings in 6.3.2 and 6.3.3 when local conditions dictate.

R7. Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

7.1 Provides a minimum of 1 DDR per 3,000 MW of peak Load.

7.2 Records dynamic disturbance information with consideration of the following facilities/locations:

7.2.1 Major Load centers.

7.2.2 Major Generation clusters.

7.2.3 Major voltage sensitive areas.

7.2.4 Major transmission interfaces.

7.2.5 Major transmission junctions.

7.2.6 Elements associated with Interconnection Reliability Operating Limits (IROLs).

7.2.7 Major EHV interconnections between operating areas.

R8. Each Reliability Coordinator shall specify that DDRs installed, after the approval of this standard, function as continuous recorders. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R9. Each Reliability Coordinator shall specify that DDRs are installed with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

9.1 A minimum recording time of sixty (60) seconds per trigger event.

9.2 A minimum data sample rate of 960 samples per second, and a minimum data storage rate for RMS quantities of six (6) data points per second.

9.3 Each DDR shall be set to trigger for at least one of the following (based on manufacturers' equipment capabilities):

9.3.1 Rate of change of Frequency.

9.3.2 Rate of change of Power.

9.3.3 Delta Frequency (recommend 20 mHz change).

9.3.4 Oscillation of Frequency.

R10. Each Reliability Coordinator shall establish requirements such that the following quantities are monitored or derived where DDRs are installed: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

10.1 Line currents for most lines such that normal line maintenance activities do not interfere with DDR functionality.

10.2 Bus voltages such that normal bus maintenance activities do not interfere with DDR functionality.

10.3 As a minimum, one phase current per monitored Element and two phase-to-neutral voltages of different Elements. One of the monitored voltages shall be of the same phase as the monitored current.

10.4 Frequency.

10.5 Real and reactive power.

R11. Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and

report this to the Regional Entity (RE) upon request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R12. Each Reliability Coordinator shall specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R13. Each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR shall acquire and install the DDR in accordance with R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R14. Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

14.1 Maintenance and testing intervals and their basis.

14.2 Summary of maintenance and testing procedures.

14.3 Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)).

14.4 Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center).

14.5 Monthly verification of active analog quantities.

14.6 Verification of DDR and DFR settings in the software every six (6) years.

14.7 A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.

R15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

15.1 NERC, Regional Entity, Reliability Coordinator.

15.2 Request from other Transmission Owners, Generator Owners within NPCC.

R16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

16.1 The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111.

16.2 Disturbance Data files shall be named in conformance with the latest revision of IEEE Standard C37.232.

16.3 Fault Recorder and DDR Files shall contain all monitored channels. SOE records shall contain station name, date, time resolved to milliseconds, SOE point name, status.

R17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall maintain, record and provide to the Regional Entity (RE), upon request, the following data on the DMEs installed to meet this standard: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

17.1 Type of DME.

17.2 Make and model of equipment.

17.3 Installation location.

17.4 Operational Status.

17.5 Date last tested.

17.6 Monitored Elements.

17.7 All identified channels.

17.8 Monitored electrical quantities.

C. Measures

M1. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Sequence of Event recording capability in accordance with 1.1 and 1.2. (R1)

M2. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 2.1 to 2.6. (R2)

M3. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability that determined the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements in accordance with R3.

M4. Each Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability for its Generating Plants at and above 200 MVA Capacity in accordance with R4.

M5. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it records for Faults, sufficient electrical quantities for each monitored Element to determine the parameters listed in 5.1 to 5.5. (R5)

M6. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 6.1 to 6.4. (R6)

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it established its area's requirements for Dynamic Disturbance Recording (DDR) capability in accordance with 7.1 and .2. (R7)

M8. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs installed after the approval of this standard function as continuous recorders. (R8)

M9. Each Reliability Coordinator shall have, and provide upon request, evidence that it developed DDR setting triggers to include the parameters listed in 9.1 to 9.3. (R9)

M10. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs monitor the Elements listed in 10.1 through 10.5. (R10)

M11. Each Reliability Coordinator shall have, and provide upon request, evidence that it documented additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10. (R11)

M12. Each Reliability Coordinator shall have, and provide upon request, evidence that it specified its DDR requirements which included the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners in the Reliability Coordinator's area. (R12)

M13. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it acquired and installed the DDRs in accordance with the specifications contained in the Reliability Coordinator's request, and a mutually agreed upon implementation schedule. (R13)

M14. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it has a maintenance and testing program for stand alone DME

(equipment whose only purpose is disturbance monitoring) that meets the requirements in 14.1 through 14.7. (R14)

M15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided recorded disturbance data from DMEs within 30 days of the receipt of the request from the entities listed in 15.1 and 15.2. (R15)

M16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it submitted the data files in a format that meets the requirements in 16.1 through 16.3. (R16)

M17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it maintained a record of and provided to NPCC when requested, the data on DMEs installed meeting the requirements 17.1 through 17.8. (R17)

D. 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 Transmission Owner and Generator Owner shall keep evidences for three calendar years for Measures 1, 5, 6, 13, 16 and 17.

The Transmission Owner shall keep evidence for three years for Measures 2 and 3.

The Generator Owner shall keep evidence for three years for Measure 4.

The Reliability Coordinator shall keep evidence for three years for Measures 7, 8, 9, 10, 11, 12, 16 and 17.

The Transmission Owner and Generator Owner shall keep evidences for twenty-four calendar months for Measures 14 and 15.

The Reliability Coordinator shall keep evidence for twenty-four calendar months for Measure 15.

If a Transmission Owner, Generator Owner or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit and all subsequent record.

1.4. Compliance Monitoring and Assessment Processes

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting
- Compliance Violation Investigations
- Complaints

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1 The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed…	Up to and including 10% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 10% and up to and including 20% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 20% and up to and including 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.
R2 The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed…	Up to and including 10% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 10% and up to and including 20% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 20% and up to and including 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.
R3 The Transmission	Not applicable.	Not applicable.	Not applicable.	Fault recording capability that determines the

Owner failed to provide…				current zero time for loss of transmission Elements.
R4 The Generator Owner failed to provide Fault recording capability at…	Up to and including 10% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 10% and up to and including 20% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 20% and up to 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.
R5 The Transmission Owner or Generator Owner failed to record for the Faults…	Up to and including 10% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 10% and up to and including 20% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 20% and up to and including 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.
R6 The Transmission Owner or Generator Owner failed …	To provide Fault recording capability for up to and including 10% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1	To provide Fault recording capability for more than 10% and up to and including 20% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or	To provide Fault recording capability for more than 20% and up to and including 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in	To provide Fault recording capability for more than 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than ten (10) locations.

	through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for up to 2 locations.	deviations from the settings stipulated in 6.3 through 6.4 for more than two (2) and up to and including five (5) locations.	6.3 through 6.4 for more than five (5) and up to and including ten (10) locations.	
R7 The Reliability Coordinator failed to establish its area's requirements for…	Up to and including 10% of the required DDR coverage for its area as per 7.1and 7.2.	More than 10% and up to and including 20% of the required DDR coverage for its area as per 7.1 and 7.2.	More than 20% and up to and including 30% of the required DDR coverage for its area as per 7.1 and 7.2.	More than 30% of the required DDR coverage for its area as per 7.1 and 7.2.
R8 The Reliability Coordinator failed to specify that DDRs installed…	Not applicable.	Not applicable.	Not applicable.	Function as continuous recorders.
R9 The Reliability Coordinator failed to specify that DDRs are installed without…	Not applicable.	Not applicable.	Not applicable.	The capabilities listed in 9.1 through 9.3.
R10 The Reliability Coordinator failed to ensure that the quantities listed in are monitored or derived…	Not applicable. 10.1 through 10.5	Not applicable.	Not applicable.	Where DDRs are installed.
R11 The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings from the required trigger settings described in R9	Up to two (2) facilities within the Reliability Coordinator's area that have a DDR. and deviations	More than two (2) and up to five (5) facilities within the Reliability Coordinator's area that have a DDR.	More than five (5) and up to ten (10) facilities within the Reliability Coordinator's area that have a DDR.	More than ten (10) facilities within the Reliability Coordinator's area that have a DDR.

and the required list of monitored quantities as described in R10 for…				
R12 The Reliability Coordinator failed to specify to the Transmission Owners and Generator Owners its DDR requirements including the DDR setting triggers established in R9 but missed…	Not applicable.	Not applicable.	Not applicable.	Established setting triggers.
R13 The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for…	Up to and including 10% of the requirement set of the Reliability Coordinator's request to install DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 10% and up to 20% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 20% and up to 30% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 30% of the requirement set requested by the Reliability Coordinator and installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR OR The Reliability Coordinator, Transmission Owners, and Generator Owners failed to mutually agree on an implementation schedule.
R14 The Transmission Owner or Generator Owner…	Established a maintenance and testing program for stand alone DME but provided incomplete data for any one (1) of 14.1 through	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than one (1) and up to and including three (3) of 14.1 through 14.7.	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than three (3) and up to and including six (6) of 14.1 through 14.7.	Did not establish any maintenance and testing program for DME; OR The Transmission Owner or Generator Owner established a maintenance and testing program for DME but did not provide any data that

	14.7.			meets all of 14.1 through 14.7.
R15 The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for…	Up to and including fifteen (15) days in meeting the requests of an entity, or entities in 15.1, or 15.2.	More than fifteen (15) days but less than and including thirty (30) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than 30 days but less than and including forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.
R16 The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit…	Up to and including two (2) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than two (2) and up to and including five (5) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than five (5) and up to and including ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.
R17 The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity , upon request…	Up to and including two (2) of the items in 17.1 through 17.8.	More than two (2) and up to and including four (4) of the items in 17.1 to 17.8.	More than four (4) and up to and including six (6) of the items in 17.1 through 17.8.	More than six (6) of the items in 17.1 through 17.8.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	November 4, 2010	Adopted by NERC Board of Trustees	New
1	October 20, 2011	FERC Order issued approving PRC-002-NPCC-01 (FERC's Order became effective on October 20, 2011)	

NPCC, Inc.

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

December 2nd, 2015

NPCC Full and General Members:

In accordance with the NPCC Regional Standard Processes Manual the ballot period for the retirement of NPCC Regional Standard PRC-002-NPCC-02 Disturbance Monitoring closed at 23:59PM on November 26th, 2015.

The results of the ballot were as follows:

Quorum: 69.69% of the Total Registered.
Approval: 97.10%

No negative ballots were received with comments therefore, in accordance with our Standards Processes Manual a recommendation for final Regional approval will be sent to the NPCC Board of Directors for consideration at their meeting on February 2, 2016.

Contingent upon the approval of the NPCC BOD, the proposal to retire PRC-002-NPCC-02 will be submitted to the NERC Board of Trustees with subsequent filings with the FERC and applicable provincial authorities.

Voting was conducted electronically and the full retirement record for the standard may be viewed at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=120

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Reliability Standards Announcement

Proposed Retirement of PRC-002-NPCC-01

Comment Period Open through February 19, 2016

Now Available

The Northeast Power Coordinating Council (NPCC) has requested NERC to post regional reliability standard **PRC-002-NPCC-01 – Disturbance Monitoring** for a 45-day industry review as permitted by the NERC Rules of Procedure. The comment period is open through **8 p.m. Eastern, Friday, February 19, 2016.**

Commenting

Use the electronic form to submit comments. If you experience any difficulties in using the electronic form, contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the Regional Reliability Standards Under Development Page.

Background

During 2014 and 2015, NERC completed, filed, and gained the FERC approval of the NERC PRC-002-2 Disturbance Monitoring (DM) continent-wide standard. In conformance with the ERO's strategic direction with respect to regional standards, NPCC conducted a review of the DM regional and continent-wide standards. It was determined that the NPCC regional standard was no longer necessary and initiated the process to retire it.

Regional Reliability Standards Development Process

Section 300 of NERC's Rules of Procedures of the Electric Reliability Organization governs the regional reliability standards development process.

For more information or assistance, contact Reliability Standards Analyst, Mat Bunch (via email) or at 404-446-9785.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Recommended Retirement of Regional Reliability Standard PRC-002-NPCC-01

DO NOT use this form for submitting comments. Use the electronic form to submit comments on the proposed retirement of Regional Reliability Standard **PRC-002-NPCC-01 – Disturbance Monitoring**. The electronic form must be submitted by **8 p.m. Eastern, Friday, February 19, 2016.**

Documents and information about this project are available on the Regional Reliability Standards Under Development page. If you have questions, contact Mat Bunch (via email) or at 404-446-9785.

Background Information

During 2014 and 2015, NERC completed, filed, and gained the FERC approval of the NERC PRC-002-2 Disturbance Monitoring continent-wide standard. In conformance with the ERO's strategic direction with respect to regional standards, NPCC conducted a review of the DM regional and continent-wide standards. It was determined that the NPCC regional standard was no longer necessary and initiated the process to retire it.

The approval process for the retirement of a regional reliability standard requires NERC to publicly notice and request comment on the proposed standard. Comments shall be permitted only on the following criteria (technical aspects of the standard are vetted through the regional standards development process):

Open — Regional reliability standards shall provide that any person or entity that is directly and materially affected by the reliability of the bulk power system 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.

Inclusive — Regional reliability standards 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.

Balanced — Regional reliability standards shall have a balance of interests and shall not be dominated by any two-interest categories and no single-interest category shall be able to defeat a matter.

Due Process — Regional reliability standards shall provide for reasonable notice and opportunity for public comment. At a minimum, the standard shall include public notice of the intent to develop a standard, a public comment period on the proposed standard, due consideration of those public comments, and a ballot of interested stakeholders.

Transparent — All actions material to the process of retiring regional reliability standards shall be transparent. All standards development meetings shall be open and publicly noticed on the regional entity's Web site.

Review the proposed retirement of PRC-002-NPCC-01 regional standard and answer the following questions:

1. Do you agree the process of retiring PRC-002-NPCC-01 met the "Open" criteria as outlined above? If "No", please explain in the comment area below.

☐ Yes
☐ No
Comments:

2. Do you agree the process of retiring PRC-002-NPCC-01 met the "Inclusive" criteria as outlined above? If "No", please explain in the comment area below.

☐ Yes
☐ No
Comments:

3. Do you agree the process of retiring PRC-002-NPCC-01 met the "Balanced" criteria as outlined above? If "No", please explain in the comment area below.

☐ Yes
☐ No
Comments:

4. Do you agree the process of retiring PRC-002-NPCC-01 met the "Due Process" criteria as outlined above? If "No", please explain in the comment area below.

☐ Yes
☐ No
Comments:

5. Do you agree the process of retiring PRC-002-NPCC-01 met the "Transparent" criteria as outlined above? If "No", please explain in the comment area below.

☐ Yes
☐ No
Comments:

NORTHEAST POWER COORDINATING COUNCIL, INC.
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March 25, 2015

Subject: Solicitation for NPCC Regional Standard Drafting Team Members for "Disturbance Monitoring" PRC-002-NPCC-02

Dear Sir/Madam,

A new RSAR for NPCC Regional Standard PRC-002-NPCC-02 Disturbance Monitoring has been approved by the RSC, and assigned to TFSP by the RCC. In accordance with the NPCC Regional Standard Processes Manual , NPCC is soliciting for any interested candidates to assist with the drafting of the standard. The anticipated workload is 2-3 "in-person" meetings and 4-6 teleconferences. Attached is a self-nomination form to be completed and returned by any interested persons no later than April 10th, 2015. The Regional Standards Committee will review and approve any additional qualified candidates who self nominate at its April 22-23, 2015 meeting. Please distribute this email to any potential interested candidates. This information will also be posted on the NPCC website.

Sincerely,

Lee Pedowicz
Manager of Reliability Standards
NPCC Inc.
1040 Avenue of the Americas, 10th Floor
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lpedowicz@npcc.org

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Nomination Form for "PRC-002-NPCC-02", Disturbance Monitoring, Standard Drafting Team

Please return this form to NPCCstandard@npcc.org by **April 10, 2015** with the name of the RSAR or Standard Drafting Team in the subject line. If you have any questions, please contact Lee Pedowicz at lpedowicz@npcc.org , or by telephone at 212-840-1040.
All candidates' qualifications will be reviewed and participation on a drafting team is subject to the approval by the NPCC Regional Standards Committee, RSC. Applicants are expected to be prepared to participate actively at the Drafting Team meetings.

Name: Organization: Address: Office Telephone: E-mail:
Please briefly describe your experience and qualifications to serve on the PRC-002-NPCC-02 Drafting Team.

I represent the following NERC Reliability Region(s) (check all that apply):	**I represent the following NPCC Bylaw Defined Industry Sectors (check one):**	
☐ ERCOT ☐ FRCC ☐ MRO ☐ NPCC ☐ RFC ☐ SERC ☐ SPP ☐ WECC ☐ NA – Not Applicable	☐	1 — Transmission Owners
	☐	2 — Reliability Coordinators
	☐	3 — TDUs, Distribution Companies and Load-Serving Entities
	☐	4 — Generator Owners
	☐	5 — Marketers, Brokers and Aggregators
	☐	6 — State and Provincial Regulatory and/or Governmental Authorities
	☐	7 — Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities

Which of the following Function(s)[1] do you have expertise or responsibilities:

☐ Balancing Authority	☐ Planning Coordinator
☐ Compliance Enforcement Authority	☐ Transmission Operator
☐ Distribution Provider	☐ Transmission Owner
☐ Generator Operator	☐ Transmission Planner
☐ Generator Owner	☐ Transmission Service Provider
☐ Interchange Coordinator	☐ Purchasing-Selling Entity
☐ Load-serving Entity	☐ Resource Planner
☐ Market Operator (Resource Integrator)	☐ Reliability Coordinator
☐ Reliability Assurer	☐ Standards Developer

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.

Name:	Office Telephone:
Organization:	E-mail:
Name:	Office Telephone:
Organization:	E-mail:

[1] These functions are defined in the NERC Functional Model, which is downloadable from the NERC Web site.

Non-Standard

Regional Standard:
PRC-002-NPCC-01

Disturbance Monitoring
Current Status:
Regional BOD Approved

View Supporting Documents

Approval & Implementation

Date	Action	
04/28/16	Approval Supporting Document posted publicly **(10)**	View Document
04/28/16	Approval Supporting Document posted publicly **(9)**	View Document
03/23/16	Region BOD Approval	

Ballot Period 11/16/2015 through 11/26/2015

Date	Action	
11/26/15	Ballot Period Ended	View Ballot Results
11/16/15	Ballot Period Started	View Ballot Submissions
11/16/15	Membership Ballot Document posted publicly **(8)**	View Document

Project Initiation / Drafting Team Formation

Date	Action	
02/23/15	RSAR Document posted publicly **(7)**	View Document
02/18/15	RSC Accepts	

Information in a Regional Standard Authorization Request (RSAR)

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

Regional Standard Authorization Request Form

Title of Proposed Standard:	PRC-002-NPCC-02
Request Date:	02-18-2015

RSAR Requester Information

		RSAR Type (Check box for one of these selections.)	
Name:	Paul DiFilippo		
Company:	NPCC	☐	New Standard
Telephone:	416-345-5042	☒	Revision to Existing Standard
Fax:		☐	Withdrawal of Existing Standard
Email:	paul.difilippo@HydroOne.com	☐	Urgent Action

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

The purpose of the proposed RSAR is to review the regional standard for potential revisions made necessary by the industry's adoption of the new NERC BES definition, the Paragraph 81 directive, and the development of NERC's PRC-002-2 Disturbance Monitoring and Reporting Requirements standard. Retiring PRC-002-NPCC-01 is to be considered if it is determined that it can be retired without sacrificing the ability to capture post-disturbance data.

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

To enhance efficiencies and cost effectiveness, it must be determined if PRC-002-NPCC-01requirements should be revised or retired to address the new NERC BES definition, to incorporate Paragraph 81, and to eliminate redundancy leading to double jeopardy with PRC-002-2 requirements without sacrificing the ability to capture post-disturbance data.

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

The requirements in PRC-002-NPCC-01 will be reviewed individually for revision or deletion with respect to the new NERC BES definition and Paragraph 81. In addition, PRC-002-NPCC-01 will be reviewed against NERC's PRC-002-2. PRC-002-2 mandates the capturing of adequate data to facilitate the analysis of BES disturbances. This "umbrella" encompasses the relevant requirements in PRC-002-NPCC-01. However, the relevant requirements in each of the standards are to be compared and the requirements of PRC-002-NPCC-01, if so determined, will be revised or deleted to eliminate redundancy and the concomitant double jeopardy. The review will be governed by bullet 1 of the NERC Rules of Procedure, Section 312, Regional Reliability Standards, which reads "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."

After this review is completed, it will be determined if PRC-002-NPCC-01 should be revised, or retired.

Reliability Functions

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

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

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check all boxes that apply.)*	
☒	1. Interconnected bulk 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.
Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*	
Recognizing that reliability is an Common Attribute of a robust North American economy:	
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes	

2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

Review PRC-002-NPCC-01against PRC-002-2 to determine if revisions are necessary or retirement of PRC-002-NPCC-01 is possible.

Related Standards

Standard No.	Explanation
PRC-002-2	NERC Disturbance Monitoring and Reporting Requirements standard

Related SARs or RSARs

SAR ID	Explanation
RSAR--11/26/12	RSAR for PRC-002-NPCC-01 to be reviewed with respect to the revised BES definition (withdrawn).

NORTHEAST POWER COORDINATING COUNCIL, INC.
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November 16, 2015

Subject: Notification of (10) Day Ballot Period for Retirement of Regional Standard PRC-002-NPCC-01 Disturbance Monitoring

Dear Madam/Sir:

On October 8, 2015, in accordance with the NPCC Regional Standards Process Manual (RSPM), the NPCC Regional Standards Committee (RSC) acting on the recommendation of the PRC-002-NPCC-01 Drafting Team, initiated the process to retire NPCC Regional Standard PRC-002-NPCC-01 Disturbance Monitoring.

The PRC -002-NPCC-01 standard drafting team was convened to address an RSC approved Regional Standard Authorization Request (RSAR) which proposed retiring PRC -002-NPCC-01 subsequent to FERC approval of PRC -002-2 *Disturbance Monitoring and Reporting Requirements*. PRC-002-2 was approved by the FERC on September 25, 2015 without any directives issued.

In accordance with the RSPM the retirement of PRC -002-NPCC-01 must be initially approved by the NPCC Full and General Members, with subsequent approvals by the NPCC Board of Directors, NERC Board of Trustees and finally filing with the applicable governmental authorities.

The PRC-002-NPCC-01 standard and all supporting documentation have been posted on the NPCC Website for a ten (10) day ballot period beginning November 16th, 2016.
https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=120

Please contact me with any questions.

Thank you.

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

A. Introduction

1. **Title:** **Disturbance Monitoring**

2. **Number:** PRC-002-NPCC-01

3. **Purpose:** Ensure that adequate disturbance data is available to facilitate Bulk Electric System event analyses. All references to equipment and facilities herein unless otherwise noted will be to Bulk Electric System (BES) elements.

4. **Applicability:**

   4.1. Transmission Owner

   4.2. Generator Owner

   4.3. Reliability Coordinator

5. **(Proposed) Effective Date:** To be established.

B. Requirements

R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SOE) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of Fault recording equipment. This capability shall: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island.

Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity.

1.2 Monitor the following at each location listed in 1.1:

1.2.1 Transmission and Generator circuit breaker positions

1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1.

1.2.3 Teleprotection keying and receive

R2. Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

2.1 All transmission lines.

2.2 Autotransformers or phase-shifters connected to busses.

2.3 Shunt capacitors, shunt reactors.

2.4 Individual generator line interconnections.

2.5 Dynamic VAR Devices.

2.6 HVDC terminals.

R3. Each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R4. Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (GSU) transformer to a Bulk Electric System Element unless Fault recording capability is already provided by the Transmission Owner. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R5. Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

5.1 Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.)

5.2 Three phase currents and neutral currents.

5.3 Polarizing currents and voltages, if used.

5.4 Frequency.

5.5 Real and reactive power.

R6. Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

6.1 Each Fault recorder record duration shall be a minimum of one (1) second.

6.2 Each Fault recorder shall have a minimum recording rate of 16 samples per cycle

6.3 Each Fault recorder shall be set to trigger for at least the following:

6.3.1 Monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups.

6.3.2 Neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current.

6.3.3 Monitored phase undervoltage set at 0.85 pu or greater.

6.4 Document additional triggers and deviations from the settings in 6.3.2 and 6.3.3 when local conditions dictate.

R7. Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

7.1 Provides a minimum of 1 DDR per 3,000 MW of peak Load.

7.2 Records dynamic disturbance information with consideration of the following facilities/locations:

7.2.1 Major Load centers.

7.2.2 Major Generation clusters.

7.2.3 Major voltage sensitive areas.

7.2.4 Major transmission interfaces.

7.2.5 Major transmission junctions.

7.2.6 Elements associated with Interconnection Reliability Operating Limits (IROLs).

7.2.7 Major EHV interconnections between operating areas.

R8. Each Reliability Coordinator shall specify that DDRs installed, after the approval of this standard, function as continuous recorders. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R9. Each Reliability Coordinator shall specify that DDRs are installed with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

9.1 A minimum recording time of sixty (60) seconds per trigger event.

9.2 A minimum data sample rate of 960 samples per second, and a minimum data storage rate for RMS quantities of six (6) data points per second.

9.3 Each DDR shall be set to trigger for at least one of the following (based on manufacturers' equipment capabilities):

9.3.1 Rate of change of Frequency.

9.3.2 Rate of change of Power.

9.3.3 Delta Frequency (recommend 20 mHz change).

9.3.4 Oscillation of Frequency.

R10. Each Reliability Coordinator shall establish requirements such that the following quantities are monitored or derived where DDRs are installed: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

10.1 Line currents for most lines such that normal line maintenance activities do not interfere with DDR functionality.

10.2 Bus voltages such that normal bus maintenance activities do not interfere with DDR functionality.

10.3 As a minimum, one phase current per monitored Element and two phase-to-neutral voltages of different Elements. One of the monitored voltages shall be of the same phase as the monitored current.

10.4 Frequency.

10.5 Real and reactive power.

R11. Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and

report this to the Regional Entity (RE) upon request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R12. Each Reliability Coordinator shall specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R13. Each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR shall acquire and install the DDR in accordance with R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R14. Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

14.1 Maintenance and testing intervals and their basis.

14.2 Summary of maintenance and testing procedures.

14.3 Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)).

14.4 Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center).

14.5 Monthly verification of active analog quantities.

14.6 Verification of DDR and DFR settings in the software every six (6) years.

14.7 A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.

R15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

15.1 NERC, Regional Entity, Reliability Coordinator.

15.2 Request from other Transmission Owners, Generator Owners within NPCC.

R16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

16.1 The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111.

16.2 Disturbance Data files shall be named in conformance with the latest revision of IEEE Standard C37.232.

16.3 Fault Recorder and DDR Files shall contain all monitored channels. SOE records shall contain station name, date, time resolved to milliseconds, SOE point name, status.

R17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall maintain, record and provide to the Regional Entity (RE), upon request, the following data on the DMEs installed to meet this standard: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

17.1 Type of DME.

17.2 Make and model of equipment.

17.3 Installation location.

17.4 Operational Status.

17.5 Date last tested.

17.6 Monitored Elements.

17.7 All identified channels.

17.8 Monitored electrical quantities.

C. Measures

M1. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Sequence of Event recording capability in accordance with 1.1 and 1.2. (R1)

M2. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 2.1 to 2.6. (R2)

M3. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability that determined the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements in accordance with R3.

M4. Each Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability for its Generating Plants at and above 200 MVA Capacity in accordance with R4.

M5. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it records for Faults, sufficient electrical quantities for each monitored Element to determine the parameters listed in 5.1 to 5.5. (R5)

M6. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 6.1 to 6.4. (R6)

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it established its area's requirements for Dynamic Disturbance Recording (DDR) capability in accordance with 7.1 and .2. (R7)

M8. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs installed after the approval of this standard function as continuous recorders. (R8)

M9. Each Reliability Coordinator shall have, and provide upon request, evidence that it developed DDR setting triggers to include the parameters listed in 9.1 to 9.3. (R9)

M10. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs monitor the Elements listed in 10.1 through 10.5. (R10)

M11. Each Reliability Coordinator shall have, and provide upon request, evidence that it documented additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10. (R11)

M12. Each Reliability Coordinator shall have, and provide upon request, evidence that it specified its DDR requirements which included the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners in the Reliability Coordinator's area. (R12)

M13. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it acquired and installed the DDRs in accordance with the specifications contained in the Reliability Coordinator's request, and a mutually agreed upon implementation schedule. (R13)

M14. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it has a maintenance and testing program for stand alone DME

(equipment whose only purpose is disturbance monitoring) that meets the requirements in 14.1 through 14.7. (R14)

M15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided recorded disturbance data from DMEs within 30 days of the receipt of the request from the entities listed in 15.1 and 15.2. (R15)

M16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it submitted the data files in a format that meets the requirements in 16.1 through 16.3. (R16)

M17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it maintained a record of and provided to NPCC when requested, the data on DMEs installed meeting the requirements 17.1 through 17.8. (R17)

D. 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 Transmission Owner and Generator Owner shall keep evidences for three calendar years for Measures 1, 5, 6, 13, 16 and 17.

The Transmission Owner shall keep evidence for three years for Measures 2 and 3.

The Generator Owner shall keep evidence for three years for Measure 4.

The Reliability Coordinator shall keep evidence for three years for Measures 7, 8, 9, 10, 11, 12, 16 and 17.

The Transmission Owner and Generator Owner shall keep evidences for twenty-four calendar months for Measures 14 and 15.

The Reliability Coordinator shall keep evidence for twenty-four calendar months for Measure 15.

If a Transmission Owner, Generator Owner or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit and all subsequent record.

1.4. Compliance Monitoring and Assessment Processes

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting
- Compliance Violation Investigations
- Complaints

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1 The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed…	Up to and including 10% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 10% and up to and including 20% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 20% and up to and including 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.
R2 The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed…	Up to and including 10% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 10% and up to and including 20% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 20% and up to and including 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.
R3 The Transmission	Not applicable.	Not applicable.	Not applicable.	Fault recording capability that determines the

Owner failed to provide…				current zero time for loss of transmission Elements.
R4 The Generator Owner failed to provide Fault recording capability at…	Up to and including 10% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 10% and up to and including 20% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 20% and up to 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.
R5 The Transmission Owner or Generator Owner failed to record for the Faults…	Up to and including 10% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 10% and up to and including 20% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 20% and up to and including 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.
R6 The Transmission Owner or Generator Owner failed …	To provide Fault recording capability for up to and including 10% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1	To provide Fault recording capability for more than 10% and up to and including 20% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or	To provide Fault recording capability for more than 20% and up to and including 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in	To provide Fault recording capability for more than 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than ten (10) locations.

	through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for up to 2 locations.	deviations from the settings stipulated in 6.3 through 6.4 for more than two (2) and up to and including five (5) locations.	6.3 through 6.4 for more than five (5) and up to and including ten (10) locations.	
R7 The Reliability Coordinator failed to establish its area's requirements for…	Up to and including 10% of the required DDR coverage for its area as per 7.1and 7.2.	More than 10% and up to and including 20% of the required DDR coverage for its area as per 7.1 and 7.2.	More than 20% and up to and including 30% of the required DDR coverage for its area as per 7.1 and 7.2.	More than 30% of the required DDR coverage for its area as per 7.1 and 7.2.
R8 The Reliability Coordinator failed to specify that DDRs installed…	Not applicable.	Not applicable.	Not applicable.	Function as continuous recorders.
R9 The Reliability Coordinator failed to specify that DDRs are installed without…	Not applicable.	Not applicable.	Not applicable.	The capabilities listed in 9.1 through 9.3.
R10 The Reliability Coordinator failed to ensure that the quantities listed in are monitored or derived…	Not applicable. 10.1 through 10.5	Not applicable.	Not applicable.	Where DDRs are installed.
R11 The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings from the required trigger settings described in R9	Up to two (2) facilities within the Reliability Coordinator's area that have a DDR. and deviations	More than two (2) and up to five (5) facilities within the Reliability Coordinator's area that have a DDR.	More than five (5) and up to ten (10) facilities within the Reliability Coordinator's area that have a DDR.	More than ten (10) facilities within the Reliability Coordinator's area that have a DDR.

and the required list of monitored quantities as described in R10 for…				
R12 The Reliability Coordinator failed to specify to the Transmission Owners and Generator Owners its DDR requirements including the DDR setting triggers established in R9 but missed…	Not applicable.	Not applicable.	Not applicable.	Established setting triggers.
R13 The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for…	Up to and including 10% of the requirement set of the Reliability Coordinator's request to install DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 10% and up to 20% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 20% and up to 30% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 30% of the requirement set requested by the Reliability Coordinator and installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR OR The Reliability Coordinator, Transmission Owners, and Generator Owners failed to mutually agree on an implementation schedule.
R14 The Transmission Owner or Generator Owner…	Established a maintenance and testing program for stand alone DME but provided incomplete data for any one (1) of 14.1 through	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than one (1) and up to and including three (3) of 14.1 through 14.7.	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than three (3) and up to and including six (6) of 14.1 through 14.7.	Did not establish any maintenance and testing program for DME; OR The Transmission Owner or Generator Owner established a maintenance and testing program for DME but did not provide any data that

	14.7.			meets all of 14.1 through 14.7.
R15 The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for…	Up to and including fifteen (15) days in meeting the requests of an entity, or entities in 15.1, or 15.2.	More than fifteen (15) days but less than and including thirty (30) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than 30 days but less than and including forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.
R16 The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit…	Up to and including two (2) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than two (2) and up to and including five (5) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than five (5) and up to and including ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.
R17 The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity , upon request…	Up to and including two (2) of the items in 17.1 through 17.8.	More than two (2) and up to and including four (4) of the items in 17.1 to 17.8.	More than four (4) and up to and including six (6) of the items in 17.1 through 17.8.	More than six (6) of the items in 17.1 through 17.8.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	November 4, 2010	Adopted by NERC Board of Trustees	New
1	October 20, 2011	FERC Order issued approving PRC-002-NPCC-01 (FERC's Order became effective on October 20, 2011)	

NPCC Disturbance Monitoring Drafting Team WebEx/Call
Draft Minutes

August 13, 2015 01:00 p.m. - 03:00 p.m.

Call in 1-415-655-0003
Access Code 642 003 478
WebEx Password dmsdt

1. **Welcome-Introductions**
   Lee Pedowicz made opening remarks and introduced the participants on the call.

   Participants--Drafting Team Members
   Robert Pellegrini
   Tim Kucey
   Robert Grabovickic
   Jim Watson
   Brian Evans-Mongeon
   Lee Pedowicz
   RuiDa Shu
   Don Burkart
   Daniel Kidney
   George Wegh

   Observers
   Dave Bertagnolli
   Kelly Dash
   Po Bun Ear
   Juan Villar
   Brian Robinson

2. NPCC Antitrust Compliance Guidelines

Lee Pedowicz read the NPCC Antitrust Compliance Guidelines.

3. Review Standard/Criteria Comparison Table

Bob Pellegrini went over the objectives of the RSAR. Consideration was to be given to retiring PRC-002-NPCC-01 because of the NERC approval of PRC-002-2 (now pending with FERC). It was mentioned that Criteria A-15 was stay in place. George Wegh commented that A-15 will continue to exist because some Canadian entities did not accept PRC-002-NPCC-01. Bob Pellegrini added that A-15 might need refreshing.

PRC-002-NPCC-01 Requirement R1 was discussed.

Juan Villar commented that if it is decided to retire PRC-002-NPCC-01, then there must be an explanation in the petition to FERC as to why it is not needed.

Meeting participants said that the BES is more encompassing than NPCC's Criteria A-10 BPS.

Several participants shared the results of their internal assessments of SOE/DFR coverage differences between PRC-002-NPCC-01 and PRC-002-2. In each case the PRC-002-NPCC-01 standard was inclusive of the PRC-002-2 requirements, and in the majority of cases PRC-002-NPCC-01 required DME at 2 to 3 times the number of locations that PRC-002-2 required. The adequacy of data capture for event analysis obtainable from PRC-002-2, PRC-002-NPCC-01, and A-15 was discussed.

The intention of PRC-002-NPCC-01 was to have it applicable to BPS Elements. At the time of its writing, the formal NERC BES definition that is in force today did not exist. BES versus BPS will be an issue.

Bob Pellegrini felt that reliability would be diminished by not having a regional standard.

Lee Pedowicz will find out how enforceable is NPCC Criteria.

The question was raised as to whether or not PRC-002-2 and A-1 would be adequate to obtain disturbance monitoring data.

The question of whether refreshing A-15 would aid in the retirement of PRC-002-NPCC-01 was discussed. It was suggested to revise A-15 to fill in any reliability gaps presented by the retirement of PRC-002-NPCC-01 with PRC-002-2 being in place.

George Wegh said that TFSP will be looking to the Drafting Team to develop recommendations for revisions necessary in A-15. TFSP will be responsible for revising the A-15 Criteria document and possibly including it as part of a new directory.

How enforceable is A-15? It was felt that it applied to a smaller number of entities.

The Drafting Team will make changes to the provided table to align the necessary comparisons.

4. Next Steps

Another WebEx is planned for August 28, 2015 9:00 a.m. - 11:00 a.m. At that WebEx information on the enforceability of NPCC Criteria will be presented. Attendees should have hard copies of A-15, PRC-002-2, PRC-002-NPCC-01, and the Table to refer to, to facilitate comparisons.

5. Future Meetings

a. WebEx
   Planned for Friday, August 28, 2015 from 9:00 a.m. - 11:00 a.m.
b. In person
   Face-to-face meetings to be scheduled as needed.

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 Disturbance Monitoring Drafting Team WebEx/Call
Draft Minutes

August 28, 2015 09:00 a.m. - 11:00 a.m.

Call in 1-415-655-0003
Access Code 642 003 478
***WebEx Password* Disturbance**

1. **Welcome-Introductions**
   Lee Pedowicz made opening remarks and introduced the participants on the call.

   Participants--Drafting Team Members
   Robert Pellegrini
   Tim Kucey
   Robert Grabovickic
   Jim Watson
   Lee Pedowicz
   RuiDa Shu
   Daniel Kidney
   George Wegh
   Paul Difilippo

   Observers
   Dave Bertagnolli
   Kelly Dash
   Juan Villar
   Scott Nied--NPCC Compliance
   Brian Robinson

2. **NPCC Antitrust Compliance Guidelines**
   Lee Pedowicz read the NPCC Antitrust Compliance Guidelines.

3. **NPCC's Scott Nied--Compliance to call in to respond to enforceability questions**

Scott Nied, NPCC compliance called in. Bob Pellegrini asked Scott about the compliance and enforceability implications of retiring PRC-002-NPCC-01, making a new directory for Disturbance Monitoring, and revising A-15. Scott Nied replied that because PRC-002-NPCC-01 is FERC approved, Compliance only enforces PRC-002-NPCC-01 if an entity has a NERC Compliance Registry (NCR) numbers. Full Members have to comply with Criteria and Directories. This compliance is a voluntary obligation, and is validated by a signed document. Brian Robinson asked what are the ramifications if you don't comply? Scott Nied answered that for Full Members this is self-policing.

Bob Pellegrini asked the Drafting Team if it would be in favor of retiring PRC-002-NPCC-01, do a gap analysis and give to TFSP to revise A-15, or develop a directory. Dave Bertagnolli agreed with that course of action.

Brian Robinson asked that if it came down to a variance of the as of yet not FERC approved PRC-002-2, could it be handled with NPCC's Regional Standard Processes Manual procedure as is being done with PRC-006? Lee Pedowicz was going to find out.

A discussion of retiring PRC-002-NPCC-01 began centering on how to justify the retirement of PRC-002-NPCC-01. Justification is that A-15 and a possible new directory would be more stringent.

4. **Review Standard/Criteria Comparison Table**

The comparison table was gone over. Paul Difilippo commented that there would be less disturbance monitoring coverage on BPS buses and generators without PRC-002-NPCC-01. A-15 would close any gaps.

George Wegh commented that the Drafting Team would have to make a recommendation on what would have to be revised in A-15.

Juan Villar commented that he liked the approach of retiring PRC-002-NPCC-01. He agreed that any gaps between PRC-002-2 and PRC-002-NPCC-01 could be addressed in A-15.

Any redundancies between A-15 and PRC-002-2 would have to be eliminated. It was suggested that the DDR section in A-15 could be removed~~.~~ since PRC-002-2 is far more inclusive than A-15.

4. **Next Steps**

The next WebEx is planned for September 11, 2015 1:00 p.m. - 3:00 p.m.

5. Future Meetings

a. WebEx

Planned for Friday, September 11, 2015 August 28, 2015 from 1:00 p.m. - 3:00 p.m.

b. In person

Face-to-face meetings to be scheduled as needed.

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

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 Disturbance Monitoring Drafting Team WebEx/Call
Minutes

September 11, 2015 01:00 p.m. - 03:00 p.m.

Call in 1-415-655-0003
Access Code 642 003 478
***WebEx Password* Disturbance**

Summary--it was decided by the meeting to retire PRC-002-NPCC-01, and have a new directory developed. FERC will be considering PRC-002-2 at its upcoming September 17, 2015 meeting.

1. **Welcome-Introductions**
   Lee Pedowicz made opening remarks and introduced the participants on the call.

   Participants--Drafting Team Members
   Robert Pellegrini
   Lee Pedowicz
   RuiDa Shu
   Daniel Kidney
   George Wegh
   Paul Difilippo

   Observers
   Dave Bertagnolli
   Kelly Dash
   Juan Villar
   Brian Robinson

2. **NPCC Antitrust Compliance Guidelines**
   Lee Pedowicz read the NPCC Antitrust Compliance Guidelines.

3. **Review Standard/Criteria Comparison Table**

a. Revise A-15, or develop a directory

Lee Pedowicz gave a summary of how PRC-002-NPCC-01 can be handled--replace with a directory (and what would comprise a directory in terms of including B and C documents), revise Criteria A-15, or revise PRC-002-NPCC-01.

Robert Pellegrini asked for opinions on retiring PRC-002-NPCC-01 and developing a directory.

Lee Pedowicz discussed the directory development process, and referred the meeting to NPCC's Directory Development and Revision Manual.

Lee Pedowicz will handle all the administrative details going forward.

George Wegh led a discussion on a Directory addressing NPCC's BPS versus the continent-wide standard covering the BES. A discussion ensued over the possibility of overlapping requirements (there should not be redundancy between requirements) between PRC-002-2 and a new NPCC directory. The directory would have the more stringent requirements. From page 4 of NPCC's Directory Development and Revision Manual directed that "…an initial translation of the existing criteria document was performed in addition to identifying and eliminating language within the criteria that duplicated existing NERC Reliability Standards." Redundancy is to be avoided to ensure that there cannot be multiple violations because of the violation of one requirement.

Lee Pedowicz is going to get information on an overlap between Directory #1 and the relevant continent-wide standards.

Robert Pellegrini stated that because PRC-002-2 is more stringent for DDR, NPCC will follow PRC-002-2. This was agreed with by the meeting.

Lee Pedowicz mentioned that FERC will be discussing PRC-002-2 at its upcoming September 17, 2015 meeting. He will send electronically distribute FERC's announcement of the meeting, and send the Drafting Team its decision on PRC-002-2.

The question was raised regarding how compliance with PRC-002-NPCC-01 would be enforced by NPCC while the standard was being considered for retirement by FERC. Brian Robinson said that the precedent has been set for having standards not actively monitored by NPCC Compliance. Lee Pedowicz will check with NPCC Compliance to see how they would approach enforcing PRC-002-NPCC-01while it was with FERC for retirement consideration, but

before it was officially retired, and see if it could be taken off the actively monitored list.

The development of a new directory would be given by NPCC to an outside contractor. That draft would be used as the foundation for its formal development.

Lee Pedowicz asked what the Drafting Team's role will be during this process, and George Wegh mentioned that review of the directory's development would be taken over by TFSP.

Lee Pedowicz to call in to the TFSP meeting September 16, 2015 to give an update on Disturbance Monitoring. (Note: George Wegh addressed PRC-002-NPCC-01 and Lee Pedowicz did not have to call in.)

4. Next Steps

Lee Pedowicz will handle the administration of the retirement of PRC-002-NPCC-01, and the development of a directory.

5. Future Meetings

a. WebEx--will be held if necessary.
b. In person

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.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
LOCATIONS FOR DATA CAPTURE (SER, FR) R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SER) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of Fault recording equipment. This capability shall: 1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island. Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity. 1.2 Monitor the following at each location listed in 1.1: 1.2.1 Transmission and Generator circuit breaker positions 1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1. 1.2.3 Teleprotection keying and receive R2. Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: **2.1** All transmission lines. **2.2** Autotransformers or phase-shifters connected to busses. **2.3** Shunt capacitors, shunt reactors. **2.4** Individual generator line interconnections. **2.5** Dynamic VAR Devices. **2.6** HVDC terminals. **R7.** Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance	**LOCATIONS FOR DATA CAPTURE (SER, FR)** R1. Each Transmission Owner shall: 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1. 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data. 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.	**LOCATIONS FOR DATA CAPTURE (SER, FR)** 3.2. Sequence of Event recorders shall be provided at all **bulk power system** substations and at generating units above 50 MW **capacity**, and at generating plants above 300 MW **capacity** 4.3 **Fault** recording capability shall be provided by the GO for generating units above 200 MW **capacity**. 4.4 **Fault** recorders shall monitor the following **elements** at each location where **fault** recorders are installed: - All **BPS** Transmission Lines - Autotransformers or phase-shifters connected to **BPS** busses - Shunt capacitors 345 kV and above - Individual generator interconnections - Dynamic Var Devices - HVDC Terminals - A Transmission Owner may optionally include the monitoring of transformers serving load from a **BPS** bus. 5.2 On an **Area** basis, there shall be at least ten (10) DDRs per 30,000 MW of peak **load**, distributed throughout the system, and installed at various types of locations, with consideration given to the following factors: - Major **load** centers - Major **generation** clusters - Major voltage sensitive areas - Major transmission interfaces - Major transmission junctions - **Elements** associated with Interconnection Reliability Operating Limits (IROLs) - Major EHV interconnections between control areas. 5.3 An evaluation of the need for a DDR should be made upon each new major **BPS** installation and upon each bulk power system station addition or expansion where a **fault** recorder replacement project is being made. (A field for this purpose will be included in the next revision of Document C-22.) 5.4 DDRs shall monitor the following **elements** at each location where dynamic recorders are installed: - Most lines such that normal maintenance	Because of its Attachment 1 Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data in PRC-002-2, PRC-002-2 does not require SER coverage at as many buses as PRC-002-NPCC-01. There is no FR or SER required by PRC-002-2 from generators. Locations requiring monitoring in PRC-002-NPCC-01 were amended by Compliance Guidance Statements CGS-002 Defining Generator Materiality for Registration dated May 4, 2009 (to be retired 7/1/16), CGS-004 Generating Plant Capacity in PRC-002-NPCC-01 dated March 20, 2013, and CGS-005 Clarification of Monitoring and Enforcement of PRC-002-NPCC-01.	Specifics provided in the sections below on SOE (PRC-002-NPCC-01), SER (PRC-002-2), Fault recording (FR), and DDR.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
Recording (DDR) capability that: **7.1** Provides a minimum of 1 DDR per 3,000 MW of peak Load. **7.2** Records dynamic disturbance information with consideration of the following facilities/locations: **7.2.1** Major Load centers. **7.2.2** Major Generation clusters. **7.2.3** Major voltage sensitive areas. **7.2.4** Major transmission interfaces. **7.2.5** Major transmission junctions. **7.2.6** Elements associated with Interconnection Reliability Operating Limits (IROLs). **7.2.7** Major EHV interconnections between operating areas.		activities do not interfere with DDR requirements. - Bus voltages		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
SOE R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SER) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of Fault recording equipment. This capability shall: 1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island. Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity. 1.2 Monitor the following at each location listed in 1.1: 1.2.1 Transmission and Generator circuit breaker positions 1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1. 1.2.3 Teleprotection keying and receive	**SER** R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses.	**SOE** 3.2. Sequence of Event recorders shall be provided at all **bulk power system** substations and at generating units above 50 MW **capacity**, and at generating plants above 300 MW **capacity** 3.3. Sequence of Events recording shall monitor the following at each location: - Transmission and Generator circuit breaker positions - **Protective Relay** tripping for all **protection groups** - **Teleprotection** keying & receive	PRC-002-NPCC-01 is more specific and inclusive in the locations (substations and generating units) where SOE is to be provided (PRC-002-NPCC-01 Parts 1.1 and 1.2). Also more specific in that it specifies that SER is to be provided for protective relay tripping and teleprotection keying.	3.2--for generating units, 50MW to be changed to 50MVA, 300MW to 300MVA. Add radial loads greater than 300MW, or the operation of which creates a Generation/Load island. Bulk power system to be changed to Bulk Electric System.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
FAULT RECORDING **R2.** Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: **2.1** All transmission lines. **2.2** Autotransformers or phase-shifters connected to busses. **2.3** Shunt capacitors, shunt reactors. **2.4** Individual generator line interconnections. **2.5** Dynamic VAR Devices. **2.6** HVDC terminals. **R3.** Each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements. **R4.** Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (GSU) transformer to a Bulk Electric System Element unless Fault recording capability is already provided by the Transmission Owner. **R5.** Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following: **5.1** Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.) **5.2** Three phase currents and neutral currents. **5.3** Polarizing currents and voltages, if used. **5.4** Frequency. **5.5** Real and reactive power. **R6.** Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities: **6.1** Each Fault recorder record duration shall be a minimum of one (1) second. **6.2** Each Fault recorder shall have a minimum recording rate of 16 samples per cycle	**FAULT RECORDING** R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: 3.1 Phase-to-neutral voltage for each phase of each specified BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1 Transformers that have a low-side operating voltage of 100kV or above. 3.2.2 Transmission Lines. R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: 4.1 A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or • At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder. 4.2 A minimum recording rate of 16 samples per cycle. 4.3 Trigger settings for at least the following: 4.3.1 Neutral (residual) overcurrent. 4.3.2 Phase undervoltage or overcurrent.	**FAULT RECORDING** 4.1 **Fault** recording is the responsibility of transmission owners and **generation** owners. When adding or replacing a DFR at an existing BPS facility, the TO or GO should complete a notification in accordance with Document C-22. 4.2 **Fault** recording shall be provided by the TO to determine the current zero time for loss of **BPS** transmission **elements**. The current zero time shall be reported as the time of the final current zero on the last phase to interrupt. 4.3 **Fault** recording capability shall be provided by the GO for generating units above 200 MW **capacity**. 4.4 **Fault** recorders shall monitor the following **elements** at each location where **fault** recorders are installed: - All **BPS** Transmission Lines - Autotransformers or phase-shifters connected to **BPS** busses - Shunt capacitors 345 kV and above - Individual generator interconnections - Dynamic Var Devices - HVDC Terminals - A Transmission Owner may optionally include the monitoring of transformers serving load from a **BPS** bus. 4.5 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following: - Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.) - Three phase currents and neutral currents. - Polarizing currents and voltages, if used. - Frequency. - Active and reactive power. 4.6 **Fault** recorder record duration shall be a minimum of one (1) second. 4.7 **Fault** recorder minimum recording rate shall be 16 samples per cycle. 4.8 As a minimum, **fault** recorders shall be set to trigger for all the following functions:	Because of its Attachment 1 Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data, PRC-002-2 doesn't require SER coverage at as many buses as PRC-002-NPCC-01. Current Zero Time is not addressed in PRC-002-2. There NO FR required by PRC-002-2 from generators. PRC-002-2 does not require recording polarizing currents or voltages, frequency, and real and reactive power. PRC-002-NPCC-01 specifies a record duration of one (1) second. PRC-002-2 specifies "at least 30-cycles" or "two cycles of the pre-trigger data…and the final cycle of the fault…" PRC-002-NPCC-01 specifies fault recorder triggering for specified per unit values of rated CT secondary current, set per unit values of neutral (residual) overcurrent, specified undervoltage per unit value, and documentation of additional triggers when necessary.	Triggering for monitored phase overcurrent set at 1.5 pu or less. 4.4--Change BPS to BES Remove "345kV and above" from shunt capacitors Add shunt reactors 4.1--Change BPS to BES 4.2-- Change BPS to BES 4.3--Change MW to MVA 4.5--Change Active to Real 4.8--Add monitored phase overcurrent set at 1.5 pu or less of rated CT secondary current Add "or greater" to "Phase undervoltage set at 0.85 pu"

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
6.3 Each Fault recorder shall be set to trigger for at least the following: **6.3.1** Monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups. **6.3.2** Neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current. **6.3.3** Monitored phase undervoltage set at 0.85 pu or greater. **6.4** Document additional triggers and deviations from the settings in 6.3.2 and 6.3.3 when local conditions dictate.		- **Protective Relay** tripping for all **protection groups** - Neutral (residual) overcurrent set at 0.2 pu rated CT secondary current - Phase undervoltage set at 0.85 pu 4.9 When local conditions require different settings or additional functions, such situations shall be documented.		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
DYNAMIC DISTURBANCE RECORDING **R7.** Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: **7.1** Provides a minimum of 1 DDR per 3,000 MW of peak Load. **7.2** Records dynamic disturbance information with consideration of the following facilities/locations: **7.2.1** Major Load centers. **7.2.2** Major Generation clusters. **7.2.3** Major voltage sensitive areas. **7.2.4** Major transmission interfaces. **7.2.5** Major transmission junctions. **7.2.6** Elements associated with Interconnection Reliability Operating Limits (IROLs). **7.2.7** Major EHV interconnections between operating areas. **R8.** Each Reliability Coordinator shall specify that DDRs installed, after the approval of this standard, function as continuous recorders. **R9.** Each Reliability Coordinator shall specify that DDRs are installed with the following capabilities: **9.1** A minimum recording time of sixty (60) seconds per trigger event. **9.2** A minimum data sample rate of 960 samples per second, and a minimum data storage rate for RMS quantities of six (6) data points per second. **9.3** Each DDR shall be set to trigger for at least one of the following (based on manufacturers' equipment capabilities): **9.3.1** Rate of change of Frequency. **9.3.2** Rate of change of Power. **9.3.3** Delta Frequency (recommend 20 mHz change). **9.3.4** Oscillation of Frequency. **R10.** Each Reliability Coordinator shall establish requirements such that the following quantities are monitored or derived where DDRs are installed: **10.1** Line currents for most lines such that	**DYNAMIC DISTURBANCE RECORDING** R5. Each Responsible Entity shall: 5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: 5.1.1 Generating resource(s) with: 5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA. 5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA. 5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). 5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. 5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL). 5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. 5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: 5.2.1 One BES Element; and 5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. 5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. 5.4 Re-evaluate all BES Elements at least once	**DYNAMIC DISTURBANCE RECORDING** 5.1 Where the DDR capability is deemed necessary by the Reliability Coordinator, the Reliability Coordinator shall provide guidance in setting triggers and shall monitor the performance of the DDR devices. 5.2 On an **Area** basis, there shall be at least ten (10) DDRs per 30,000 MW of peak **load**, distributed throughout the system, and installed at various types of locations, with consideration given to the following factors: - Major **load** centers - Major **generation** clusters - Major voltage sensitive areas - Major transmission interfaces - Major transmission junctions - **Elements** associated with Interconnection Reliability Operating Limits (IROLs) - Major EHV interconnections between control areas. 5.3 An evaluation of the need for a DDR should be made upon each new major **BPS** installation and upon each bulk power system station addition or expansion where a **fault** recorder replacement project is being made. (A field for this purpose will be included in the next revision of Document C-22.) 5.4 DDRs shall monitor the following **elements** at each location where dynamic recorders are installed: - Most lines such that normal maintenance activities do not interfere with DDR requirements. - Bus voltages 5.5 As a minimum, DDRs shall monitor one phase current per monitored **element** and two phase-to-neutral voltages of different **elements**. One of the monitored voltages shall be of the same phase as the monitored current. 5.6 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following: - Voltage, current, and frequency - Active and reactive power 5.7 DDRs installed after January 1, 2009 shall function	For non-continuous recorders, PRC-002-2 specifies triggered record lengths of at least 3 minutes versus 60 seconds for PRC-002-NPCC-01 (R9). PRC-002-2 specifies an output recording rate of at least 30 times per second. PRC-002-NPCC-01 specifies a minimum data storage rate of 6 data points per second. PRC-002-2 specifies an off nominal frequency trigger (if used). PRC-002-2 is specific on the rate of change of frequency trigger values (if used). PRC-002-2 specifies an undervoltage trigger (if used). PRC-002-NPCC-01 specifies a rate of change of Power trigger (if used). PRC-002-NPCC-01 specifies a Delta Frequency trigger (if used), and an oscillation of Frequency trigger (if used). PRC-002-2 stipulates that normal line maintenance does not interfere with DDR functionality for monitoring line currents. PRC-002-2 stipulates that normal bus maintenance does not interfere with DDR functionality for monitoring bus voltages. PRC-002-NPCC-01 addresses DDR installation. PRC-002-2 does not address equipment.	5.1--Add "The Reliability Coordinator shall request DDR capability, and shall, with Transmission Owners, and Generator Owners mutually agree on an implementation schedule." 5.2--Change "control" to "operating". 5.3--Change BPS to BES Change "bulk power System" to Bulk Electric System 5.4--Revise first bullet to read "Lines and buses such that …" 5.4--"Bus voltages" should be "bus". 5.6--Change Active to real. Add 5.12: Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings and the required list of monitored quantities and report this to NPCC upon request.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
normal line maintenance activities do not interfere with DDR functionality. **10.2** Bus voltages such that normal bus maintenance activities do not interfere with DDR functionality. **10.3** As a minimum, one phase current per monitored Element and two phase-to-neutral voltages of different Elements. One of the monitored voltages shall be of the same phase as the monitored current. **10.4** Frequency. **10.5** Real and reactive power. **R11.** Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and report this to the Regional Entity (RE) upon request. **R12.** Each Reliability Coordinator shall specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners. **R13.** Each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR shall acquire and install the DDR in accordance with R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule.	every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan. R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 6.1 One phase-to-neutral or positive sequence voltage. 6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. 6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. 6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: 7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level. 7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current. 7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. 7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1. R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective	as continuous recorders. 5.8 Each device shall sample data at a rate of at least 960 samples per second (16 samples per cycle and shall store the RMS value of electrical quantities at a rate of at least 6 data points per second.) 5.9 The following DDR triggers shall be considered where available based on manufacturers capability: - Rate of change of Frequency - Rate of change of Power - Delta Frequency 20 mHz change - Oscillation of Frequency 5.10 When local conditions require different settings or additional functions, such situations shall be documented. 5.11 When DDR triggers are used, duration of triggered records shall be a minimum of sixty (60) seconds.		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
	date of this standard and is not capable of continuous recording, triggered records must meet the following: 8.1 Triggered record lengths of at least three minutes. 8.2 At least one of the following three triggers: • Off nominal frequency trigger set at: Low High o Eastern Interconnection <59.75Hz >61.0Hz o Western Interconnection <59.55Hz >61.0Hz o ERCOT Interconnection <59.35Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55Hz >61.5Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec >0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec >0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec >0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec >0.1875 Hz/sec • Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds. R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.			

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
TIME SYNCHRONIZATION **R14.** Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: **14.1** Maintenance and testing intervals and their basis. **14.2** Summary of maintenance and testing procedures. **14.3** Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)). **14.4** Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **14.5** Monthly verification of active analog quantities. **14.6** Verification of DDR and DFR settings in the software every six (6) years. **14.7** A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.	**TIME SYNCHRONIZATION** R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: 10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset. 10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.	**TIME SYNCHRONIZATION** **7.0 Time Synchronization** Internal clocks in DME devices shall be time synchronized to within 2 milliseconds or less of Coordinated Universal Time (UTC) scale. The time zone shall be clearly identified as either universal time zone or local time zone. **PRC-018-1 Requirement** R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements: R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar days.	PRC-002-2, and PRC-018-1 (to be retired 6 years after the implementation date for PRC-002-2) specify synchronization of ± 2 milliseconds and its coordination to UTC.	Section 6--Add 7.1: Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **NOTE: This is also in B-26 Guide for Application of Disturbance Recording Equipment**

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
DATA SPECIFICATIONS **R15.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases: **15.1** NERC, Regional Entity, Reliability Coordinator. **15.2** Request from other Transmission Owners, Generator Owners within NPCC. **R16.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements: **16.1** The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111. **16.2** Disturbance Data files shall be named in conformance with the latest revision of IEEE Standard C37.232. **16.3** Fault Recorder and DDR Files shall contain all monitored channels. SER records shall contain station name, date, time resolved to milliseconds, SER point name, status.	**DATA SPECIFICATIONS** **R11.** Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: **11.1** Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded. **11.2** Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor. **11.3** SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2. **11.4** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later. **11.5** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.	**DATA SPECIFICATIONS** 6.1 Recorded **disturbance** data from DMEs shall be forwarded within 30 days of receipt of the request in each of the following cases: - Request from NERC **Disturbance** Investigation Team - Request from NPCC **Disturbance** Investigation Team - Reliability Coordinator Request 6.2 Data forwarded shall be archived in its native format for a period of 3 years by the TO or GO. 6.3 **Disturbance** data files shall be provided in a format which is capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool (8). 6.4 Disturbance Data files shall be named in conformance with IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 6.5 **Fault** Recorder and DDR Files shall contain all monitored channels. SER records shall contain station, date, time resolved to milliseconds, SER point name, status. 6.6 Recorded data from each **disturbance** shall be retrievable for 10 calendar days. This requirement does not apply to **relays** unless those **relays** are designated as DME. **PRC-018-1 Requirement** R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements: R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar	PRC-002-2 stipulates 30 days unless an extension is granted. PRC-002-2 and PRC-018-1 stipulate that data is retrievable for 10 calendar days. PRC-002-2 is more specific on the data parameters. PRC-002-NPCC-01 is more specific as to the time resolution for SER data. PRC-018-1 stipulates archiving of data for at least three years. A-15 specifies archiving for 3 years. Note: PRC-018-1 is going to be retired in six years after the implementation period for PRC-002-2.	Section 6-- **NOTE: This is also in C-25 Procedure to Collect Power System Event Data for Analysis of System Performance**

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
		days. R4. The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4). R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
STATUS OF RECORDING CAPABILITY **R14.** Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: **14.1** Maintenance and testing intervals and their Basis. **14.2** Summary of maintenance and testing procedures. **14.3** Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)). **14.4** Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **14.5** Monthly verification of active analog quantities. **14.6** Verification of DDR and DFR settings in the software every six (6) years. **14.7** A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.	**STATUS OF RECORDING CAPABILITY** **R12.** Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: • Restore the recording capability, or • Submit a Corrective Action Plan (CAP) Regional Entity and implement it.	**STATUS OF RECORDING CAPABILITY** **8.0 Maintenance And Testing** Each TO, and GO shall establish a maintenance and testing program for DME (guidance for maintenance and testing is provided in Document B-26) that includes: • Maintenance and testing intervals and their basis. • Summary of maintenance and testing procedures. **PRC-018-1 Requirement** R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes: R6.1. Maintenance and testing intervals and their basis. R6.2. Summary of maintenance and testing procedures.		With the exception of PRC-002-NPCC-01 Part 14.4 (time synchronization), Requirement R14 to be added. **NOTE: This is also in B-26 Guide for Application of Disturbance Recording Equipment**

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
DATA ON THE DISTURBANCE MONITORING EQUIPMENT **R17.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall maintain, record and provide to the Regional Entity (RE), upon request, the following data on the DMEs installed to meet this standard: **17.1** Type of DME. **17.2** Make and model of equipment. **17.3** Installation location. **17.4** Operational Status. **17.5** Date last tested. **17.6** Monitored Elements. **17.7** All identified channels. **17.8** Monitored electrical quantities.	**DATA ON THE DISTURBANCE MONITORING EQUIPMENT** Not Applicable.	**DATA ON THE DISTURBANCE MONITORING EQUIPMENT** 6.7 The TO and GO shall each maintain and be ready to report to NPCC on request the following data on the DMEs installed to meet this standard: - Type of DME - Make and model of equipment - Installation location - Operational Status - Date last tested - Monitored **Elements** - Monitored Devices - Monitored Electrical Quantities **PRC-018-1 Requirement** R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1): R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder). R3.2. Make and model of equipment. R3.3. Installation location. R3.4. Operational status. R3.5. Date last tested. R3.6. Monitored elements, such as transmission circuit, bus section, etc. R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc. R3.8. Monitored electrical quantities, such as voltage, current, etc.	No gaps with PRC-018-1.	6.7--Revise "Monitored Devices" bullet to read "All identified channels"

NPCC, Inc.

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

October 16, 2015

Subject: Notification of Pre-Ballot Review for Retirement of Regional Standard PRC-002-NPCC-01 Disturbance Monitoring

Dear Madam/Sir:

On October 8, 2015 NPCC's Regional Standards Committee acting on the recommendation of the PRC-002-NPCC-02 Drafting Team, authorized the use of NPCC's standards process for retirement of NPCC Regional Standard PRC-002-NPCC-01 Disturbance Monitoring. The Drafting Team had been convened to address an approved Regional Standard Authorization Request (RSAR), and it decided that PRC-002-NPCC-01 could be retired dependent upon the FERC approval of continent-wide PRC-002-2 Disturbance Monitoring and Reporting Requirements. PRC-00-2 was approved by the FERC September 25, 2015 without any directives issued.

In accordance with the NPCC Regional Standard Processes Manual (RSPM), this authorization for retirement is to first be approved by the NPCC Members with subsequent approvals by the NPCC Board of Directors, NERC Board of Trustees, and then filing for approval of the retirement with the applicable governmental authorities. PRC-002-NPCC-01 and the Drafting Team's supporting document for the Standard's retirement have been merged into one document, and is posted on the NPCC Website for a thirty (30) day pre-ballot review period beginning this date. Immediately following the 30-day pre-ballot review a ten (10) day ballot period will commence. The 30-day Pre-Ballot Review, as currently posted, will close November 15, 2015.

The Standard/supporting document can be viewed at:

Retirement of PRC-002-NPCC-01 Disturbance Monitoring Authorized by NPCC's Regional Standards Committee

If you have any questions, please contact me.

Thank you.

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

March 31, 2016

To: NERC Board of Trustees

Subject: Request for Approval, Retirement of NPCC Regional Reliability Standard PRC-002-NPCC-01 *Disturbance Monitoring.*

On March 23, 2016 in accordance with the NPCC Regional Standard Processes Manual the NPCC Board of Directors approved the retirement of NPCC Regional Standard PRC-002-NPCC-01 *Disturbance Monitoring*.

The subject standard was originally adopted by the NERC Board of Trustees on November 4, 2010 and approved by the FERC on October 20, 2011. The standard was subject to enforcement on October 20, 2013. FERC recently approved the NERC continent-wide standard PRC-002-2 *Disturbance Monitoring and Reporting Requirements*, which becomes enforceable on July 1, 2016. NPCC participated in the development of the continent-wide standard and attributes of the Regional standard were incorporated into PRC-002-2.

Upon approval of the continent-wide standard by the FERC, NPCC's Task Force on System Protection, acting as a standard review/drafting team, initiated an analysis to determine if there was a reliability related need to maintain the Regional standard. The results of the review, as attached, indicated that the continent-wide standard's requirements were sufficient and redundant in their objectives with the Regional standard and identified where any differences are addressed by NPCC's existing more stringent reliability criteria.

Further, in accordance with the NERC "Regional Reliability Standards Evaluation Procedure 2.1", the proposal to retire the standard has been posted by NERC and no non-supportive comments were received.

Accordingly, NPCC is requesting that PRC-002-NPCC-01 be retired effective the later of July 1, 2016 or the date the retirement is approved by the applicable regulatory authorities. Contingent upon the approval of the NERC BOT, NPCC will work with NERC Legal Staff in order to prepare the necessary filings and petitions.

Thank you for your consideration.

Ruida Shu
Northeast Power Coordinating Council, Inc.
Senior Engineer, Reliability Standards and Criteria
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Direct: 917-934-7976
Fax: 212-302-2782
Email: rshu@npcc.org

PRC-002-NPCC-02 Disturbance Monitoring Draft Team Roster

Name:	Company:	Qualifications:
Don Burkart	Con Edison	Don has 5 years in relay protection engineering and have had countless experiences in system event analyses. Additionally, He is the Lead Disciple Engineer for the company wide DME programs.
Robert Grabovickic	National Grid	Responsibilities include the analysis of events and system disturbances, protection co-ordination studies, calculations of settings for protection relays and disturbance fault recorders (DFRs), configuration of DFRs for NY PMU project, reviewing the relay settings of generators owned by customers, the development of protection standards.
Tim Kucey	PSEG	Member of current NPCC PRC-002-NPCC review SDT (joined SDT in 2013 in response to membership solicitation). Co-lead of the "Tools and Training" team of the NERC investigation of the August 2003 Northeast Blackout. Responsible for the bulk of the team's findings/discoveries – and the associated write-ups in the NERC and US-Canada Bilateral Commission reports - regarding key entities' implementation, usage and the performance of system monitoring and analysis "tools" (e.g. EMS, RTCAs, SEs) involved in the incident. For the period 1994 through to 2002, technical positions with process and power industry DCS/EMS, SCADA and RTU OEMs: Fisher-Rosemount (now Emerson); Moore Process Control (now Siemens); GE Harris (previously Westronics, HDAP; now GE Power). NERC Manager of Enforcement and Mitigation from 2006 until 2010, then NERC's CEA agent (Manager of NOP Development) until late 2011. Duties included review of all compliance actions taken by NERC to the NERC BOT Compliance Committee, frequent engagement with the CCC and the Standards Committee, FERC staff, SDTs. Also involvement in several NERC events analyses/investigations and joint NERC-FERC 1B actions, typically involving transmission organizations, balancing authorities and reliability coordinators.
Brian Evans-Mongeon	Utility Services	As a prior member of the drafting team, he believe that he is qualified to serve again. He has been involved in numerous drafting teams including EOP-004, PRC-006 for both NPCC and NERC, BES, and Dispersed Generating Resources. He also serve on the NPCC RCC and the NERC PC, ERSTF, and RBRTF.
Robert Pellegrini	UI	Involved in designing P&C SCADA systems
Jim Watson	Dynergy	He has been employed in the electric utility industry for 33 years in the areas of generation operations, planning, and environmental compliance and for the last 4 years – NERC compliance.
George Wegh	Eversource	George has over 25 years of Electrical Engineering experience, of which 15 years have been in the utility industry. He is presently the Manager of Transmission Protection and Controls Engineering at Eversource Energy. He has been working in the Transmission Protection and Controls Department at Eversource Energy for over 8 years. He presently serve as the NPCC representative on the NERC System Protection and Controls Subcommittee (SPCS) and am Vice Chairman of the NPCC Task Force on System Protection (TFSP).
Paul Difilippo	Hydro One	28 years of experience in various aspects of protection systems at Hydro One including analysis of the 2003 Northeast blackout utilizing all available DME in Ontario. Member of TFSP since 2008 and current Chair. He is also the requester for the RSAR.
Ruida Shu	NPCC	NPCC Standards Staff. Ruida Shu has 8+ years of experience in

		Distribution, Transmission, SCADA, Construction, Daily Electric Operations, Facility Maintenance, Security, DOE/FEMA/APPA Grant Projects, Safety, Compliance and Reliability Standards.
Lee Pedowicz	NPCC	Manager of Reliability Standards at NPCC. Chair of PRC-002-2 Drafting Team. System operations real-time operating and outage scheduling, protective system testing, and substation design experience.
Daniel Kidney	NPCC	NPCC Compliance Staff. Daniel has been a member of the Compliance Enforcement staff at NPCC since 2014. Prior to joining NPCC, he was employed as a Transmission Planner at Central Maine Power.

NPCC, Inc.

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

December 2nd, 2015

NPCC Full and General Members:

In accordance with the NPCC Regional Standard Processes Manual the ballot period for the retirement of NPCC Regional Standard PRC-002-NPCC-01 Disturbance Monitoring closed at 23:59PM on November 26th, 2015.

The results of the ballot were as follows:

Quorum: 69% of the Total Registered
Approval: 97.10%

No negative ballots were received with comments therefore, in accordance with our Standards Processes Manual a recommendation for final Regional approval will be sent to the NPCC Board of Directors for consideration at their meeting on February 2, 2016.

Contingent upon the approval of the NPCC BOD, the proposal to retire PRC-002-NPCC-01 will be submitted to the NERC Board of Trustees with subsequent filings with the FERC and applicable provincial authorities.

Voting was conducted electronically and the full retirement record for the standard may be viewed at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=120

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	**19**	**15**	**0**	**14**	**0**	**1**
Central Hudson Gas and Electric Corporation	1	1		1		
Central Maine Power Company	1	1		1		
Consolidated Edison Company of New York, Inc.	1	1		1		
Emera Maine	1	1				1
Eversource	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 Transmission Corporation	1	1		1		
New Hampshire Transmission, LLC	1					
New York Power Authority	1	1		1		
New York State Electric & Gas	1					
Nova Scotia Power Inc.	1	1		1		
NStar Electric Company	1					
Orange and Rockland Utilities Inc	1	1		1		
Rochester Gas & Electric	1	1		1		
The United Illuminating Company	1	1		1		
Vermont Transco	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 System Operator	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**	**13**	**0**	**12**	**0**	**1**
Braintree Electric Light Department	1	1		1		
Consolidated Edison Company of New York, Inc.	1	1		1		
Eversource	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					
Long Island Power Authority	1	1		1		
Marblehead Municipal Light Department	1					
National Grid	1	1		1		
New York Power Authority	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		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	**22**	**17**	**0**	**17**	**0**	**0**
Consolidated Edison Company of New York, Inc.	1	1		1		
Covanta Energy	1	1		1		
Dominion Resources Inc.	1	1		1		
Dynegy, Inc.	1	1		1		
Entergy Nuclear Northeast	1	1		1		
Eversouce	1	1		1		
Exelon Generation	1	1		1		
First Wind Operations & Maintenance	1	1		1		
International Power America	1					
Long Island Power Authority	1					
Massachusetts Municipal Wholesale Electric Company	1	1		1		
New York Power Authority	1	1		1		
NextEra Energy Resources	1	1		1		
NRG Energy Inc.	1	1		1		
Nova Scotia Power Inc.	1	1		1		
Ontario Power Generation Inc.	1					
PSEG Power Connecticut, LLC	1	1		1		
PSEG Power New York, LLC	1	1		1		
Talen Energy Marketing, LLC	1	1		1		
TransCanada	1					
US Power Generating Company, 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	**14**	**8**	**0**	**8**	**0**	**0**
Brookfield Power Corporation	1	1		1		
Consolidated Edison Company of New York, Inc.	1	1		1		
Consolidated Edison Energy/Development	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					
New York Power Authority	1	1		1		
PSEG Energy Resources & Trade, LLC	1	1		1		
Shell Energy North America	1					
Utility Services Inc.	1	1		1		
Windy Bay Power, LLC	1					

NPCC Registered Members		1. Determine Quorum			2. Vote/Ballot Recording		
		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.	**7**	**4**	**0**		**4**	**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						
New York Power Authority	1	1			1		
New York State Department of Public Service	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	**13**	**7**	**0**	**7**	**0**	**0**
4g Technologies, LP	1					
Ascendant Energy Solutions, Inc.	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		
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					
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**	19	15	0	15	0.79
2	**Reliability Coordinators**	5	5	0	5	1.00
3	**TDUs, Dist. And LSE**	20	13	0	13	0.65
4	**Generator Owners**	22	17	0	17	0.77
5	**Marketers, Brokers, Aggragators**	14	8	0	8	0.57
6	**Customers- large and small**	7	4	0	4	0.57
7	**State and Provincial Reg. and Govt. Authorities**	13	7	0	7	0.54
		100	69	0	69	

Electronic Vote Quorum= at least 2/3 of the Total Registered

Quorum Present? **YES**

Determine if Motion or Item Passes

Sector	Sector Name	Total Registered	Sector % Attending	Affirmative # of Votes	Affirmative Fraction	Negative # of Votes	Negative Fraction	Abstain # of Votes	Votes Cast Total (-Abstentions)	Sector has Voted(1-Y, 0-N)
1	Transmission Owners	19	0.79	14	1.000	0	0.000	1	14	1
2	Reliability Coordinators	5	1.00	5	1.000	0	0.000	0	5	1
3	TDUs, Dist. And LSE	20	0.65	12	1.000	0	0.000	1	12	1
4	Generator Owners	22	0.77	17	1.000	0	0.000	0	17	1
5	Marketers, Brokers, Aggragators	14	0.57	8	1.000	0	0.000	0	8	1
6	Customers- large and small	7	0.57	4	1.000	0	0.000	0	4	1
7	State and Provincial Reg. and Govt. Authorities	13	0.54	7	1.000	0	0.000	0	7	1
	Totals	100		67	7.000	0	0.000	2	67	7
	Sum of Affirmative/Number of Sectors that Voted			1.000						
	MUST BE AT LEAST 2/3 to pass									
	Did MOTION PASS?			PASS						

REGIONAL STANDARDS COMMITTEE

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Sector (3) - Transmission Dependent Utilities ("TDUs"); Distribution Companies and Load-Serving Entities ("LSEs")

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Sector (4) - Generator Owners

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Sector (5) - Marketers, Brokers and Aggregators

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Sector 7 – Sub-Regional Reliability Councils, Customers and Other Regional Entities and Interested Entities

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Information in a Regional Standard Authorization Request (RSAR)

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

Regional Standard Authorization Request Form

Title of Proposed Standard:	PRC-006-NPCC-2
Request Date:	03-31-2015

RSAR Requester Information

Name: Brian Robinson		**RSAR Type (Check box for one of these selections.)**	
Company:	NPCC	☐	New Standard
Telephone: 802-241-1400		☒	Revision to Existing Standard
Fax:	(866) 214-8632	☐	Withdrawal of Existing Standard
Email:	Brian.Robinson@utilitysvcs.com	☐	Urgent Action

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

The purpose of the proposed RSAR is to review regional reliability standard PRC-006-NPCC-1 for potential revisions or retirements made necessary by NERC's PRC-006-1/PRC-006-2 Automatic Underfrequency Load Shedding and PRC-024-1/PRC-024-2 Generator Frequency and Voltage Protective Relay Settings standards.

PRC-006-NPCC-1 is to be reviewed to determine if the applicability of the standard needs to be revised in accordance with Project 2014-01 Dispersed Generation Resources.

PRC-006-NPCC-1 is to be reviewed in order to determine if the performance requirements as contained in the criteria of NPCC Directory#12 Sections 5.1.1 and 5.1.2 should be explicitly included in the requirements of the Regional Standard.

Attachment C in PRC-006-NPCC-1 is to be reviewed to address the implications of the design assessment, in accordance with Requirement R4 of PRC-006-1/PRC-006-2, of not meeting the program performance characteristics as identified in Requirement R3 of PRC-006-1/PRC-006-2.

PRC-006-NPCC-1 is to be reviewed in order to update Table 4 in Attachment C in accordance with the 2013 NPCC UFLS Adequacy Assessment. Additionally, the applicability of Requirements R4 and R5 will be reviewed to consider that Hydro Quebec is not part of the Eastern Interconnection.

Retiring PRC-006-NPCC-1 is to be considered if it is determined that it can be retired without sacrificing the ability to develop an effective underfrequency load shedding program.

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

To enhance efficiencies and cost effectiveness, it must be determined if PRC-006-NPCC-1 requirements can be revised or retired to address the new NERC BES definition, Paragraph 81, and eliminate redundancy leading to double jeopardy with PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 requirements without sacrificing the ability to develop an effective underfrequency load shedding program.

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

The requirements in PRC-006-NPCC-1 will be reviewed individually for revision or deletion with respect to the new NERC BES definition, and Paragraph 81. In addition, PRC-006-NPCC-1 will be reviewed against NERC's PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 2-2. PRC-006-1/PRC-006-2 mandates the establishment of design and documentation requirements for automatic underfrequency load shedding (UFLS) programs. PRC-024-1/PRC-024-2 mandate that Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions. These "umbrellas" encompasses the relevant requirements in PRC-006-NPCC-1. However, the relevant requirements in each of the standards are to be compared and the requirements of PRC-006-NPCC-1, if so determined, are revised or deleted to eliminate redundancy and the

concomitant double jeopardy. The review will also ensure that NERC Rules of Procedure, Section 312. Regional Reliability Standards, bullet 1that reads "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." will govern.

PRC-006-1/PRC-006-2 specifies in Requirement R4 that "Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years…" Revision to Attachment C of PRC-006-NPCC-1 needs to be considered to address the circumstance surrounding a design assessment that does not meet the performance characteristics as identified in Requirement R3 of PRC-006-1/PRC-006-2.

Revise Table 4 Attachment C to reflect the modified Quebec UFLS program parameters as recommended in the 2013 NPCC UFLS Adequacy Assessment and review the applicability of Requirements R4 and R5 as they pertain to the Quebec Interconnection.

Additionally, as identified by SS38 there are aspects of the performance requirements in NERC PRC-006-1 that are slightly more relaxed than the criteria in Directory#12 and these more stringent attributes of the NPCC criteria were not incorporated into the regional standard.

Specifically, the NPCC criteria in Directory#12 (Sections 5.1.1 and 5.1.2) state that (1) frequency decline is arrested at no less than 58.0 Hz for the portions of NPCC in the Eastern Interconnection, and 56.0 Hz for the portion of NPCC in the Quebec Interconnection (2) frequency should not remain below 59.5Hz for more than 30 seconds and should not remain below 58.5 Hz. for more than 10 seconds. Review the need to include the performance criteria presently in Directory#12 into PRC-006-NPCC-02, or whether the performance criteria included in PRC-006-1/PRC-006-2 is sufficient.

Interpretations of PRC-006-NPCC-1 to be considered to clarify PRC-006-NPCC-2.

The review will include an assessment of the need to include language to address dispersed generation resources.

PRC-006-NPCC-2 should be made to conform to the NERC Results Based Standard format.

After this review is completed, it will be determined if PRC-006-NPCC-1 should be revised, or retired.

Reliability Functions

The Standard will Apply to the Following Functions (Check all applicable boxes.)

☐	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
☐	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Coordinator	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
☐	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
☒	Transmission Owner	The entity that owns and maintains transmission facilities.
☐	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
☐	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
☐	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
☐	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☒	Generator Owner	Entity that owns and maintains generating units.
☐	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
☒	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer.

☐	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check all boxes that apply.)*	
☒	1. Interconnected bulk 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.
Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*	
Recognizing that reliability is an Common Attribute of a robust North American economy:	
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

Review and compare regional standard PRC-006-NPCC-1with continent-wide standards PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 to determine if revisions are necessary, or retirement of PRC-006-NPCC-01 possible.

Determine the necessity for including wording to address dispersed generation resources.

Consider incorporating more stringent aspects of Directory#12 in order to facilitate future retirement of Directory#12.

Related Standards

Standard No.	Explanation
PRC-006-1/PRC-006-2	NERC Automatic Underfrequency Load shedding
PRC-024-1/PRC-024-2	NERC Generator Frequency and Voltage Protective Relay Settings

Related SARs or RSARs

SAR ID	Explanation

Information in a Regional Standard Authorization Request (RSAR)

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

Regional Standard Authorization Request Form

Title of Proposed Standard:	PRC-006-3--Automatic Underfrequency Load Shedding – Variance for the Quebec Interconnection
Request Date:	June 2, 2015

RSAR Requester Information

Name:	Patrick Doyle Lee Pedowicz	**RSAR Type (Check box for one of these selections.)**	
Company:	Hydro-Québec TransÉnergie Northeast Power Coordinating Council, Inc. (NPCC)	☐	New Standard
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Fax:	1-212-302-2782	☐	Withdrawal of Existing Standard
Email:	doyle.patrick@hydro.qc.ca lpedowicz@npcc.org	☐	Urgent Action

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

The purpose of this RSAR is to address the two problems mentioned below by modifying only those sections that are specific to the Quebec Interconnection (PRC-006-2 Section D. Regional Variances, Part D.A. Regional Variance for the Quebec Interconnection, and Attachment 1A (Quebec)). Revisions to the standard will ensure the continuity of System reliability in the Quebec Interconnection.

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

The industry need for this RSAR is to address two specific problems regarding UFLS requirements for the Quebec Interconnection :

1 - To meet the PRC-006-2 59.3 Hz requirement for scenarios where Quebec has a small generation deficiency (between 4 and 6 percent) those scenarios would require modifications to the current settings of the UFLS program to the threshold of 59.3 Hz which would cause unacceptable and frequent load shedding without any improvement to System reliability.

2 – Because the Quebec Interconnection itself is an island with unique generation characteristics and SPS applications, Section D.A.3 in PRC-006-2 needs to be revised to define a more accurate generation deficiency scenario applicable to the Quebec Interconnection.

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

A description of the two specific problems is as follows:

1 - The Quebec Interconnection has a low inertia compared to other Interconnections. This makes it subject to large frequency deviations during normal operation. Small generation deficiencies (4 to 6 percent) can lead to acceptable frequency deviations without triggering any UFLS thresholds, but still stabilize under a PRC-006-2 Attachment 1A performance curve. The scope of this SAR is to modify the performance curve in Attachment 1A to better reflect the design, performance, and modeling of the Quebec Interconnection and avoid unnecessary load shedding.

2 - The Quebec Interconnection is an island by itself and is the only island considered when performing the Quebec UFLS program assessment. No under-generated island can be created within the Quebec Interconnection. Under current planning and operational criteria, the largest generation deficiency scenarios are limited to the loss of the largest power plant not covered by a SPS. Using the peak case scenario, these generation deficiencies are far from the required 25%. Section D.A.3 should be revised to account for the characteristics of the Quebec Interconnection.

Reliability Functions

The Standard will Apply to the Following Functions (Check all applicable boxes.)		
☐	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
☐	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Coordinator	The responsible entity that assesses the longer-term reliability of its Planning Coordinator Area.
☐	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
☒	Transmission Owner	The entity that owns and maintains transmission facilities.
☐	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
☐	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
☐	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
☐	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☐	Generator Owner	Entity that owns and maintains generating units.
☐	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.

☒	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer.
☐	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check all boxes that apply.)*	
☒	1. Interconnected bulk 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.
Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*	
Recognizing that reliability is an Common Attribute of a robust North American economy:	
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

1 - Because of the characteristics of the Quebec Interconnection, 0.5-1.5 Hz frequency deviations resulting from small losses of generation occur frequently. The System is designed and operated such that these small generation losses are acceptable, do not pose any threat to System reliability, and do not lead to unnecessary automatic load shedding. The adjustment of the UFLS anti-stall threshold to meet the PRC-006-2 performance curve would cause frequent and unacceptable load shedding operations without any improvement to System reliability. This is clearly shown by recent UFLS program assessment studies, planning and operational studies, and the analysis of generation loss scenarios in the Quebec Interconnection.

During the 2014 assessment of the NPCC Underfrequency Load Shedding Program, studies showed that for small generation deficiencies (between 4 and 6 percent) in the Quebec Interconnection using the minimum spinning reserve requirement, the simulated frequency deviation does not meet the PRC-006-2 requirement of 59.3 Hz from Attachment 1A. However, further investigation determined that such scenarios result in acceptable frequency deviations without crossing any UFLS thresholds while stabilizing between the PRC-006-2 curve (59.3 Hz in Attachment 1A) and the upper UFLS (anti-stall) threshold (59.0 Hz) that is defined in PRC-006-NPCC-1 UFLS Table 4 - Quebec Interconnection. Meeting the PRC-006-2 59.3 Hz requirement for those scenarios would require modifications to the current settings of the UFLS program. The subsequent adjustment of the UFLS anti-stall threshold to 59.3 Hz would cause unacceptable and frequent load shedding without any gain to System reliability.

2 - The Quebec Interconnection is an island by itself and it is the only island considered when performing the Quebec UFLS program assessment. Due to the nature of the Quebec System's design (main generation centers located in the north, remote from the main load centers in the south), no other viable island with generating deficiencies can be created within the Quebec Interconnection. Under current planning and operational criteria, the largest generation deficiency scenarios are limited to the loss of the largest power plant not covered by a SPS. Assuming the Hydro-Quebec peak case scenarios, none of them would result in a 25% generation deficiency. To reach the 25 % criteria using a design (normal or extreme) contingency and viable island, a light load scenario was used while studying the loss of the largest power plant. This methodology is currently used in Hydro-Quebec and has been used since the JWG-2 Phase II (NPCC Joint Working Group for the review of adequacy of procedures for protection against off-nominal frequency operation) Report was published in 1993. However, further studies and investigations have shown that using the peak case scenario, the integrity of the Quebec Interconnection could not be preserved using a UFLS program for a 25% generation deficiency. Since there is no design contingency that can produce a generation deficiency of 25%, multiple extreme contingencies, such as the loss of more than one substation, need to be applied simultaneously on the peak case scenario in order to reach that level of generation deficiency. Using the peak load case scenario, these generation deficiencies do not meet the required 25%. Section D.A.3 should be revised to reflect the characteristics of

the Quebec Interconnection.

Related Standards

Standard No.	Explanation

Related SARs or RSARs

SAR ID	Explanation

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)**	**Docket No. RM16-7-000**

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

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)** **)** **)**	**Docket No. RM16-7-000**

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

The North American Electric Reliability Corporation ("NERC") hereby provides comments on the Federal Energy Regulatory Commission ("Commission") Notice of Proposed Rulemaking ("NOPR") proposing to approve Reliability Standard BAL-002-2.[1] As the Commission stated in the NOPR, proposed Reliability Standard BAL-002-2 is just and reasonable, as it improves upon currently effective Reliability Standard BAL-002-1 and "satisfies the Order No. 693 directive that NERC develop a continent-wide contingency reserve policy."[2]

In proposing to approve Reliability Standard BAL-002-2, the Commission also proposes to direct NERC to do the following:

1. modify proposed BAL-002-2 to require entities to recover Reporting ACE within the 15-minute Contingency Event Recovery Period unless the Reliability Coordinator ("RC") expressly authorizes an extension;

2. modify proposed BAL-002-2 to eliminate the potential for unlimited resets of the 90-minute Contingency Reserve Restoration Period and to ensure that entities restore Contingency Reserve within the Contingency Reserve Restoration Period;

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[1] *Notice of Proposed Rulemaking, Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard,* 155 FERC ¶ 61,180, 81 Fed. Reg. 33441 (2016) ("NOPR").

[2] *Id.* at P 18.

3. develop a new or revised Reliability Standard to address events that cause a megawatt ("MW") loss greater than the Most Severe Single Contingency ("MSSC"); and

4. revise the Violation Risk Factors ("VRF") for Requirements R1 and R2 of proposed BAL-002-2 from "Medium" to "High."[3]

In addition, the Commission seeks comment on whether the proposed NERC Glossary definition of Contingency Reserve should include the NERC-defined term "Demand-Side Management."[4]

I. EXECUTIVE SUMMARY

As discussed below, NERC supports the Commission's proposal to approve proposed Reliability Standard BAL-002-2. NERC also provides the following comments to the issues raised in the NOPR:

Recovery of Reporting ACE within the Contingency Event Recovery Period – The Commission's proposal to require the RC to authorize any extension of the 15-minute Contingency Event Recovery Period is unnecessary. First, extensions of the Contingency Event Recovery Period would not allow responsible entities to "lean on the system" to the detriment of BES reliability. Reliability Standard BAL-001-2 helps ensure that Balancing Authorities ("BAs") do not lean on the system, as it requires BAs to ensure that their clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit ("BAAL"), which is an Interconnection-wide measure of frequency, for more than 30 minutes. Second, the RC is already responsible for monitoring system conditions and has the authority to direct the actions of BAs to maintain reliability. Pursuant to EOP-011-1, BAs and RCs must coordinate to restore the system to normal operating conditions if a responsible entity experiences conditions

[3] *Id*. at PP 19-20.

[4] *Id.* at 18.

rising to the level of an Emergency. Further, the RC must constantly monitor reliability in its area under Reliability Standards EOP-003-2, IRO-001-4, IRO-002-4, IRO-008-2, and IRO-009-2, and it is required to direct other functional entities to take action necessary to maintain reliability in its area, including actions with respect to Reporting ACE. The RC should be focused on maintaining reliability under these standards instead of approving each extension to the 15-minute Contingency Event Recovery Period.

Restoration of Contingency Reserve within the Contingency Reserve Restoration Period– The Commission's concern with the potential for unlimited resets of the 90-minute Contingency Reserve Restoration Period is misplaced. Pursuant to Requirement R3, after a Reportable Balancing Contingency Event, a responsible entity must begin recovery of Contingency Reserve to restore the Contingency Reserve to at least its MSSC before the end of the 90-minute Contingency Reserve Restoration Period. If an intervening Balancing Contingency Event occurs during the Contingency Reserve Restoration Period, however, entities are granted an extension to recover from the successive loss (i.e., the 90-minute period is "reset"). The potential for unlimited resets is negligible given resource limitations and the requirements of Reliability Standard BAL-001-2. In conjunction with BAL-001-2, Requirement R3 of BAL-002-2 appropriately incentivizes entities to recover resources after a Reportable Balancing Contingency Event until the entity fully restores Contingency Reserve to appropriate levels without the potential confusion that a "credit" system could introduce.

Events Causing MW Loss above the Most Severe Single Contingency ("MSSC") – NERC supports the Commission's attention to events that cause MW loss above an entity's MSSC. After a contingency event, it is critical for grid reliability that responsible entities restore system frequency, ensure that transmission lines are not overloaded, and manage resources

without undue impact to the interconnected Bulk Electric System ("BES"). The Commission's concern with respect to events resulting in a MW loss greater than an entity's MSSC is misplaced. While proposed Reliability Standard BAL-002-2 focuses on events with a loss less than or equal to the MSSC, it was designed in coordination with several Commission approved Reliability Standards that address, among other things, reliability issues stemming from an event resulting in MW loss greater than the MSSC. When contingency events cause loss greater than an entity's MSSC, Reliability Standards BAL-001-2, BAL-003-1, EOP-002-3, EOP-011-1, IRO-001-4, TOP-001-3, IRO-008-2, and IRO-009-2 require entities to take action to maintain reliability in Real-time, and thus, no reliability gap exists.

VRFs for Requirements R1 and R2 – Requirements R1 and R2 of proposed Reliability Standard BAL-002-2 support an entity's responsibility to balance resources with demand. As explained below, the performance obligations under Requirements R1 and R2 are consistent with a "Medium" VRF in Commission-approved VRF guidelines, as failure to meet the performance obligation set forth in these Requirements in "real time" are "unlikely to lead to BES instability, separation, or cascading failures."[5]

Reference to "Demand-side Management" in the Definition of Contingency Reserve – Consistent with a Commission directive in Order No. 693,[6] NERC developed the proposed definition of Contingency Reserve to enable entities to use technically appropriate Demand-Side Management resources as Contingency Reserve. The NERC Glossary defines the term "Demand-side Management" broadly, however, as it refers to all programs or initiatives

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[5] *See Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard BAL-002-2*, Docket No. RM16-7-000 (filed Jan. 29, 2016), Ex. G (Violation Risk Factors and Violation Severity Levels) at 113 ("Petition").

[6] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 330, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

implemented to reduce demand, some of which may not be appropriate for use as Contingency Reserve (e.g., energy efficiency). As proposed, the definition of the term "Contingency Reserve" appropriately characterizes demand side resources as comparable to conventional generation while only allowing entities to include resources that are "technically capable" of providing Contingency Reserve.[7]

II. BACKGROUND

On January 29, 2016, NERC filed a petition for approval of proposed Reliability Standard BAL-002-2, eight new or revised NERC Glossary definitions, and the associated VRFs and violation severity levels ("VSL") and implementation plan ("Petition").[8] NERC developed proposed Reliability Standard BAL-002-2 to address outstanding directives from Order No. 693 regarding the use of demand side management as a resource for contingency reserve and the development of a continent-wide contingency reserve policy. As stated in the Petition, proposed Reliability Standard BAL-002-2 improves upon currently effective Reliability Standard BAL-002-1 because it "clarifies obligations associated with achieving the objective of BAL-002 by streamlining and organizing the responsibilities required therein, enhancing the obligation to maintain reserve, and further defining events that predicate action under the standard."[9] NERC also stated that the proposed standard and associated NERC Glossary terms were designed to address outstanding Commission directives to create a continent-wide Contingency Reserve standard and to allow demand side management resources to be included as contingency reserve when necessary.[10]

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7 *See id*. at P 334.

8 *Petition* at 1.

9 *Id*. at 13.

10 *Id*. at 14, 33.

On February 12, 2016, NERC supplemented its Petition to clarify how transmission line loading issues will be addressed after the retirement of Reliability Standard TOP-007-0.[11] NERC submitted additional supplemental information on March 31, 2016, to "further clarify the extent to which BAL-002-2 interacts with other Commission-approved Reliability Standards to promote Bulk Power System reliability…[and support] the overarching policy objective reflected in the stated purpose of Reliability Standard BAL-002-2."[12]

On May 19, 2016, the Commission issued the NOPR, proposing to approve proposed Reliability Standard BAL-002-2 and find that it is just and reasonable, improves upon the current Commission-approved Reliability Standard BAL-002-1, and addresses outstanding Commission directives from Order No. 693.[13] Additionally, the Commission proposed to direct NERC to address issues regarding (1) the 15-minute ACE recovery period; (2) the 90-minute Contingency Reserve Restoration Period; (3) the applicability of BAL-002-2 to events causing MW loss above the MSSC; and (4) the VRFs for Requirements R1 and R2. The Commission also requested comments on whether the NERC Glossary definition of Contingency Reserve should reference the Commission-approved NERC Glossary term "Demand-side Management."[14]

III. COMMENTS

NERC supports the Commission's proposal to approve proposed Reliability Standard BAL-002-2, eight related new and revised NERC Glossary definitions, and the associated

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[11] *Clarifying Supplemental Information for Petition for Approval of BAL-002-2*, Docket No. RM16-7-000 (filed Feb. 12, 2016).

[12] *Supplemental Information for Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard BAL-002-2*, Docket No. RM16-7-000 (filed Mar. 31, 2016) ("Supplemental Information") at 1, 5.

[13] *NOPR* at PP 16, 18.

[14] *Id*. at P 18.

implementation plan and VRFs and VSLs. NERC agrees with the Commission that proposed BAL-002-2 "satisfies the Order No. 693 directive that NERC develop a continent-wide contingency reserve policy,"[15] and that the standard "clarifies the obligations imposed on responsible entities and is therefore an improvement on currently-effective Reliability Standard BAL-002-1."[16] NERC also agrees with the Commission that proposed BAL-002-2 represents an improvement upon currently-effective Reliability Standard BAL-002-1 by "consolidating the number of requirements to streamline and clarify the obligations related to achieving [the] goals" of balancing resource and demand and restoring ACE and Contingency Reserve.[17] With respect to the Commission's requests for comments and proposed directives, NERC provides the following comments.

A. 15-minute Contingency Event Recovery Period

1. NOPR

The Commission proposes to expand Reliability Standard BAL-002-2 by removing the automatic extension of the 15-minute Contingency Event Recovery Period in Requirement R1, Part 1.3,[18] and by requiring BAs to obtain approval from the relevant RC for any extension of the

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15 *Id.*

16 *Id*. at P 22.

17 *Id*. at P 18.

18 Under Part 1.3, a responsible entity may extend the 15-minute period under two circumstances:

(1) The responsible entity may extend the period if it (a) is a BA experiencing a RC-declared Energy Emergency Alert Level or is a Reserve Sharing Group whose member, or members, are experiencing a RC-declared Energy Emergency Alert level, (b) is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and (c) has depleted its Contingency Reserve to a level below its Most Severe Single Contingency.

(2) A responsible entity may extend the period if it experiences (1) multiple Contingencies where the combined megawatt loss exceeds its MSSC and that are defined as a single Balancing Contingency Event, or multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the responsible entity's MSSC.

Contingency Event Recovery Period. The Commission states that it is concerned with the Part 1.3 extension because there is the possibility that a BA operating "out-of-balance" for an extended period will "lean" on the system during the extension of the 15-minute period by relying on external resources to meet its obligations.[19] The Commission states that this "leaning" could affect other entities within an Interconnection, "particularly if another entity is reacting to a grid event while unaware that the first entity has not restored its ACE."[20] Citing to the RC's wide-area view, the Commission believes that the RC is the appropriate responsible entity to decide whether the BA should be able to extend the Contingency Event Recovery Period. Accordingly, the Commission proposes to direct NERC to "develop modifications to Reliability Standard BAL-002-2 that would require Reporting ACE recovery within the 15-minute Contingency Event Recovery Period unless the relevant reliability coordinator expressly authorizes an extension of the 15-minute ACE recovery period after the balancing authority has met the criteria described in Requirement R1, Part 1.3.1."[21]

2. Comments

NERC agrees with the Commission that, given its wide area view of reliable operations, RC oversight of extensions of the Contingency Event Recovery Period is important for maintaining reliability. Nevertheless, the Commission's proposed directive is unnecessary for two reasons, as set forth below. First, extension of the Contingency Event Recovery Period would not allow responsible entities to "lean on the system" to the detriment of BES reliability, because Reliability Standard BAL-001-2 requires a BA to ensure that its clock-minute average of Reporting ACE does not exceed its clock-minute BAAL for more than 30 minutes. Second, the

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19 *NOPR* at P 22.

20 *Id*.

21 *Id*. at P 24.

RC is already responsible for monitoring system conditions on an ongoing basis pursuant to Reliability Standards EOP-011-1, EOP-003-2, IRO-001-4, IRO-002-4, IRO-008-2, and IRO-009-2. Accordingly, as described in more detail below, requiring the RC to approve extension of the Contingency Event Recovery Period is unnecessary and is not a results-based requirement.

a) *Extension of the 15-minute Contingency Event Recovery Period will not allow responsible entities to "lean on the system" to the detriment of reliability.*

As noted, Requirement R1, Parts 1.3.1 and 1.3.2 of proposed BAL-002-2 exempt responsible entities from Reporting ACE restoration within the Contingency Event Recovery Period if the entity (i) is in a RC-declared Energy Emergency Alert Level, or (ii) experiences subsequent contingencies that exceed the MSSC, respectively. As explained in the Petition, if the responsible entity is in an RC-declared Energy Emergency Alert Level, the entity would need additional time to recover Reporting ACE due to the critical loss of resources that caused the Emergency. Similarly, if the entity experiences contingencies that cause loss above the MSSC, the entity would need an extended Contingency Event Recovery Period to recover the capacity lost beyond the MSSC. When responsible entities are in an RC-declared emergency or experience subsequent contingencies exceeding the MSSC, however, an extension of the 15-minute Contingency Event Recovery Period would not encourage entities to "lean" on the system by relying on external sources. That is because entities are required to meet resource obligations pursuant to Reliability Standard BAL-001-2. Specifically, an entity that operates out-of-balance for an extended period and that depends on the resources of its neighbors would be unable to maintain its Reporting ACE to predefined levels within 30 minutes, thus violating Commission-approved Reliability Standard BAL-001-2.

Reliability Standard BAL-001-2 requires each BA to (i) meet the Control Performance Standard 1 ("CPS1"), which is a long-term measure of frequency control performance, and (ii)

control its clock-minute average of Reporting ACE so that it does not exceed its clock-minute BAAL for more than 30 minutes. Compliance with CPS1 ensures that each BA maintains its share of responsibility for control of steady-state interconnection frequency and prevents responsible entities from devolving its responsibility for the Interconnection frequency on its neighbors. The BAAL, which is a short-term measure of frequency performance, is a unique limit on a BA's Reporting ACE based on Real-time interconnection frequency levels. Maintenance of Reporting ACE within the BAAL ensures that BAs are collectively maintaining Interconnection frequency on a pro rata basis. Taken together, compliance with CPS1 and maintenance of Reporting ACE within the BAAL ensure that entities are not permitted to "lean" on the system such that it presents an unreasonable risk of causing a reliability event because each responsible entity must contribute its fair share of resources towards Interconnection frequency in the short and long term.

For example, a BA experiencing a Contingency Event would face a contemporaneous Reporting ACE reduction equal to the amount of resource lost in the event. This additional resource loss and associated Reporting ACE reduction would cause the BA to be further from the bounds of the BAAL, described above. The BA would have to respond within 30 minutes with additional resources or load shedding to bring its Reporting ACE back within the BAAL. In addition, since the loss of a resource would influence the Interconnection's frequency, the BAAL would adjust (or "tighten") to assure that the Interconnection frequency remains in a safe range. The BA must return its operations to within the "tightened" BAAL within 30 minutes and thus would not be able to "lean" on the Interconnection for any prolonged period.

In short, after a Reportable Balancing Contingency Event that affects Interconnection frequency, the BAAL would tighten, and all entities with a negative Reporting ACE would be

required to provide resources to account for this frequency deficit. The entity that lost the resource that caused the frequency decline would also be required to utilize resources to return the Reporting ACE to acceptable limits. If the entity fails to respond to the loss of significant resources within this 30-minute period, the entity would violate Requirement R2 of BAL-001-2. Additionally, if entities experience a significant event that causes added tightening of the BAAL, all entities are incentivized to restore conditions within the limits set by BAL-001-2 as quickly as feasible in order to be prepared for any additional loss.

b) *RC approval of extensions to the 15-minute Contingency Event Recovery Period is unnecessary because affected RCs are already required to maintain constant oversight of conditions within their areas.*

Pursuant to Reliability Standards EOP-011-1, EOP-003-2, IRO-001-4, IRO-002-4, IRO-008-2, and IRO-009-2, the RC must maintain constant oversight of reliability within its RC area and must direct other responsible entities to take any actions necessary to maintain reliability.[22] As the RC should be focused on maintaining reliability under these standards, additional RC involvement through approval of an extension to the 15-minute Contingency Event Recovery Period is unnecessary.

First, if a responsible entity experiences a Balancing Contingency Event that rises to the level of an Emergency according to Reliability Standard EOP-011-1 (or if an entity experiences a Reportable Balancing Contingency Event and subsequent events which lead to an Emergency), the RC will declare an Energy Emergency Alert, monitor recovery of the Emergency, and issue Operating Instructions to responsible entities, as necessary. Under EOP-011-1, the TOP or BA

[22] NERC notes the relationship among these standards and TOP-001-3. The purpose of TOP-001-3 is "[t]o prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences." While the standard does not obligate the RC to take any action in furtherance of this purpose, the standard requires other entities to take action or direct action necessary to maintain reliability that may have originated as an RC directive.

must develop an Operating Plan that sets forth processes requiring responsible entities (including the RC) to, among other things, manage resources and control transmission line loading issues. Requirement R3 of EOP-011-1 requires the RC to review the Operating Plan and notify the BA and TOP of any deficiencies, and Requirement R4 requires the TOP and BA to address these deficiencies and resubmit the Operating Plan to the RC.[23] Once the RC has declared an Emergency, responsible entities (including the RC) must act pursuant to an Emergency Operating Plan or Operating Instructions issued by the RC to mitigate the Emergency. Meanwhile, pursuant to Requirement R1, Part 1.3.1 of proposed BAL-002-2, if the RC has declared an Emergency, the 15-minute Contingency Event Recovery Period would reset to allow additional time necessary for recovery from the event. Thus, the RC should be focused on maintaining reliability and restoring operating conditions according to the Operating Plan after an Emergency, and not whether to formally approve an extension of the 15-minute Contingency Event Recovery Period.

Second, even in non-emergency circumstances not addressed by EOP-011-1, the RC would be involved in recovery from Balancing Contingency Events, as the RC is required to act or direct others to act to mitigate reliability issues in Real-time pursuant to IRO-001-4 and other related standards, including EOP-003-2, IRO-002-4, IRO-008-2, or IRO-009-2.[24] Losses that are greater than the MSSC put the responsible entity in the difficult position of restoring resources to

[23] NERC notes that even though Reliability Standard EOP-011-1 does not explicitly require the RC to approve the Operating Plan after the responsible entity implements revisions based on RC direction, the responsible entity must revise the Operating Plan according to the RC directive or the responsible entity will violate Requirement R4 of EOP-011-1.

[24] As explained on page 9 of the *Supplemental Information*, Reliability Standards TOP-001-3, EOP-003-2, IRO-008-2, and IRO-009-2, collectively, require the RC to coordinate with TOPs and BAs to monitor SOL and IROL in real time and direct mitigation of those exceedances. Additionally, under Reliability Standard IRO-001-4, the RC has the responsibility to issue Operating Instructions to address the reliability within its RC area, and under Reliability Standard IRO-002-4, the RC must enable relevant System Operators to perform monitoring and analysis and to take action to control reliability based on its analyses.

maintain Reporting ACE within the Contingency Event Recovery Period, often an unrealistic requirement if losses are above the MSSC. In these instances, the responsible entity would need an extension of the 15-minute Contingency Event Recovery Period under Requirement R1, Part 1.3.2 to recover losses, which have been compounded because of the second event, while still maintaining service to loads. Additional involvement by the RC beyond oversight of operations required under the abovementioned Reliability Standards is not necessary at this stage because the entity is recovering from the multiple losses but is not subject to immediate reliability complications. As noted above, the RC should be focused on its monitoring and oversight responsibilities instead of approval of an extension to the Contingency Event Recovery Period.

For the foregoing reasons, requiring the RC to approve extensions of the Contingency Event Recovery Period under Requirement R1, Parts 1.3.1 and 1.3.2 is redundant and unnecessary, and during events causing loss greater than the MSSC, the RC should be focused on more pressing reliability concerns, such as transmission loading and frequency management.

B. 90-minute Contingency Reserve Restoration Period

1. NOPR

Under Requirement R3 of proposed BAL-002-2, a responsible entity experiencing a Reportable Balancing Contingency Event is required to restore its Contingency Reserve within the 90-minute Contingency Reserve Restoration Period unless the entity experiences an additional Balancing Contingency Event within that timeframe. If the entity experiences an intervening Balancing Contingency Event during the Contingency Reserve Restoration Period, the period is "reset" to allow additional time for recovery from the compounded loss. While the Commission agrees that it may be difficult for entities to fully recover Contingency Reserve within the 90-minute Contingency Reserve Restoration Period if, for example, there is "a Balancing Contingency Event involving substantial megawatt loss that occurs during the

recovery period following a Reportable Balancing Contingency Event…," the Commission is concerned that Requirement R3 would provide entities continuous resets of the Contingency Reserve Restoration Period such that Contingency Reserve are not returned to the appropriate level on a timely basis.[25]

Accordingly, the Commission proposes to direct NERC to "develop modifications to Reliability Standard BAL-002-2 to eliminate the potential for unlimited resets and ensure that Contingency Reserve must be restored within the 90-minute Contingency Reserve Restoration Period."[26] In proposing to direct this revision, the Commission states that a possible approach is to give the responsible entity "credits'" for MW loss "resulting from Balancing Contingency Events during the 90-minute Contingency Reserve Restoration Period and allow an additional 90 minutes to restore reserves associated with those megawatt losses, if necessary."[27]

2. Comments

NERC appreciates the Commission's attention to recovery of Contingency Reserve following a Reportable Balancing Contingency Event. Given the inherent relationship between preparedness for unplanned contingency events and frequency management, NERC agrees that entities must maintain a requisite level of Contingency Reserve as a preparatory measure for future contingency events. NERC also agrees with the Commission that a MW loss occurring "during the recovery period following a Reportable Balancing Contingency Event may make it infeasible to fully restore the contingency reserve as originally planned."[28]

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25 *NOPR* at P 27.

26 *Id*. at P 29.

27 *Id*.

28 *Id*. at P 27.

The Commission, however, should not be concerned about the potential for "unlimited resets" of the 90-minute Contingency Reserve Restoration Period. As described below, if an intervening Balancing Contingency Event occurs during the Contingency Reserve Restoration Period, entities would need an extension to recover from the successive losses. Additionally, the automatic Contingency Reserve Restoration Period "reset" in Requirement R3 is just and reasonable because (i) entities would not be able to experience "unlimited resets" of the 90-minute Contingency Reserve Restoration Period given resource limitations and requirements in BAL-001-2, and (ii) Requirement R3 would eliminate confusion and ensure that entities eventually fully restore the Contingency Reserve to respond to the next loss up to the MSSC. NERC provides additional detail supporting each of the reasons described above in the proceeding discussion.

a) *Entities need additional time to recover Contingency Reserve after intervening Balancing Contingency Events.*

Entities that have experienced a Reportable Balancing Contingency Event need additional time to recover Contingency Reserve after the occurrence of an intervening Balancing Contingency Event (i.e., another event that occurs during the Contingency Reserve Restoration Period) to recover the additional lost resources. Because recovery during the original 90 minutes would be much more difficult, if not infeasible, after an additional event, an extension of the 90 minutes would encourage entities to recover lost resources to meet the performance requirement of Requirement R3.

If a responsible entity experiences a Reportable Balancing Contingency Event and an additional Balancing Contingency Event within the Contingency Reserve Restoration Period, the entity would be subject to compounded reductions in resources beyond the original loss, which would exacerbate the Contingency Reserve MW deficit and make full recovery much more

difficult. As stated in the Petition and reiterated by the Commission, this additional loss may make recovery "infeasible" within a set period.[29] For example, an entity may lose resources in an initial event, and while the entity is recovering from the first event, the entity experiences a second event that affects the entity's recovery of resources from the original loss.[30] After the "reset" under Requirement R3, the responsible entity would have a renewed 90-minute period to recover from both the original event and the second event. Thus, even if an intervening event is smaller in size or scope and does not rise to the level of a Reportable Balancing Contingency Event, the responsible entity's on-hand resources would be depleted further, and the entity would need to recover both the original loss and the subsequent loss of resources.

By allowing an extension of the 90-minute Contingency Reserve Restoration Period upon a second event, Requirement R3 is a results-based Requirement because it focuses on required actions or results (continued, timely restoration of Contingency Reserves) and not necessarily the methods by which to accomplish those actions or results. Specifically, Requirement R3 requires a responsible entity to continue to restore each unit that is lost after a Reportable Balancing Contingency Event, regardless of successive losses. Future Balancing Contingency Events would not eliminate the requirement to actively restore lost reserve; rather, a Balancing Contingency Event after a Reportable Balancing Contingency Event would merely extend the Contingency Reserve Restoration Period to ensure that the responsible entity has adequate time to recover from consecutive losses. In this way, the "reset" function of the Contingency Reserve Restoration Period under Requirement R3 would provide an incentive for entities to continue active recovery of Contingency Reserve until restoration is complete instead of passively

[29] *Id*. at P 27; *see also Petition* at 27.

[30] For example, a 300 MW unit running at 200 MWs could be supplying 100 MWs of reserve. Therefore, the loss of 200 MW of generation creates a 300 MW reserve deficit.

expecting neighboring entities to supply needed resources once a violation has occurred. In other words, absent the "reset" of the Contingency Reserve Restoration Period under Requirement R3, a responsible entity that experiences successive losses and is unable to recover Contingency Reserve in the 90-minute period due to the additional loss of resources would be in violation of Requirement R3. However, if the entity receives additional time to account for these compounded losses, the entity would be incentivized to diligently restore its Contingency Reserve to avoid a violation of Requirement R3. This fact, combined with the requirement on entities to recover Contingency Reserve to the MSSC after Reportable Balancing Contingency Events and subsequent Balancing Contingency Events to meet BAAL and CPS1 requirements under BAL-001-2, ensures that entities continue to restore Contingency Reserve to recover from future events.

b) *Entities will not experience "unlimited resets" of the 90-minute Contingency Reserve Restoration Period.*

Because of the inherent limitation on an entity's resources, responsible entities would not be able to experience "unlimited resets" of the 90-minute Contingency Reserve Restoration Period under Requirement R3. Responsible entities have obligations to serve load and would be unable to do so if the entity is consistently losing units within the 90-minute Contingency Reserve Restoration Period. If an entity continues to trip units before full recovery of other units, the responsible entity would eventually fail to meet obligations under other Reliability Standards (including the requirement to recover ACE within 15 minutes under proposed BAL-002-2) and may eventually enter into an Emergency situation under RC oversight (i.e., the Contingency Reserve are depleted and Reporting ACE is affected).

Specifically, if the responsible entity continues to lose units without working to restore previously lost units (thus further depleting its Contingency Reserve), the responsible entity

would eventually run out of resources and would violate, among others, the Reporting ACE recovery requirements under currently effective BAL-001-2 and proposed BAL-002-2. Entities would not be able to return their Reporting ACE to within the BAAL in 30 minutes to meet BAL-001-2 if the entity has no Contingency Reserve resources to deploy to correct its ACE. Relatedly, entities would not be able to recover Reporting ACE within 15 minutes, which is the performance requirement under proposed Reliability Standard BAL-002-2, if the entity does not actively restore Contingency Reserve to deploy when necessary. Finally, if conditions continue to degrade, the responsible entity may enter into an Emergency under RC oversight under Reliability Standard EOP-011-1.

c) *Requirement R3 eliminates confusion and ensures that entities eventually fully restore the Contingency Reserve to the MSSC.*

Requirement R3 of proposed BAL-002-2 streamlines the process for restoration of Contingency Reserve, as it obligates responsible entities to restore Contingency Reserve to the MSSC upon the expiration of the 90-minute Contingency Reserve Restoration Period.

The Commission suggests that NERC implement a "credit" system that allows additional time for entities to engage in Contingency Reserve restoration based on the size and time of additional losses.[31] Under this proposed system, entities would be required to engage in a strict accounting of Contingency Reserve lost and recovered after the occurrence of a Reportable Balancing Contingency Event. Entities would be required to recover portions of its Contingency Reserve at different times, again depending on the size and time of additional losses after a Reportable Balancing Contingency Event. Implementation and enforcement of the proposed credit system would be confusing and burdensome, and it may attract attention away from full

[31] *NOPR* at PP 28, 29.

and final restoration of the Contingency Reserve. An initial draft of Reliability Standard BAL-002-2 required entities to take a similar approach to account for Contingency Reserve, but industry found this approach confusing, cumbersome, and difficult to implement.[32]

Proposed Requirement R3, as drafted, provides a clear method to track restoration of Reserve upon the occurrence of additional Balancing Contingency Events. The "reset" function under Requirement R3 is clear and effective and encourages entities to continue to restore Contingency Reserve to the MSSC after a Reportable Balancing Contingency Event.

C. Losses above the MSSC

1. NOPR

In the NOPR, the Commission expressed concern that, because BAL-002-2 does not address MW losses that exceed the MSSC, a reliability gap "may exist for megawatt exceedances of the most severe single contingency that do not cause energy emergencies or otherwise clearly implicate the other Reliability Standards cited by NERC."[33] The Commission states that if the coordinated suite of standards identified by NERC in its Petition and related Supplemental Information does not cover MW losses that exceed of the MSSC, BAs may "lean on the Interconnection by relying on external resources for an indeterminate period…"[34] Based on this perceived gap, the Commission requests comment on whether to expand obligations on responsible entities to restore Reporting ACE and recover Contingency Reserve to situations where an entity experiences losses greater than the MSSC. Depending on the comments, the

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[32] *Petition* at 188, 201, 595 (reflecting industry concern with Draft #1 of the proposed definition of Contingency Reserve Restoration Period, which was "A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, during which the amount of Contingency Reserve deployed to recover from a Balancing Contingency Event is to be restored.").

[33] *NOPR* at P 33.

[34] *Id*.

Commission may direct NERC to develop a new or modified Reliability Standard to address events that cause MW loss greater than the MSSC.[35]

2. Comments

As stated in NERC's Supplemental Information, NERC designed proposed Reliability Standard BAL-002-2 in coordination with several Commission approved Reliability Standards to address frequency, output loss, transmission loading, and to require reactive measures to prevent degradation of the system after a contingency event or series of events. Because these coordinated standards address important reliability issues and prohibit entities from being able to "lean" on the Interconnection when contingency events cause MW loss greater than an entity's MSSC (i.e., events that are not within the scope of Reliability Standard BAL-002-2), a new or modified Reliability Standard is not necessary for reliability.

Reliability Standards BAL-001-2, BAL-003-1, EOP-002-3, EOP-011-1, IRO-001-4, TOP-001-3, IRO-008-2, and IRO-009-2 require responsible entities to continuously maintain reliability in Real-time, as these standards require responsible entities to maintain frequency within limits, address transmission issues that may occur during recovery, recover from Emergencies, and fulfill reliability directives issued by the RC. Restoration of Contingency Reserve and recovery of Reporting ACE do not resolve imminent reliability issues that may occur when a responsible entity experiences a loss greater than the MSSC, such as transmission line loading issues or frequency deviations. To avoid unplanned outages and other major system issues, entities should consider these immediate components of reliability, addressed by the coordinated suite of standards mentioned above, as first priority after a large event causing MW loss above an MSSC. After the entity has recovered from the loss and secured reliable

[35] *NOPR* at 34.

operations, the entity should focus on restoration of Contingency Reserve and recovery of Reporting ACE pursuant to BAL-002-2.

An entity's MSSC, which is the largest single unit loss of resource output, is the appropriate threshold under which entities should be required to restore Contingency Reserve to predefined levels under BAL-002-2 because it requires entities to plan for this loss as part of normal daily operations. The requirement to restore Contingency Reserve supports the central performance requirement of BAL-002-2, to maintain Reporting ACE within predefined bounds, which is one of several important gauges that entities may use to monitor system frequency using a forward-looking accounting comparison of actual net interchange and scheduled net interchange.

For events causing loss greater than the MSSC, the abovementioned coordinated Reliability Standards require entities to control individual components of operations and are more appropriate to maintain reliability in Real-time. These standards, explained in more detail below, eliminate any perceived gap in reliability, as they address reliability issues when an event occurs that is greater than the MSSC, and they prohibit responsible entities from "leaning" on the Interconnection for an extended period of time or introducing reliability issues to the Interconnection while recovering from the large event.

i) BAL-001-2

Reliability Standard BAL-001-2 requires each BA to operate such that it meets the CPS1 and controls its clock-minute average of Reporting ACE so that it does not exceed its clock-minute BAAL for more than 30 minutes. In order to comply with BAL-001-2, entities must balance resources upon an event greater than an entity's MSSC because the BAAL tightens the acceptable limits for Reporting ACE, thus reducing frequency deviation and requiring the

responsible entity to restore its Reporting ACE to acceptable levels within 30 minutes. As described below, Reliability Standard BAL-001-2 employs a dual-pronged approach by combining both a short-term and long-term measure of frequency to ensure that entities support frequency on an incremental basis while maintaining reliability without causing undue burden on the system.

More specifically, Requirement R1 of Reliability Standard BAL-001-2 requires the BA to operate such that the BA meets the CPS1, which is a long-term measure of frequency control performance that uses statistical relationships between ACE and frequency to assign each BA a share of the responsibility for control of steady-state interconnection frequency, on an on-going basis. Requirement R2 of BAL-001-2 requires BAs to operate such that an entity's BAAL is not exceeded for a period of greater than 30 consecutive minutes, providing a short-term measure of frequency. The BAAL is a limit on Reporting ACE with respect to the prevailing frequency of the Interconnection in which the entity is located and promotes frequency control for losses including those greater than the MSSC. In sum, the BAAL in Requirement R2 strengthens the control on reliability created by CPS1 in Requirement R1 (given that CPS1 is a long-term measure of total risk over a 12-month period) to ensure frequency maintenance. The 30-minute time frame to restore Reporting ACE under BAL-001-2 is more appropriate for events with MW loss greater than the MSSC as it allows entities address unit losses while still maintaining reliability. Reliability Standard BAL-001-2 prevents entities from relying on external resources with no obligation to return conditions to pre-event conditions, because under this standard, an entity is always obligated to maintain Reporting ACE within the BAAL and to operate to CPS1 to comply.

The following example provides additional context for the coordination of BAL-002-2 with BAL-001-2 to avoid "leaning." In a hypothetical situation, an entity loses two large units within one minute, and the sum of the losses exceeds the MSSC by 500 MW. Assuming the entity was carrying an amount of reserve just equal to its MSSC, the entity will have a Reporting ACE of -500 MW at the end of the 15 minute Contingency Event Recovery Period. Because the loss exceeded the MSSC, the entity is not required to comply with BAL-002-2; however, the entity still must maintain its Reporting ACE within the BAAL within 30 minutes in order to comply with Requirement R2 of BAL-001-2. If each responsible entity operates within the BAAL, then the Interconnection will be able to restore its frequency to 60 Hz after an event. Because entities will ensure that its Reporting ACE meets BAL-001-2 to meet the requirements of the standard, and because other entities in the area may also experience large losses and further tighten the BAAL to meet the Requirements of the standard, each responsible entity continuously and expeditiously restore balance within its area or risk violating BAL-001-2.

ii) BAL-003-1

Reliability Standard BAL-003-1 requires entities to maintain Frequency Response resources to support Interconnection frequency when an event causes MW loss that may impact frequency. As BAL-003-1 obligates the responsible entity to deploy its proportional share of resources to accommodate events that would otherwise impact frequency until the frequency is restored to scheduled values, entities will control frequency without unnecessarily sacrificing reliability within its area and without "leaning" on other entities. Compliance with Reliability Standard BAL-003-1 is a more appropriate way to maintain frequency if an event with losses greater than the MSSC occurs because responsible entities are required to have Frequency

Response greater than the MSSC under the standard and can deploy these resources when these large events occur.

Entities must communicate with other entities in the Interconnection after an event that cause frequency deviations. After notifying other entities of the event and deploying its proportional share of Frequency Response resources, the responsible entity has the flexibility to focus on balancing its own resource and demand and maintain reliability within its area. Thus, BAL-003-1 ensures that responsible entities maintain proportional Frequency Response and must collectively deploy these resources, as necessary, to sustain Interconnection-wide frequency while avoiding unnecessary loss of load service. Reliability Standard BAL-003-1 requires entities to maintain more Frequency Response resources than any individual entity may maintain as Contingency Reserve under BAL-002-2. Because of this, and because BAL-003-1 will ensure that frequency remains stable during large events beyond the MSSC while entities are recovering Reporting ACE, BAL-003-1 is more appropriate to address events greater than the MSSC than Reliability Standard BAL-002-2.

In the example described above in Section C(2)(i), the entity experiencing multiple events in an Interconnection must respond to a dip in frequency caused by a large event to maintain frequency within the limits set by BAL-003-1. While BAL-001-2 requires all participants in the Interconnection to support frequency, the entity experiencing the loss must restore frequency pursuant to Reliability Standard BAL-003-1 and would thus not be able to "lean" on the Interconnection for its losses.

iii) TOP-001-3, EOP-003-2, IRO-001-4, IRO-008-2, and IRO-009-2

Taken together, Reliability Standards TOP-001-3, EOP-003-2, IRO-008-2, and IRO-009-2 require entities to address transmission issues at all times, including transmission issues that

may pose an immediate threat to reliability after an event causes loss greater than the MSSC.[36] Also, Reliability Standard IRO-001-4 requires the RC to take action, or direct others to take action, when there are reliability issues in the RC area.

First, Reliability Standard TOP-001-3 requires TOPs and BAs to operate within SOLs and IROLs and to mitigate, among other things, transmission line loading issues whether during Emergencies or normal operations. Second, Reliability Standard EOP-003-2 addresses Emergency transmission issues, such as voltage levels, uncontrolled failures or cascading outages, on an Interconnection basis by requiring BAs and TOPs to take action to respond to real-time emergencies rather than risk larger system failures. Finally, Reliability Standards IRO-001-4, IRO-008-2, and IRO-009-2 require the RC to monitor the reliability of the BES in its area (including transmission issues) and to direct relevant BAs or TOPs to take necessary measures to address issues in the RC area.

Given its wide-area perspective, the RC serves a critical role in the management of reliability across a wide area under Reliability Standards TOP-001-3, EOP-003-2, IRO-001-4, IRO-008-2, and IRO-009-2. These standards are important to maintaining real-time reliability upon the occurrence of a Balancing Contingency Event(s), as these standards address transmission issues while entities are restoring conditions and preparing resources to address successive losses. If a responsible entity experiences a Balancing Contingency Event that jeopardizes system conditions, the RC will be continuously overseeing conditions and must react under these standards to maintain reliability as necessary. By focusing on events across its entire area, the RC controls transmission issues that may arise while entities are returning Real-time

[36] For example, entities may experience transmission line loading issues (too many resources on transmission lines) when entities engage responsive resources to recover from a major event. When entities overload transmission lines, they may exceed the Interconnection Reliability Operating Limits ("IROL") and System Operating Limits ("SOL").

frequency, Reporting ACE, and Contingency Reserve to acceptable levels to comply with related Reliability Standards after recovery.

In the example described above in Section C(2)(i), the TOPs and the RCs would be continuously monitoring transmission line loading in the Interconnection where the loss occurred. If any transmission lines have flows above their rating, the TOPs and the appropriate RC would address the overloads. If no overloads occur, then the RC would not need to direct any corrective actions.

iv) EOP-011-1

Reliability Standard EOP-011-1 requires the RC, along with the responsible entity(ies) experiencing a major event or a serious of events that give rise to an RC-declared Emergency situation, to take proactive remedial measures to mitigate the Emergency. This standard addresses the most extreme of the events that cause loss greater than the MSSC, as it requires responsible entities to fully restore operating conditions after an Emergency event or after non-Emergency conditions have degraded into Emergency.

If the RC determines that an event or series of events that causes losses greater than an entity's MSSC is an Emergency, the responsible entity would act under its Emergency Operating Plan developed for compliance with Reliability Standard EOP-011-1.[37] The Operating Plan sets forth actions that entities must take to stabilize the system to alleviate the Emergency conditions. In an Emergency situation, the RC is in a unique position to determine whether imbalance is causing immediate reliability problems. If the RC has determined that the entity is in an

[37] As Commission-approved Reliability Standard EOP-011-1, which will go into effect on April 1, 2017, will cover obligations related to energy and capacity emergencies under Reliability Standard EOP-002-3, NERC's comments are specific to the relationship between Reliability Standard EOP-011-1 and proposed Reliability Standard BAL-002-2. *See Supplemental Information* at 11.

emergency, the entity may not be able to restore operating conditions without direction and assistance. The processes required under the EOP standards will prepare the responsible entity to ensure Reliable Operations in the event of a large contingency causing an Emergency situation. After the responsible entity has restored normal operations and the RC declares that the Emergency has ended, the entity will once again be required to comply with each of the above-mentioned standards.

In the context of the example described above in Section C(2)(i), if an event or series events occurs, frequency remains at or near 60 Hz, and transmission lines are not overloaded, then there are no immediate identified reliability risks to the Interconnection. If, however, the RC has declared an Emergency under EOP-011-1, the RC would work with the affected entity[ies] to mitigate reliability issues and return the system to normal operating conditions. Given this layer of RC involvement, responsible entities would not need to request additional RC permission to extend the recovery period.

D. Violation Risk Factors for Requirements R1 and R2

1. NOPR

The Commission proposes to increase the VRF associated with Requirements R1 and R2 by directing NERC to "assign a high violation risk factor to proposed Reliability Standard BAL-002-2, Requirements R1 and R2."[38] In doing so, the Commission expressed concern that NERC did not provide adequate justification for lowering the VRFs for Requirements R1 and R2 of proposed BAL-002-2, which are analogous to Requirements R3 and R3.1 of currently effective BAL-002-1, from "High" to "Medium."[39] The Commission also noted that when determining

[38] *NOPR* at P 38.

[39] *Id*. at P 37.

the VRF for a particular requirement, NERC should consider "the risk resulting from a failure to meet the performance set forth in the requirement in real time" regardless of the fact that the determination of degree of noncompliance is completed after occurrence of the event.[40] The Commission seeks comment on its proposal to direct NERC to revise the VRFs for Requirements R1 to R2 from "Medium" to "High."

2. Comments

The VRFs for Requirements R1 and R2 of proposed BAL-002-2 should not be changed from "Medium" to "High" because failure to perform these Requirements in real time would produce results consistent with the Commission approved guidelines for a "Medium" VRF.[41]

According to Commission-approved criteria for establishing NERC Reliability Standard VRFs, a VRF of "High" should be assigned to a Requirement that, if violated, could "directly cause or contribute to the 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[.]"[42] A VRF of "Medium" should be assigned to 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[,]" but that "is unlikely to lead to Bulk Electric System instability, separation, or cascading failures[.]"[43] Further, as mentioned above, the Commission stated in the NOPR that NERC must assign the VRFs based on "the risk resulting from a failure to meet the performance set forth in the requirement in real

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40 *Id*.

41 *See Petition* at 113; *see also NOPR* at P 37 (explaining that NERC must assign VRFs based on "the risk resulting from a failure to meet the performance set forth in the requirement in real time.").

42 *Id*.

43 *Id.*

time."[44] Requirements R1 and R2 of proposed Reliability Standard BAL-002-2 do not meet the criteria for a VRF of "High."

Requirement R1 requires responsible entities to recover Reporting ACE by deploying Contingency Reserve upon the occurrence of a Reportable Balancing Contingency Event. An entity's Reporting ACE is a measure of the "instantaneous difference between a balancing authority's Net Actual and Scheduled Interchange…" and represents an entity's obligation to support frequency. As such, the Reporting ACE is representative of an entity's elemental responsibility to balance resources with demand and stabilize frequency. While Reporting ACE is a valuable indicator of potential system conditions and may identify imbalance leading to unexpected power flows or frequency concerns, it is not indicative of an immediate vulnerability. In other words, a violation of Requirement R1, which establishes the requirement to return Reporting ACE to defined levels, is not an immediate measure of reliability, and the risk resulting from a failure to meet Requirement R1 in Real-time is "unlikely to lead to Bulk Electric System instability, separation, or cascading failures."[45]

The actions under proposed Requirement R2 support Requirement R1 by requiring responsible entities to develop, review, and maintain a process to determine the MSSC and to maintain, for deployment under Requirement R1, at least enough Contingency Reserve to cover the MSSC. As Requirement R2 ensures that a responsible entity calculates its unique Contingency Reserve threshold for restoration of Contingency Reserve, the requirement is critical to the implementation of proposed Reliability Standard BAL-002-2. Nevertheless, the risk from "failure to meet the performance set forth in the requirement in real time,"[46] does not

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44 *NOPR* at P 37.

45 *See Petition* at 113.

46 *NOPR* at P 37.

rise to the level of risk inherent in a requirement with a "High" VRF because the performance obligation under Requirement R2 does not directly contribute to reliability. Particularly, the requirement to develop, review, and maintain a process to calculate the MSSC is an accounting calculation used to determine how much Contingency Reserve is required. A violation of this Requirement in Real-time, outside of other factors, is "unlikely to lead to Bulk Electric System instability, separation, or cascading failures," and thus, a VRF of "Medium" is appropriate.

E. Revision to Definition of Contingency Reserve to Reference Demand-Side Management

1. NOPR

In its NOPR, the Commission notes that, while NERC proposed the revised NERC Glossary definition of Contingency Reserve to satisfy the Commission directive in Order No. 693 to include demand side management resources in Contingency Reserve calculations, the proposed definition does not include the term "Demand-side Management."[47] The Commission seeks comment on whether NERC should revise the proposed definition of Contingency Reserve to include the NERC Glossary term "Demand-side Management."

2. Comments

In developing the revised definition of Contingency Reserve, NERC intentionally omitted the NERC Glossary term "Demand-side Management" because the defined term is too broad to capture those resources that are appropriate for Contingency Reserve preparedness. The proposed definition balances the need for flexibility to include a variety of demand side resources in measurements of Contingency Reserve with the need to define the types of demand side resources that are "technically capable" to serve as contingency reserve.[48]

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47 *Id.* at P 18.

48 *See Order No. 693* at P 334.

The Commission-approved definition of Demand-Side Management is "[a]ll activities or programs undertaken by any applicable entity to achieve a reduction in Demand." NERC did not develop the term "Demand-Side Management" in the context of capacity that may be deployed as Contingency Reserve. Rather, the NERC Glossary definition for Demand-Side Management, which goes into effect on July 1, 2016, refers to all initiatives, programs, or activities that allow an entity to reduce Demand, regardless of the availability of these resources to respond at will. Under this definition, Demand-Side Management resources may include, for example, various programs to encourage consumers to employ technology that reduces demand on a long-term basis, such as energy efficiency. This definition of Demand-Side Management is not limited to time-sensitive, responsive supplies of energy that are technically capable of being deployed on an as needed basis as intended by NERC's proposed revision to the definition of Contingency Reserve.

In the Commission's Order No. 693, the Commission directed NERC to "explicitly allow[s] DSM as a resource for contingency reserves"[49] and clarified that demand side management resources "should be treated on a comparable basis and must meet similar technical requirements as other resources providing this service."[50] NERC developed the proposed definition of Contingency Reserve to fulfill this directive by allowing responsible entities to include demand side resources to respond to a Reportable Balancing Contingency Event. The proposed definition of Contingency Reserve is as follows:

> **Contingency Reserve:** The provision of capacity that *may be deployed* by the Balancing Authority *to respond to a Balancing Contingency Event* and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP

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49 *Order No. 693* at P 330.

50 *Id*. at P 335.

standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan. [emphasis added]

The proposed definition tailors the type of demand resources that may be used as Contingency Reserve to those that are "technically capable of providing Contingency Reserves,"[51] as it allows BAs to include "readiness to reduce Firm Demand" in its calculation of Contingency Reserve. In addition, the proposed definition provides responsible entities with the flexibility to use either conventional generation or demand side management as a resource for Contingency Reserve.[52]

NERC believes that the proposed definition represents an improvement to the currently effective definition of Contingency Reserve by providing adequate granularity regarding the type of resources that are technically appropriate to serve as Contingency Reserve while still maintaining the flexibility to employ new technology in the future. As explained above, the proposed definition fulfills the Commission directive from Order No. 693 to allow the use of demand side resources as Contingency Reserve while explicitly identifying resources that are appropriate for use as Contingency Reserve. With these revisions, proposed Reliability Standard BAL-002-2 is "clearer, provides users, owners and operators of the Bulk-Power System a set of

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[51] *Id*. at P 334.

[52] The proposed definition of Contingency Reserve allows responsible entities to include "readiness to reduce Firm Demand" in its calculation of Contingency Reserve but only if certain limits are met. Allowing entities to use "readiness to reduce Firm Demand" if certain limits are met is significantly different from using interruptible loads, interruptible Demand-Side Management programs, or Direct Control Load Management to meet normal Contingency Reserve needs.

options to meet contingency reserves, and treats DSM on a comparable basis with other resources."[53]

[53] *Order No. 693* at P 331.

IV. CONCLUSION

NERC supports the Commission's NOPR proposal to approve Reliability Standard BAL-002-2 and associated NERC Glossary definitions. For the reasons explained above, NERC requests that the Commission approve proposed Reliability Standard BAL-002-2 as submitted in the Petition as just, reasonable, and in the public interest.

Respectfully submitted,

/s/ Andrew C. Wills

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Counsel for the North American Electric Reliability Corporation

Date: July 25, 2016

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service lists compiled by the Secretary in Docket No. RM16-7-000.

Dated at Washington, D.C. this 25th day of July, 2016.

/s/ Andrew C. Wills

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

June 28, 2016

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

RE: Proposed Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events)
Docket No. RM15-11-000

Dear Ms. Bose:

On January 21, 2015, the North American Electric Reliability Corporation ("NERC") filed a petition for approval of proposed Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events). As described in detail in NERC's petition and subsequent filings in this proceeding, NERC's proposed Reliability Standard TPL-007-1 represents a state of the art approach to addressing the reliability risks posed by geomagnetic disturbances (or "GMDs") to the Bulk-Power System, a highly complex area in which industry and scientific understanding continues to evolve.

As noted in its April 28, 2016 filing, NERC recently identified the need for a minor revision to a figure in one of the technical white papers supporting the proposed Reliability Standard. Specifically, NERC identified an error in Figure 1 of the *Screening Criterion for Transformer Thermal Impact Assessment* white paper that resulted in incorrect plotting of simulated power transformer peak hot-spot heating from the Benchmark GMD Event.

Based on its analysis of the corrected Figure 1, the TPL-007-1 standard drafting team determined that the 75 A per phase threshold for transformer thermal impact assessment remains a valid criterion. Therefore, it is not necessary to revise any Requirements of the proposed Reliability Standard.

Nevertheless, to maintain a complete and accurate record, NERC revised the *Screening Criterion for Transformer Thermal Impact Assessment* white paper to incorporate the revised Figure 1. NERC also made corresponding revisions to related text, figures, and tables throughout the technical white papers supporting the proposed standard.

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The revisions, which were posted for stakeholder comment from May 12, 2016 through June 13, 2016, are summarized below:

- *Screening Criterion for Transformer Thermal Impact Assessment* white paper*:* (i) revisions to correct Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event; and (ii) corresponding revisions, including those to the related text and to Table 2: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event.

- *Benchmark Geomagnetic Disturbance Event Description* white paper: corresponding revision to Figure I-9: Calculated Peak Metallic Hot Spot Temperature for all possible circuit orientations and effective GIC.

- *Transformer Thermal Impact Assessment White Paper*: corresponding revisions to Table 1: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event.

NERC respectfully requests that the Commission accept the revised technical white papers and related development information, which includes the standard drafting team's consideration of stakeholder comments. These materials are attached hereto as **Attachment 1**.

Respectfully submitted,

/s/ Lauren A. Perotti

Lauren A. Perotti
Counsel for North American Electric Reliability Corporation

cc: Official service list in Docket No. RM15-11-000

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 28th day of June, 2016.

/s/ Lauren A. Perotti

Lauren A. Perotti
Counsel for North American
Electric Reliability Corporation

ATTACHMENT 1

Program Areas & Departments > Standards > Project 2013-03 Geomagnetic Disturbance Mitigation

Project 2013-03 Geomagnetic Disturbance Mitigation

Related Files

Status

A 30-day comment period on revised project white papers is available until **8 p.m. Eastern, Monday, June 13, 2016**.

Board Adopted: December 17, 2014 - TPL-007-1

Filed with FERC: January 21, 2015

Order Effective:

Enforcement Date:

Background:

FERC issued order 779 in May 2013 directing NERC to develop reliability standards to address the potential impact of geomagnetic disturbances (GMDs) on the reliability operation of the Bulk-Power System. Since 2010, industry has taken steps to address the GMD risk scenario identified in the 2010 High Impact Low Frequency (HILF) Event joint report through the Geomagnetic Disturbance (GMD) Task Force, which is comprised of industry representatives, government partners, and GMD experts. The GMD Task Force published an interim report on the effects of GMD on the Bulk-Power System in April 2012 and provided recommendations to manage risk. The task force's current project is focused on providing tools for system operators and planners to assess GMD effects on the system and implement mitigating strategies when needed.

Purpose / Industry Need:

Project 2013-03 will develop reliability standards to mitigate the risk of instability, uncontrolled separation, and Cascading as a result of geomagnetic disturbances (GMDs) through application of Operating Procedures and strategies that address potential impacts identified in a registered entity's assessment as directed in FERC Order 779.

While the impacts of space weather are complex and depend on numerous factors, space weather has demonstrated the potential to effect the reliable operation of the Bulk-Power System. During a GMD event, geomagnetically-induced current (GIC) flow in transformers may cause half-cycle saturation, which can increase absorption of Reactive Power, generate harmonic currents, and cause transformer hot spot heating. Increased transformer Reactive Power absorption and harmonic currents associated with GMD events can also cause protection system Misoperation and loss of Reactive Power sources, the combination of which can lead to voltage collapse.

The project will develop requirements for registered entities to employ strategies that mitigate risks of instability, uncontrolled separation and Cascading caused by GMD in two stages as directed in order 779:

1. Stage 1 standard(s) will require applicable registered entities to develop and implement Operating Procedures that can mitigate the effects of GMD events.
2. Stage 2 standard(s) will require applicable registered entities to conduct initial and on-going assessments of the potential impact of benchmark GMD events on their respective system as directed in order 779. The Second Stage GMD Reliability Standards must identify benchmark GMD events that specify what severity GMD events applicable registered entities must assess for potential impacts on the Bulk-Power System. If the assessments identify potential impacts from benchmark GMD events, the Reliability Standards will require the registered entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading as a result of a benchmark GMD event. The development of this plan cannot be limited to considering operational procedures or

enhanced training alone, but will, subject to the potential impacts of the benchmark GMD events identified in the assessments, contain strategies for mitigating the potential impact of GMDs based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment.

As directed in order 779, stage 1 standards must be filed by January 2014, and stage 2 standards must be filed by January 2015.

Draft	Action	Dates	Results	Consideration of Comments
Project White Papers Benchmark GMD Event White Paper **(11)**[unchanged from clean version below] Thermal Screening Criterion White Paper **(12)** [unchanged from clean version below] Transformer Thermal Impact Assessment White Paper Clean **(13)** | Redline to Last Posted **(14)**				
Revisions to Project White Papers Benchmark GMD Event White Paper Clean **(1)** | Redline to Last Posted **(2)** Transformer Thermal Impact Assessment White Paper	Comment Period Info **(8)** Submit Comments	05/12/16 - 06/13/16	Comments Received **(9)**	Consideration of Comments **(10)**

Clean **(3)** | Redline to Last Posted **(4)** Thermal Screening Criterion White Paper Clean **(5)**| Redline to Last Posted **(6)** **Supporting Materials** Unofficial Comment Form (Word) **(7)**				

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation
Standard Drafting Team
May 12, 2016

RELIABILITY | ACCOUNTABILITY





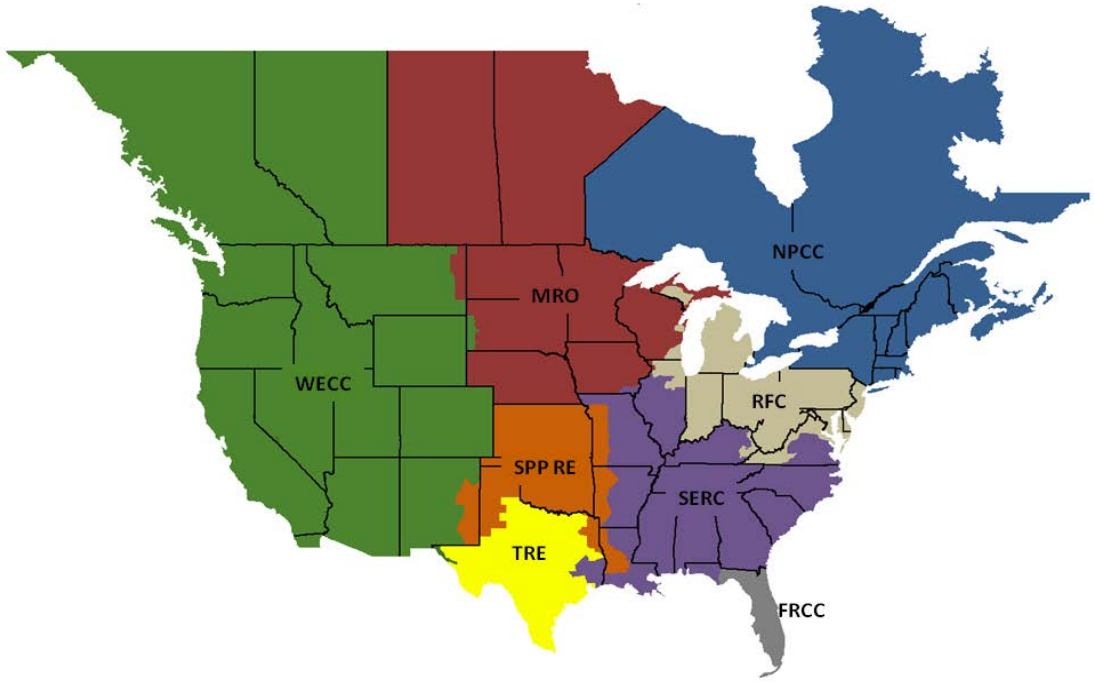

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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure 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 several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances 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 developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape 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 magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. Since geomagnetic disturbance impacts within areas of influence of approximately 100-200 km do not have a widespread impact on the interconnected transmission system (see Appendix I), statistical methods used to assess the frequency of occurrence of a severe GMD event need to consider broad geographical regions to avoid bias caused by spatially localized geomagnetic phenomena.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. The benchmark 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 waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. 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 II) resulted in a conservative peak geoelectric field amplitude of approximately 8 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 frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

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 8 V/km using the following relationship

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

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 (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the

reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is 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 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

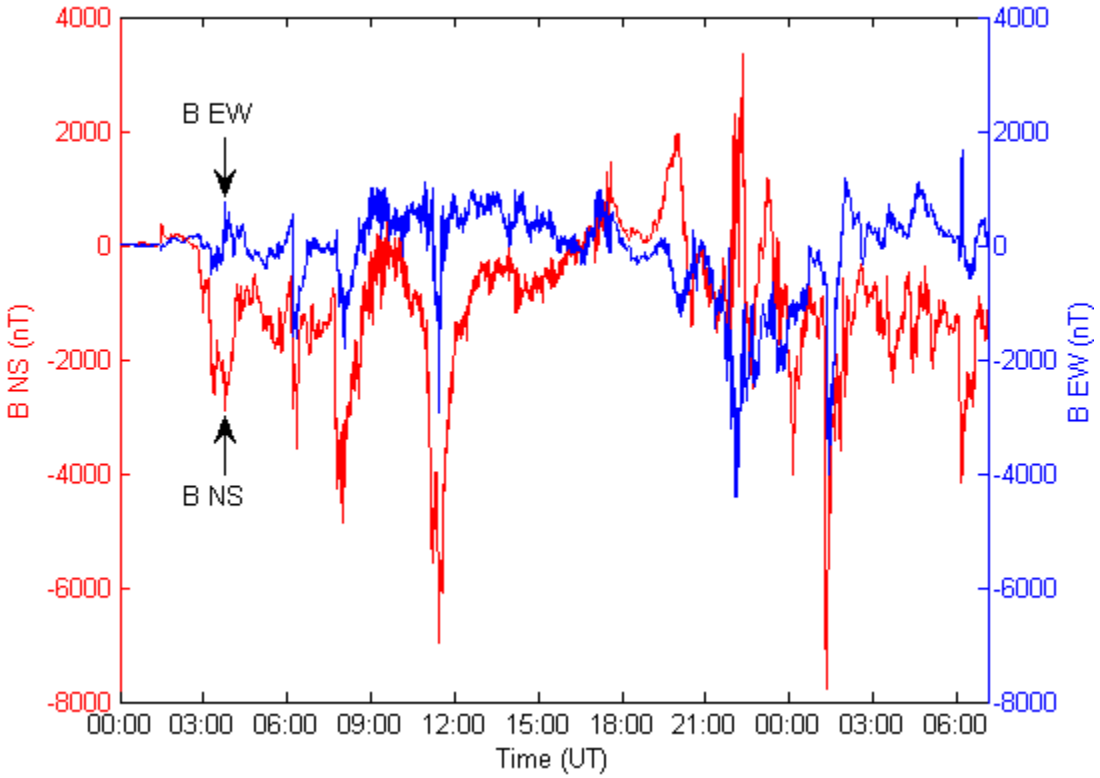


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

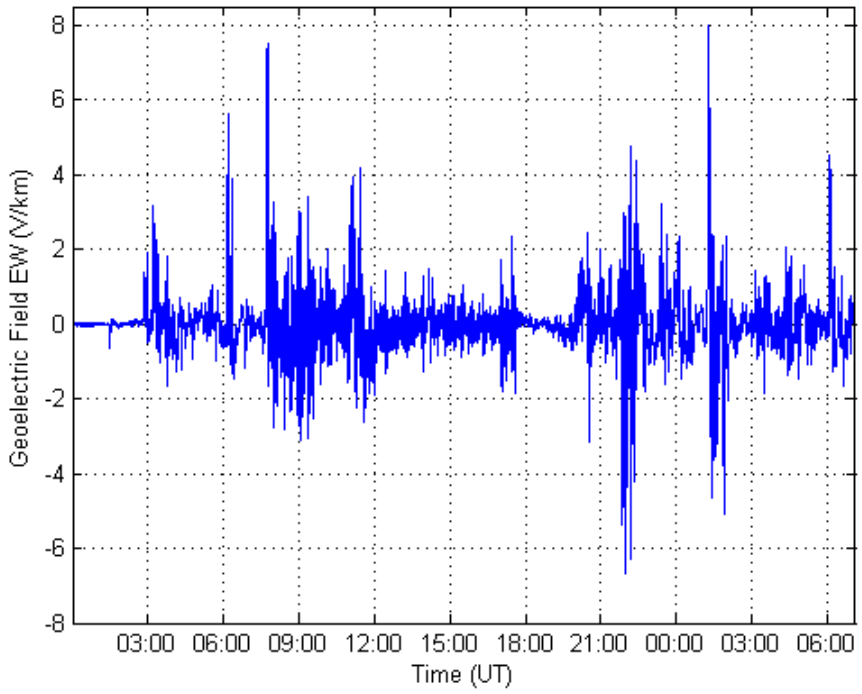


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

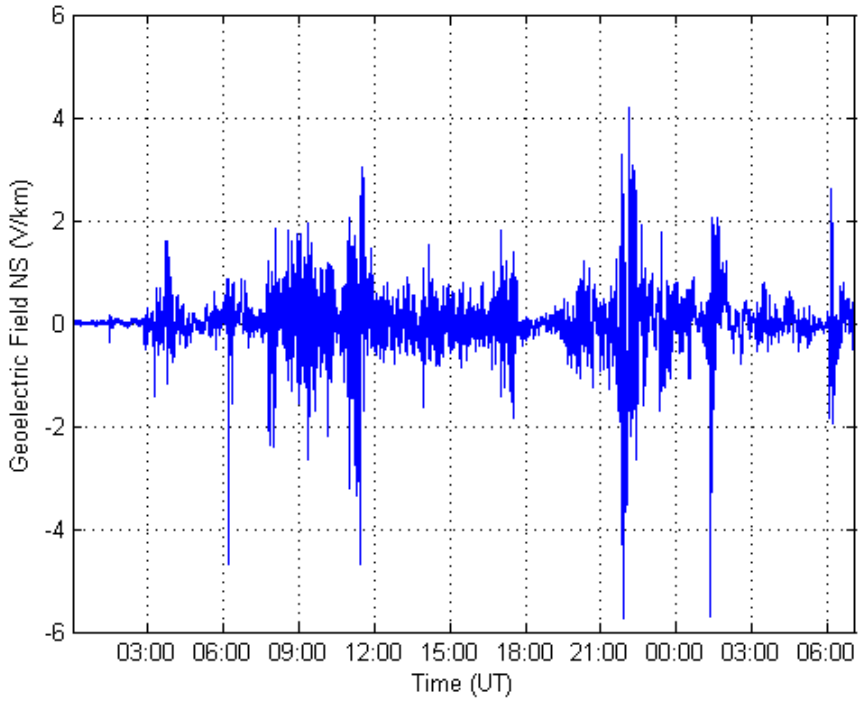


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** 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.

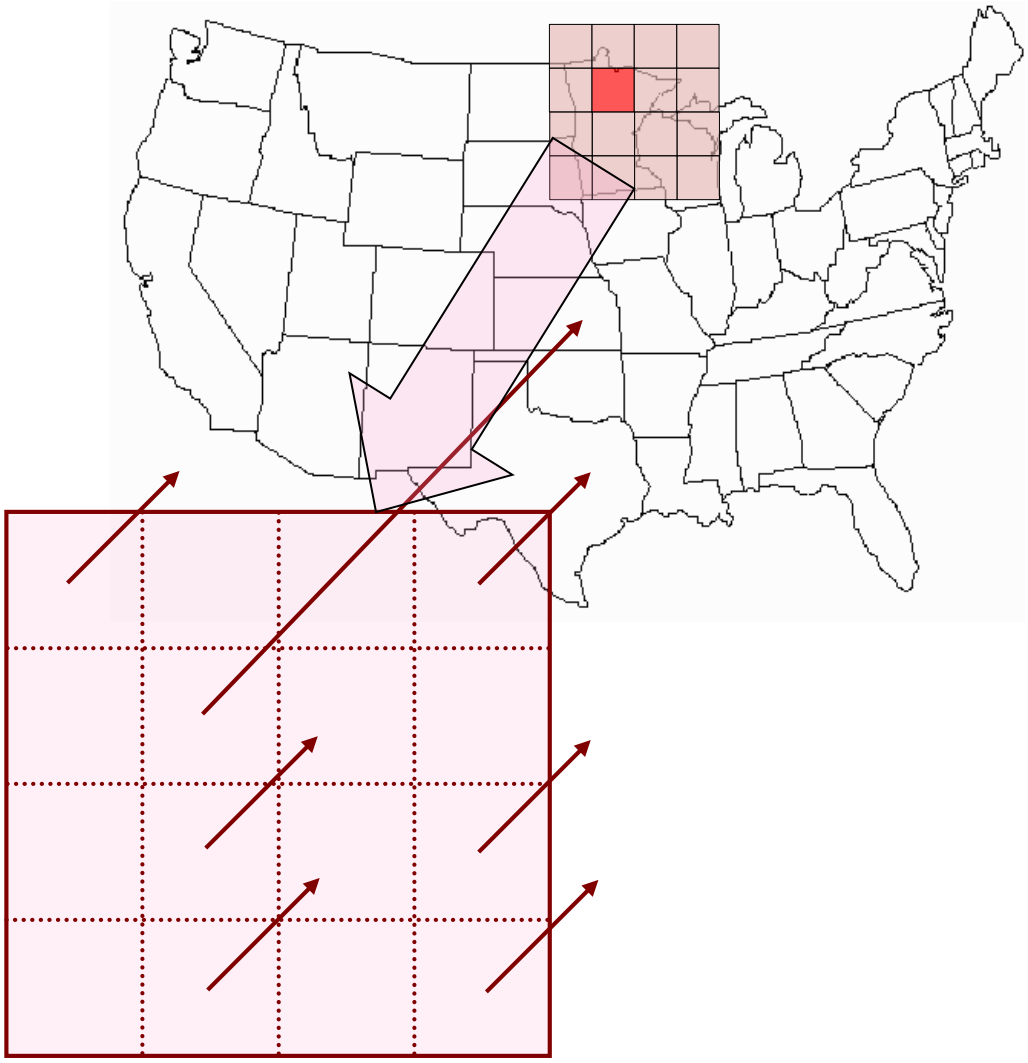


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

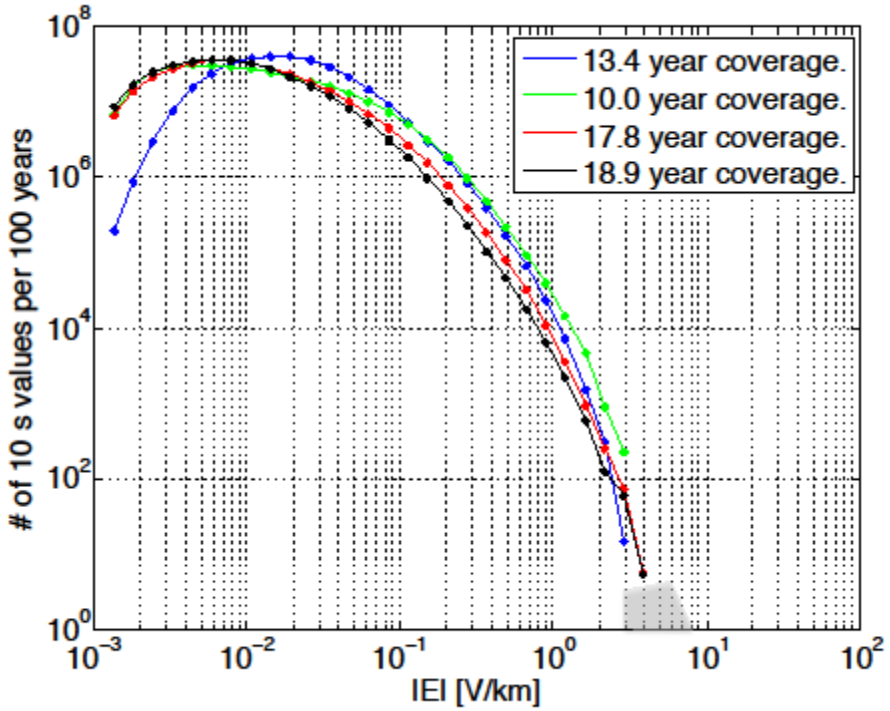


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes.
Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

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 percent confidence interval of the maximum geoelectric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

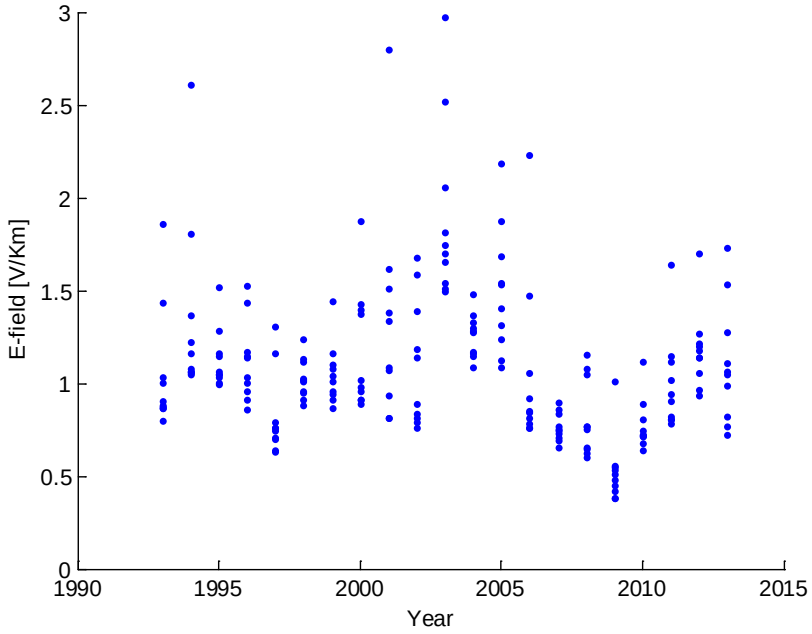


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

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 [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT 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 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] 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.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

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 Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization 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: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The benefit is an increase in the mean return

level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] 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 1 V/km; the data was de-clustered 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; a threshold that is too low will likely lead to bias. On the other hand, a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size, the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used 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 statistically significant; the null hypothesis, H0: $\alpha_1=0$, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). 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.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis is consistent with the selection of a geoelectric field amplitude of 8 V/km for the 100-year GMD benchmark. .

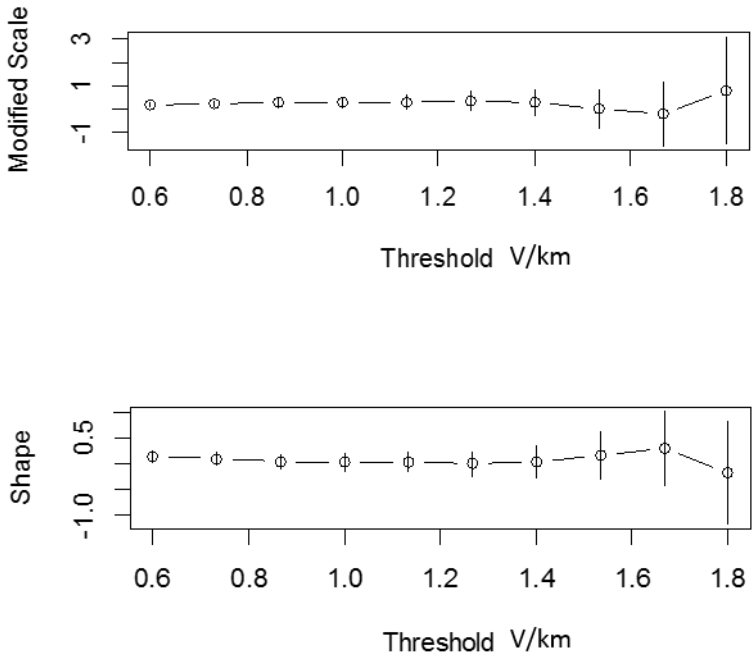


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

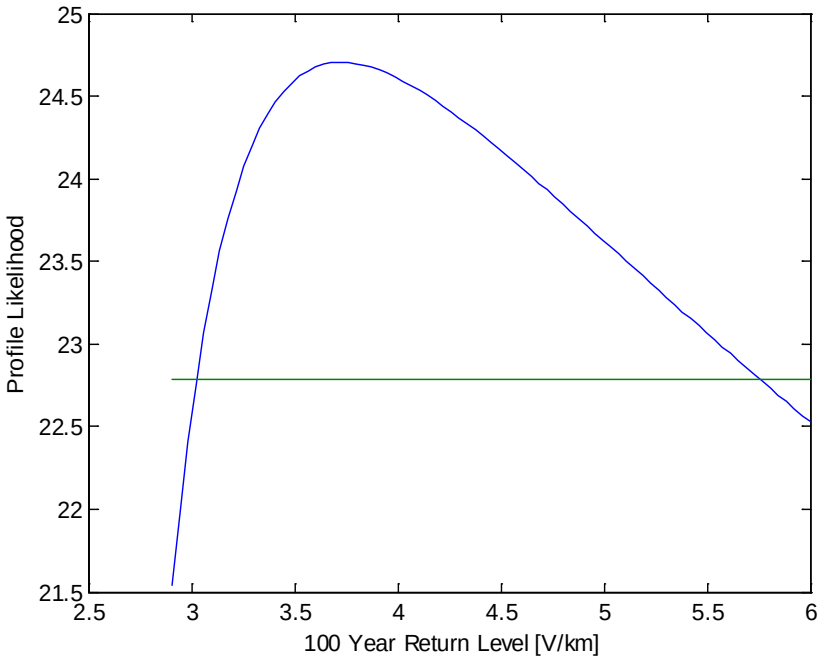


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

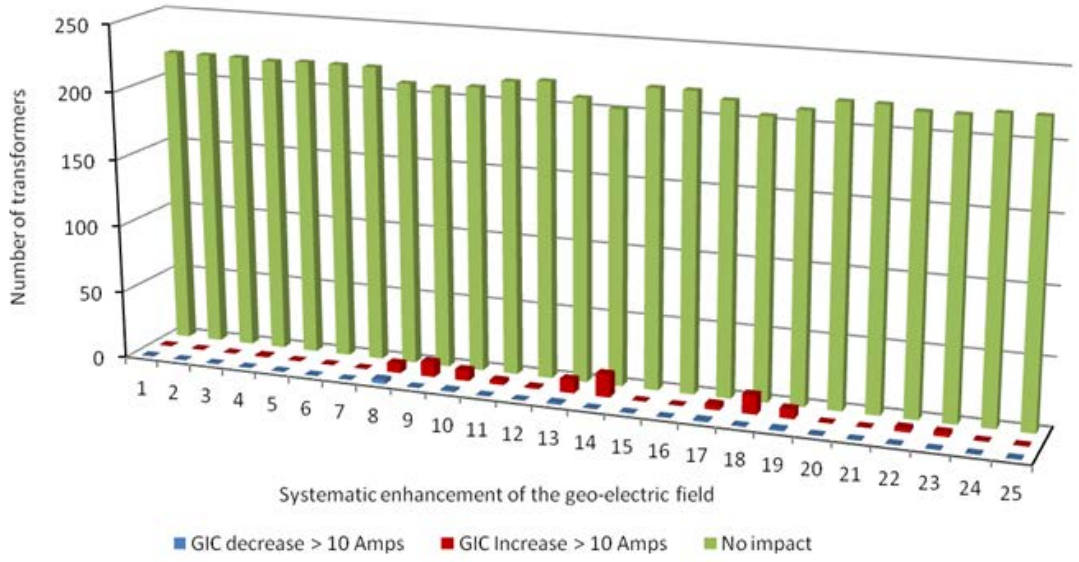


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

as the measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003 described in the NERC GMD interim report of 2012 [14].

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. **Figure I-9** shows a more systematic way to compare the relative effects of storm waveshape on the thermal response of a transformer. It shows the results of 33,000 thermal assessments for all combinations of effective GIC due to circuit orientation (similar **to Figures I-7** and **I-8** but systematically taking into account all possible circuit orientations). These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

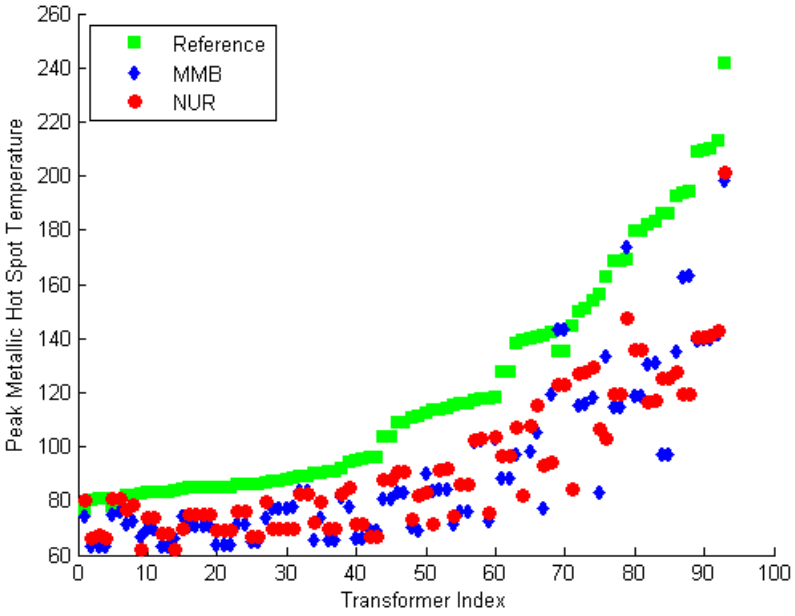


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

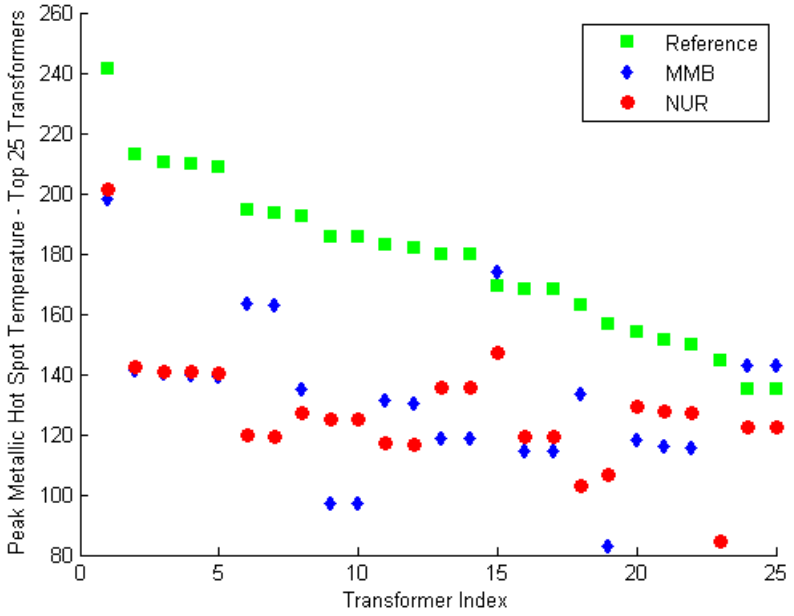


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field

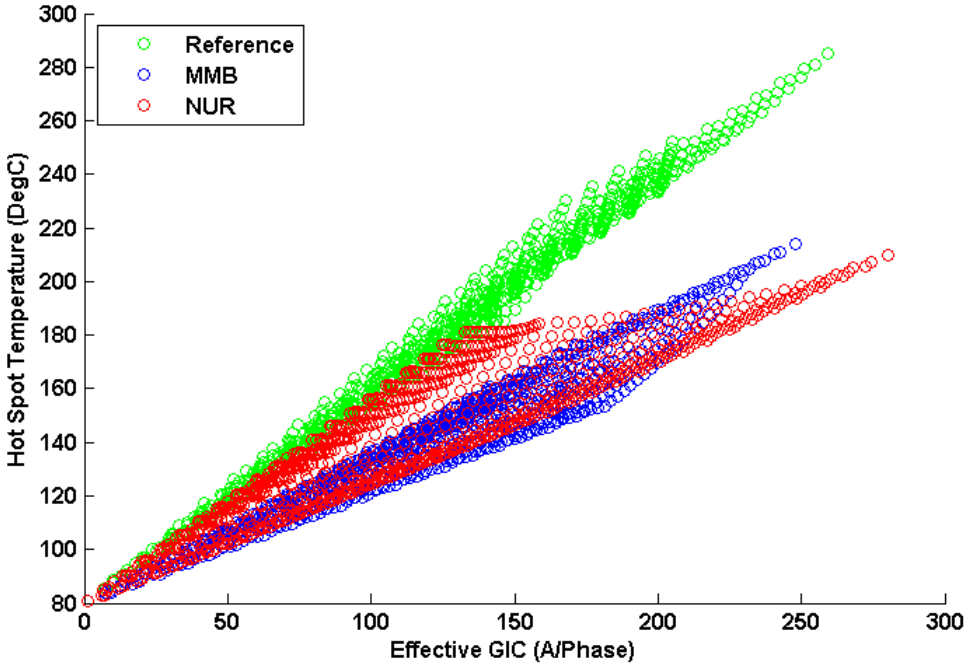


Figure I-9: Calculated Peak Metallic Hot Spot Temperature for all possible circuit orientations and effective GIC.

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]**.** 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 Geomagnetic Field

The benchmark 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 reference geomagnetic field waveshape 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], [24]-[25], 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 $0.1 \leq \alpha \leq 1.0$.

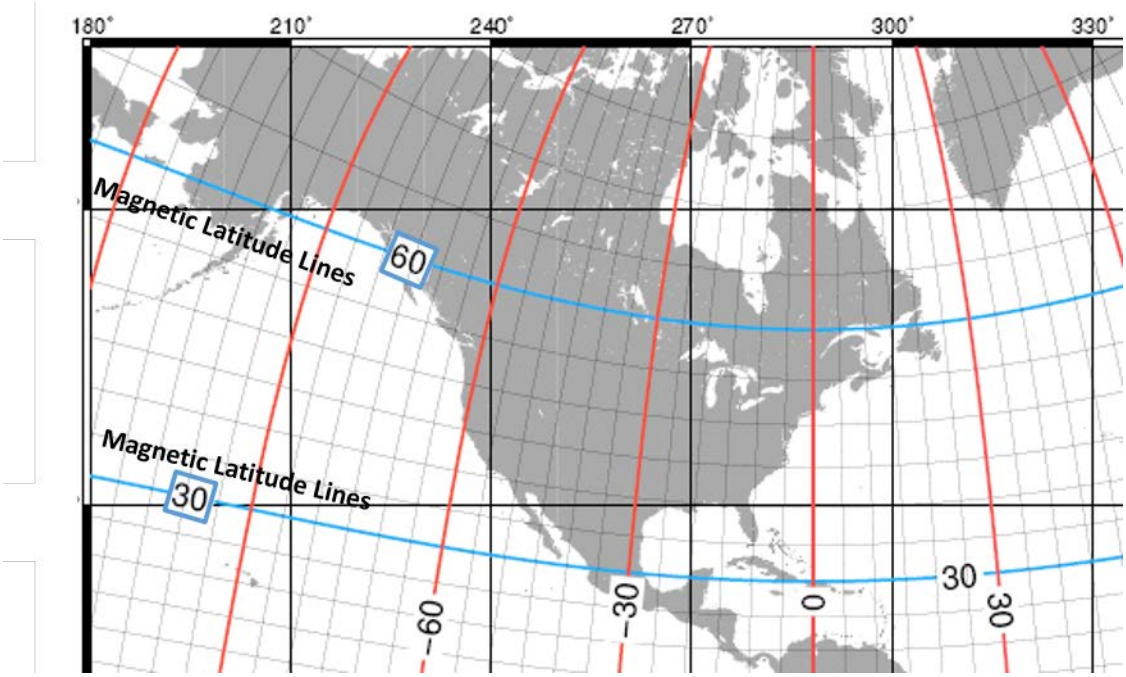


Figure II-1: Geomagnetic Latitude Lines in North America

[6] 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.

[7] 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.

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 benchmark 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 [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$E_N = (z(t)/\mu_o) * B_E(t)$$
$$E_E = -(z(t)/\mu_o) * B_N(t) \qquad \text{(II.2)}$$
$$E_{peak} = \max\left\{\left|E_E(t), E_N(t)\right|\right\}$$

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 waveshapes,

$E_E(t)$, $E_N(t)|$ 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.

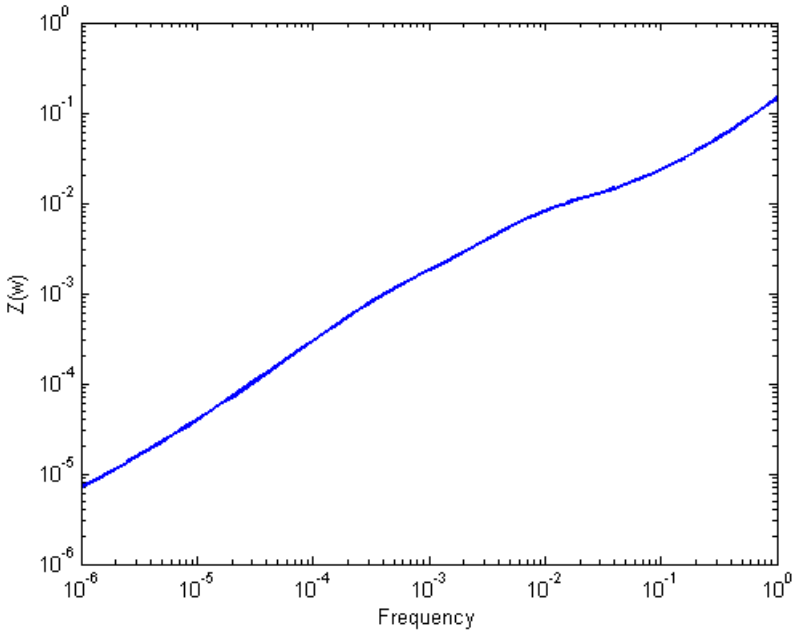


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β 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)

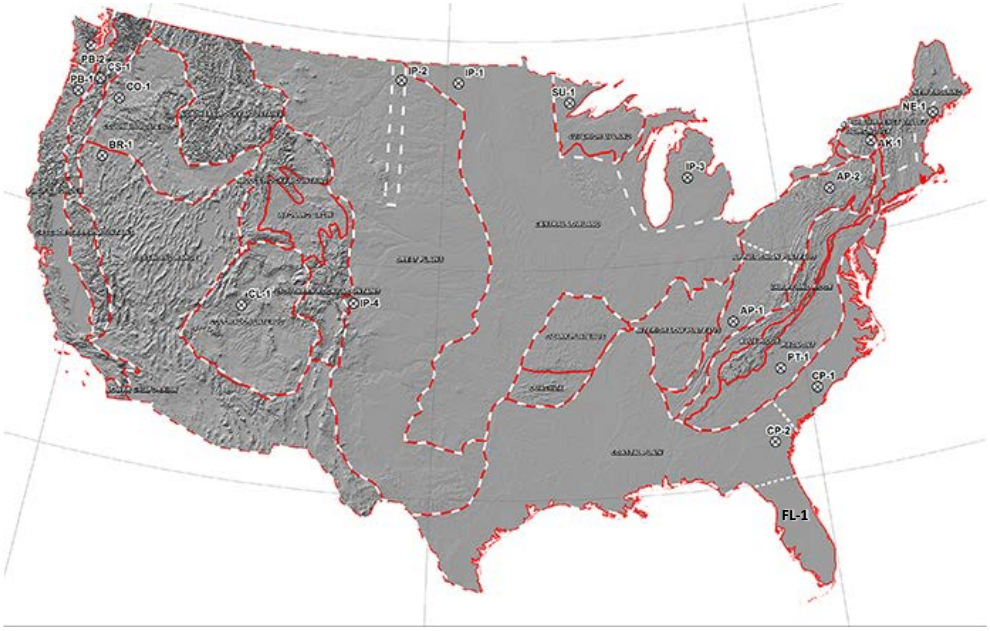
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad \text{(II.3)}$$

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.
- 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 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 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference 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. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second recordings for these geomagnetic field time series.
- 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 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 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

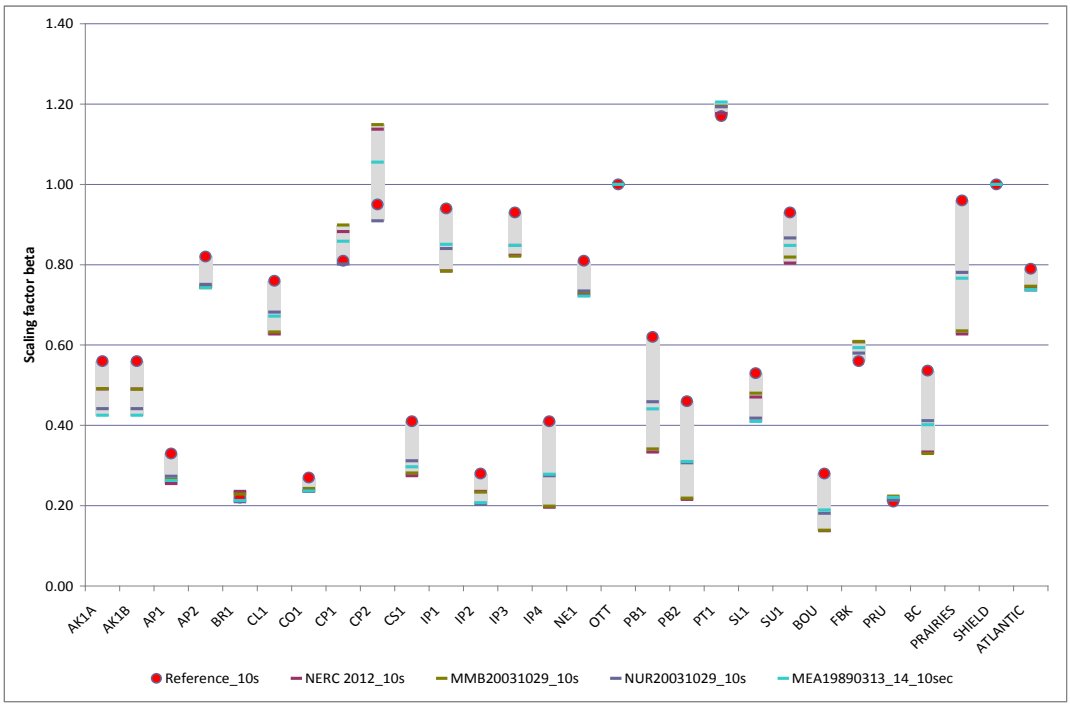


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles correspond to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5 V/km$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity than the reference benchmark conductivity, therefore, according to the conductivity factor β from Table II-2., the calculation follows:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2V / km$$

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation
Standard Drafting Team

~~December 5, 2014~~May 12, 2016

RELIABILITY | ACCOUNTABILITY



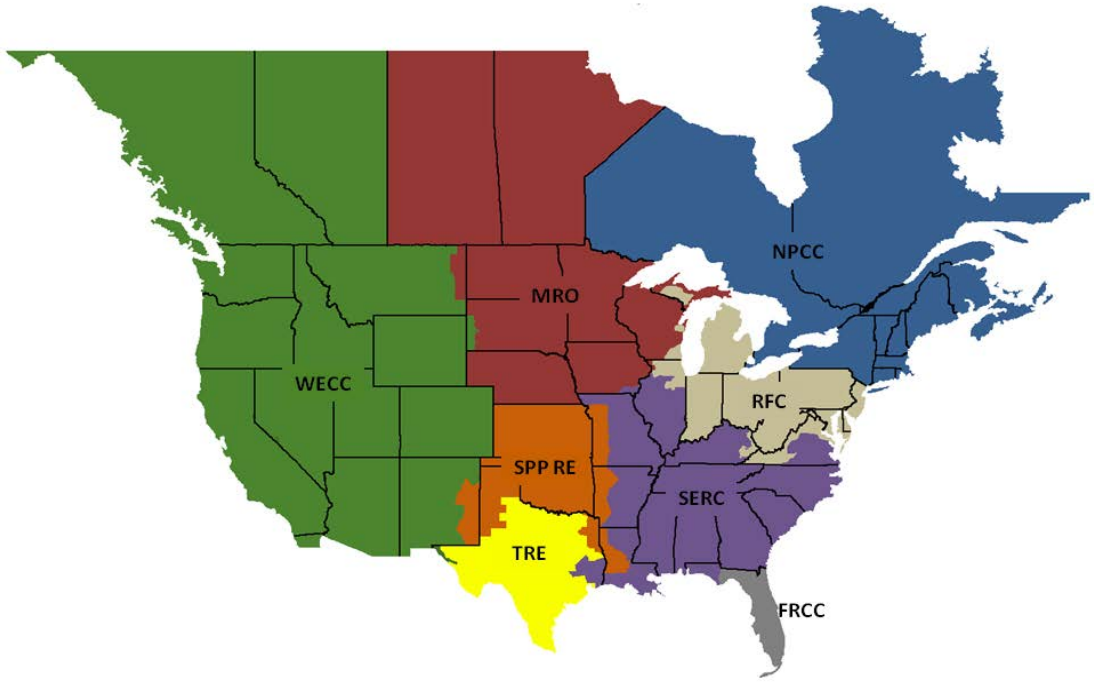
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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure 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 several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances 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 developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape 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 magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. Since geomagnetic disturbance impacts within areas of influence of approximately 100-200 km do not have a widespread impact on the interconnected transmission system (see Appendix I), statistical methods used to assess the frequency of occurrence of a severe GMD event need to consider broad geographical regions to avoid bias caused by spatially localized geomagnetic phenomena.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. The benchmark 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 waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. 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 II) resulted in a conservative peak geoelectric field amplitude of approximately 8 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 frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

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 8 V/km using the following relationship

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

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 (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the

reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is 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 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

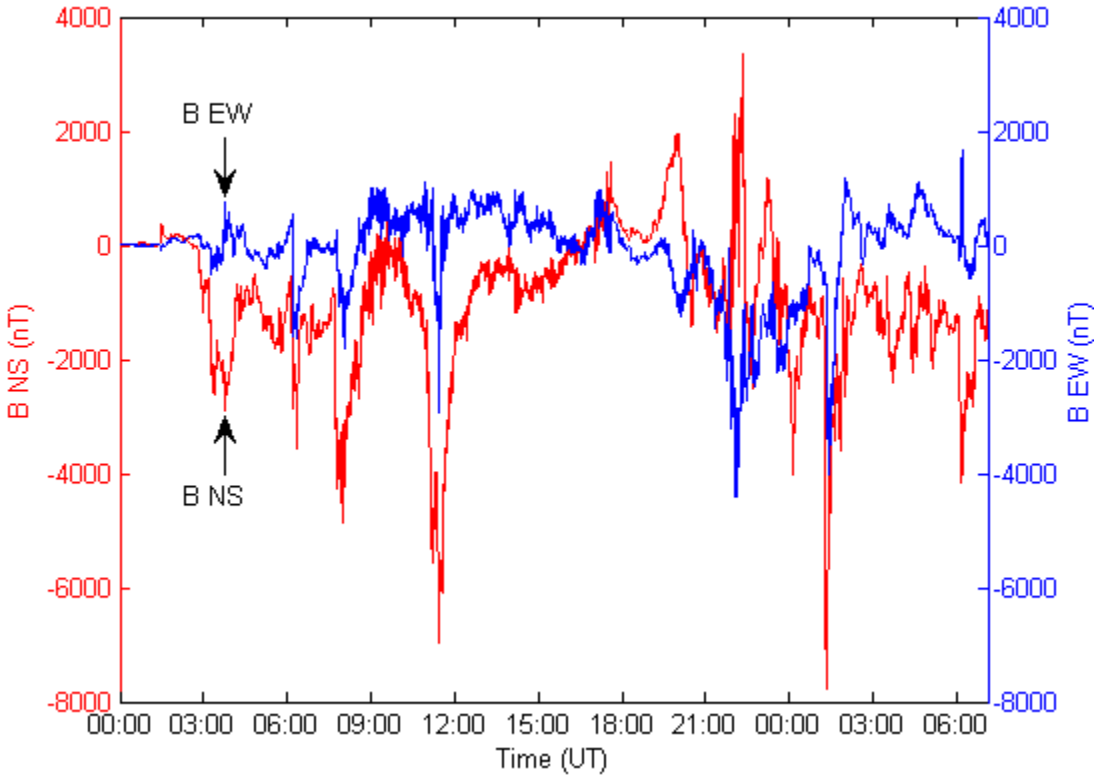


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

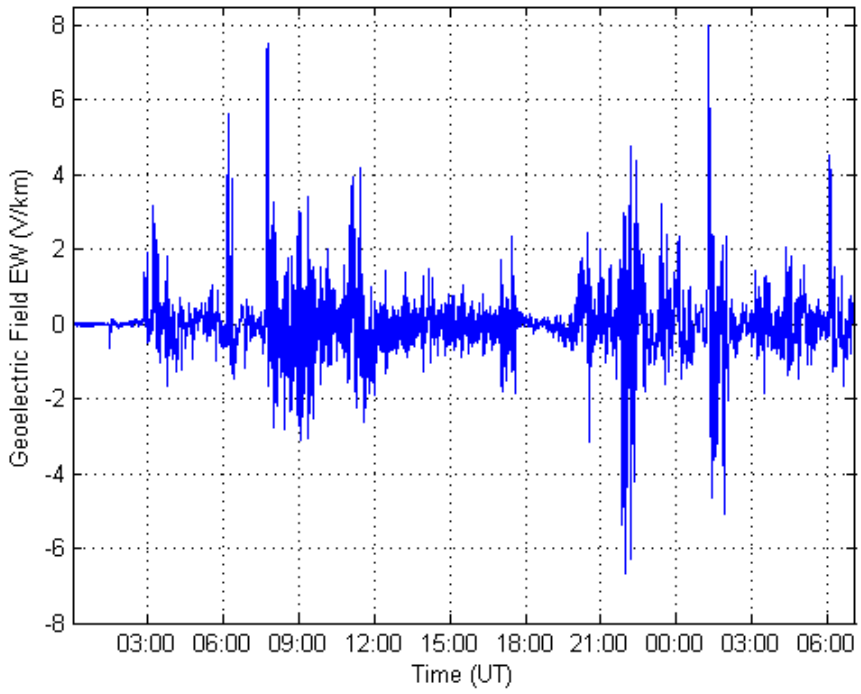


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

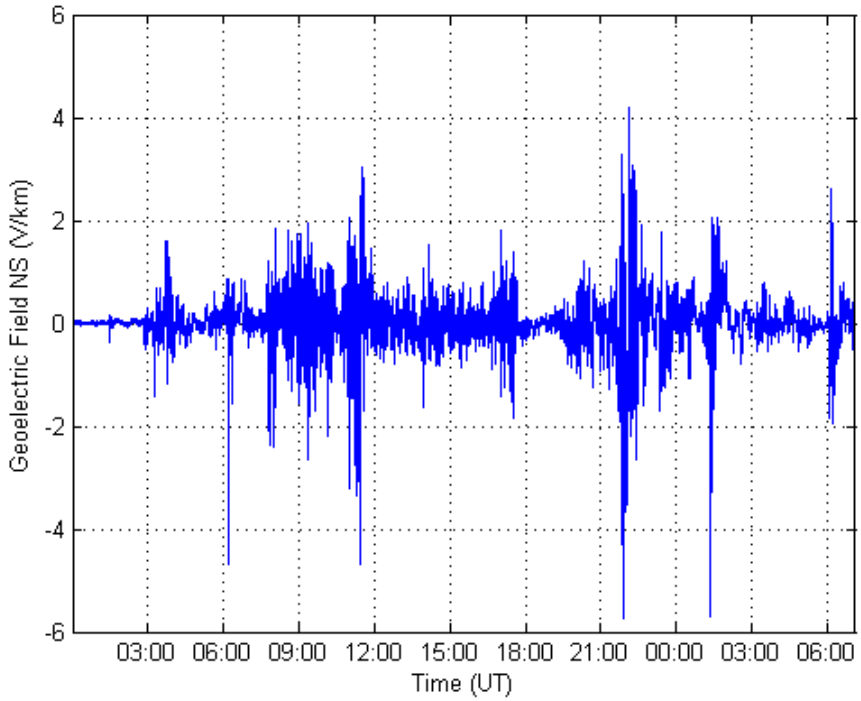


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** 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.

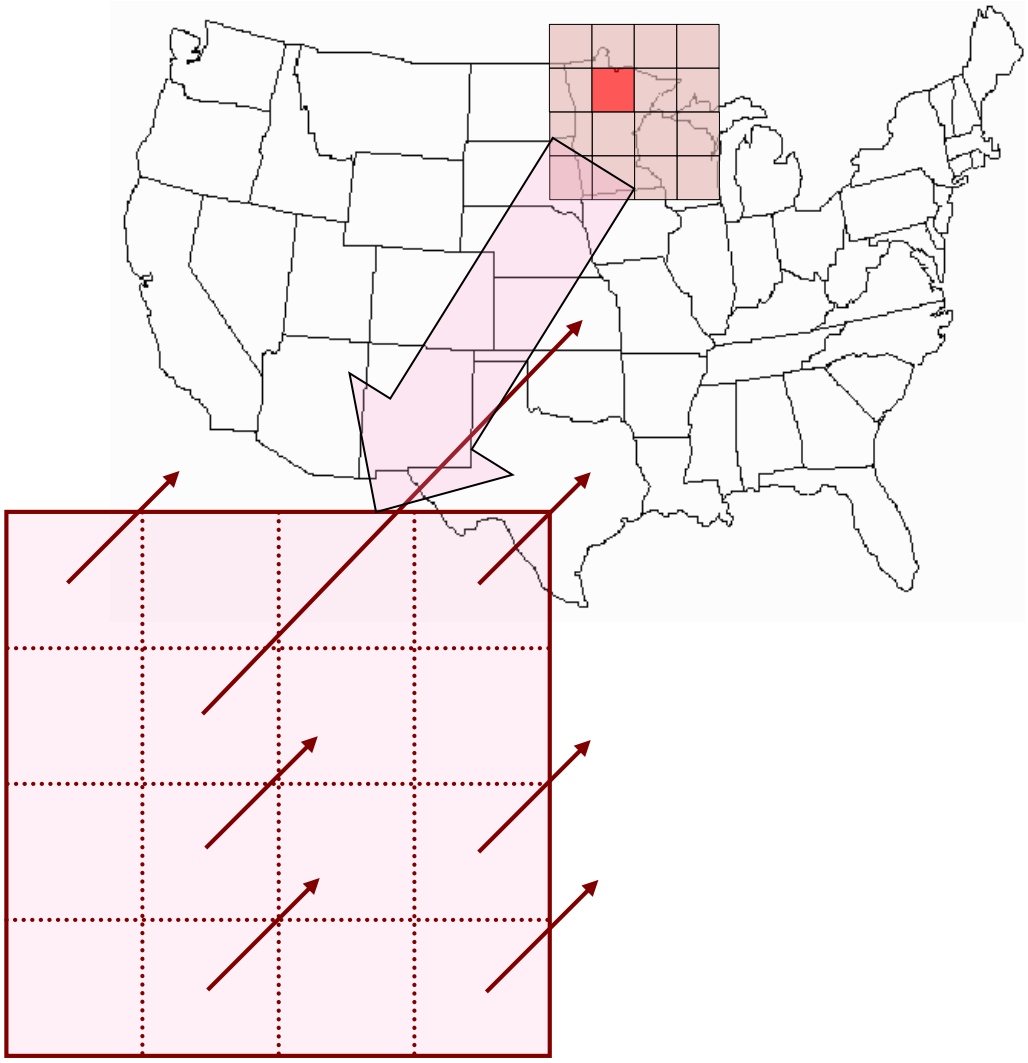


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

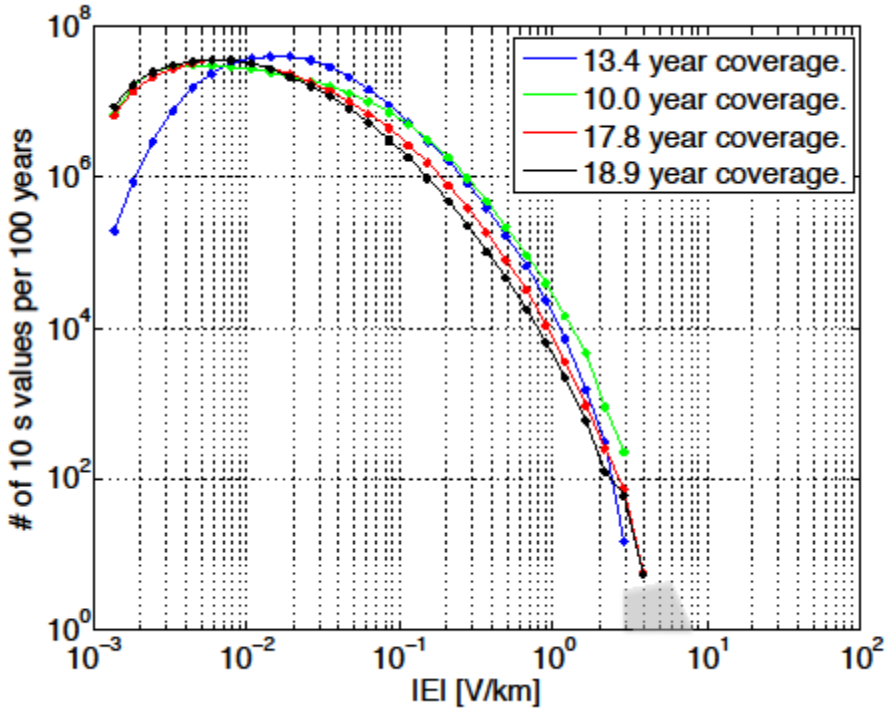


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes.
Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

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 percent confidence interval of the maximum geoelectric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

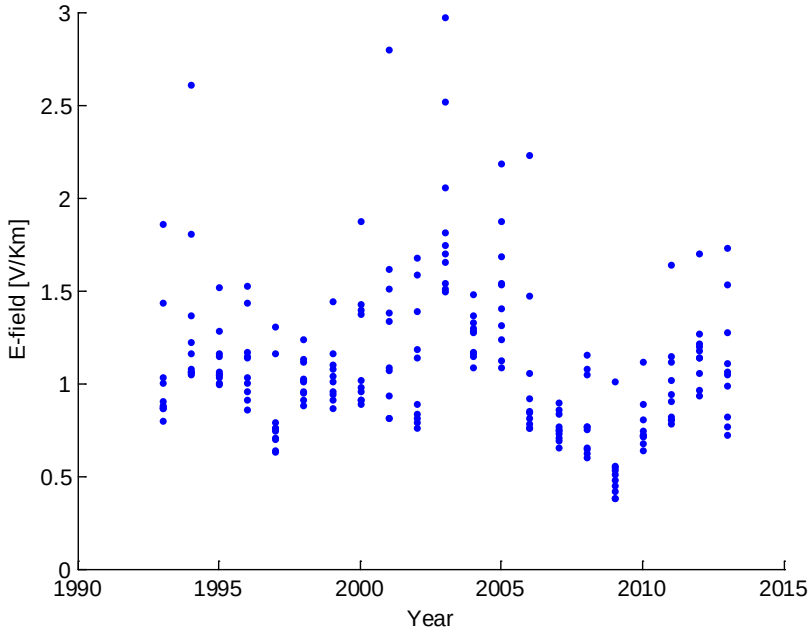


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

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 [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT 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 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] 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.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

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 Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization 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: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The benefit is an increase in the mean return

level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] 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 1 V/km; the data was de-clustered 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; a threshold that is too low will likely lead to bias. On the other hand, a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size, the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used 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 statistically significant; the null hypothesis, H0: $\alpha_1=0$, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). 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.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis is consistent with the selection of a geoelectric field amplitude of 8 V/km for the 100-year GMD benchmark. .

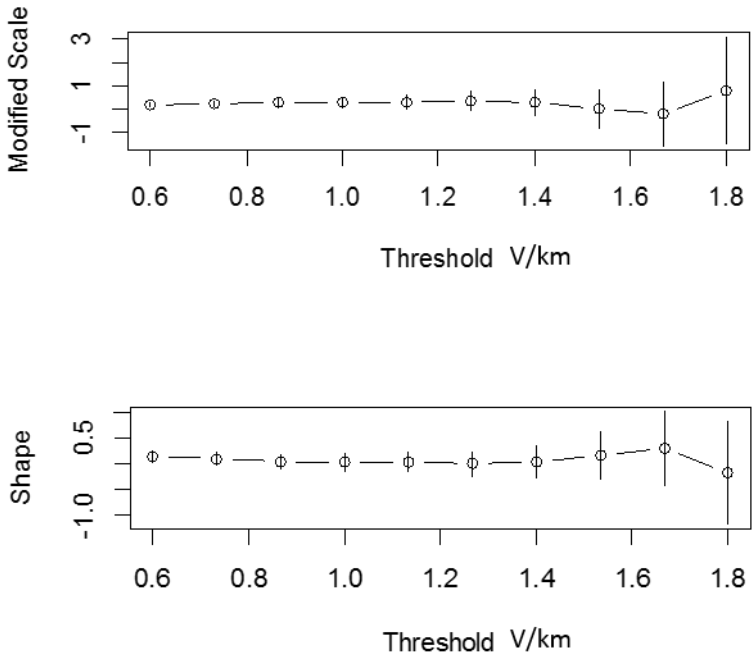


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

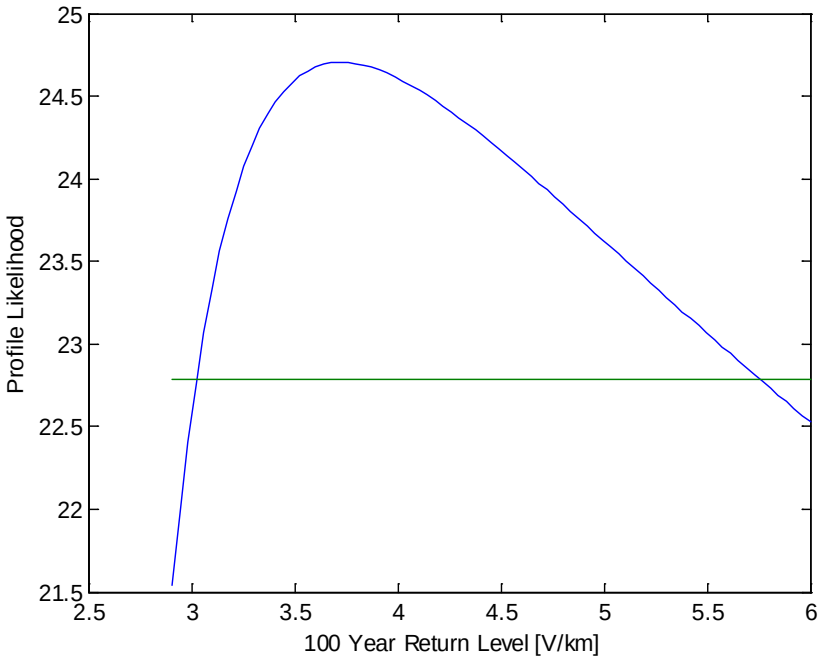


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

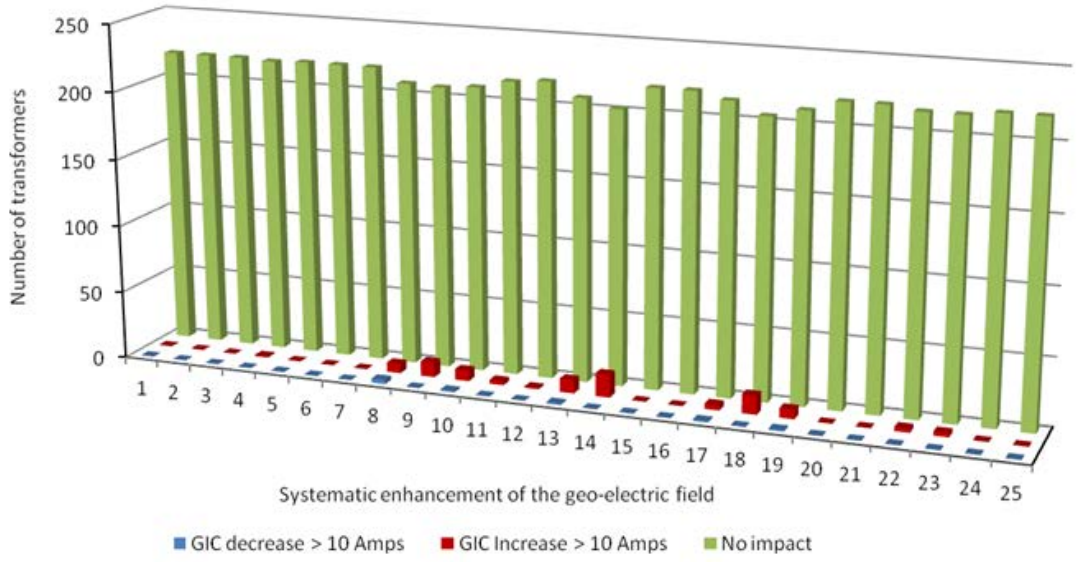


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

as the ~~reference storm of the NERC interim report of 2012 [14], and~~ measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003~~.~~ described in the NERC GMD interim report of 2012 [14].

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. **Figure I-9** shows a more systematic way to compare the relative effects of storm waveshape on the thermal response of a transformer. It shows the results of 33,000 thermal assessments for all combinations of effective GIC due to circuit orientation (similar **to Figures I-7** and **I-8** but systematically taking into account all possible circuit orientations). These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

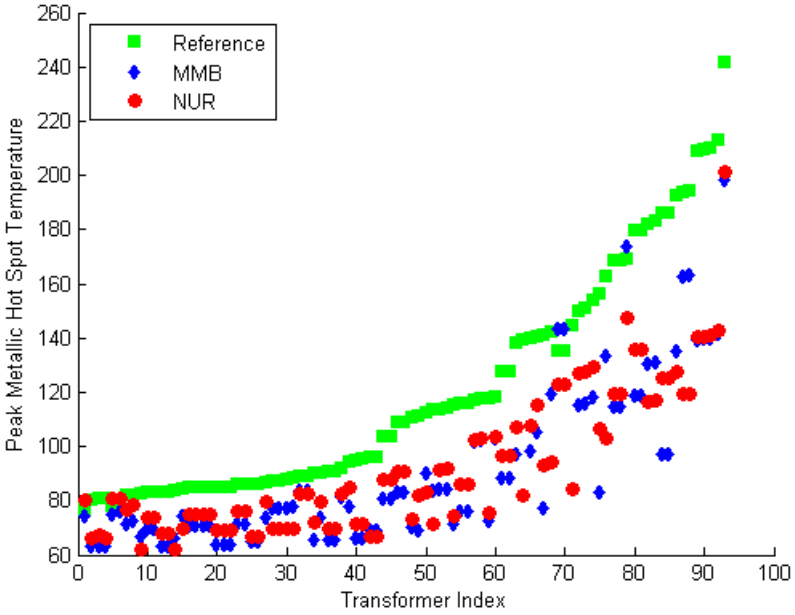


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

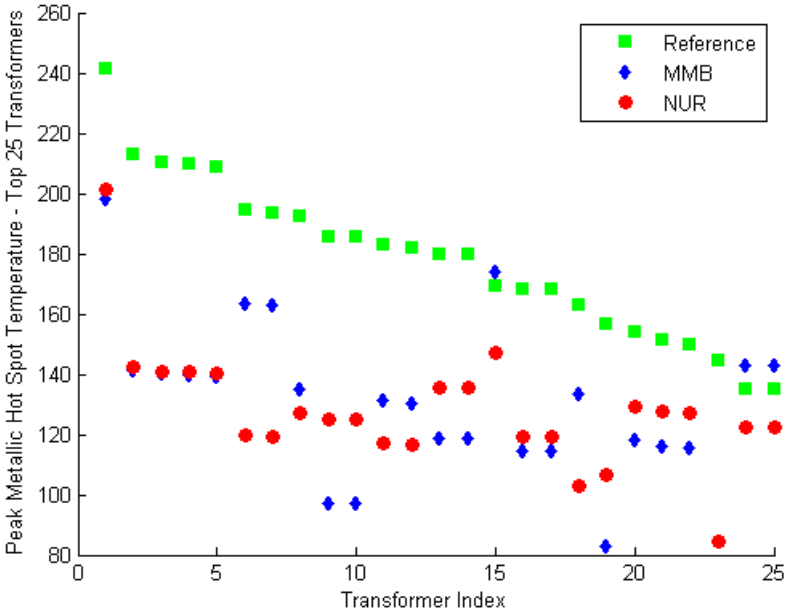
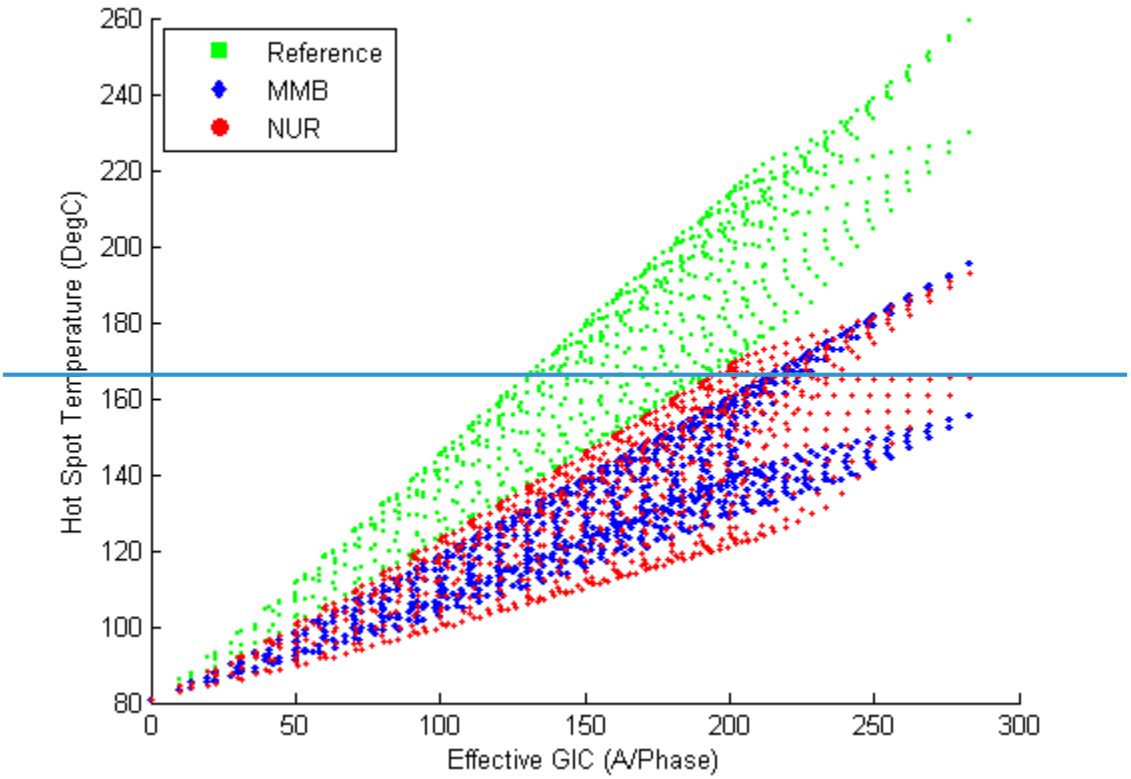


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field



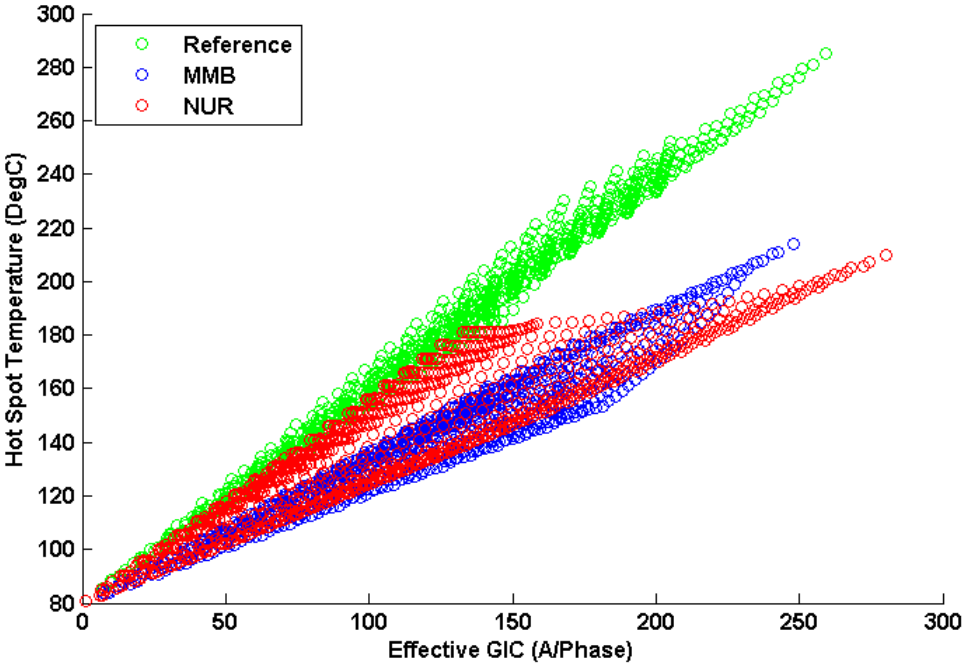


Figure I-9: Calculated Peak Metallic Hot Spot Temperature for all possible circuit orientations and effective GIC.

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]**.** 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 Geomagnetic Field

The benchmark 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 reference geomagnetic field waveshape 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], [24]-[25], 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 $0.1 \leq \alpha \leq 1.0$.

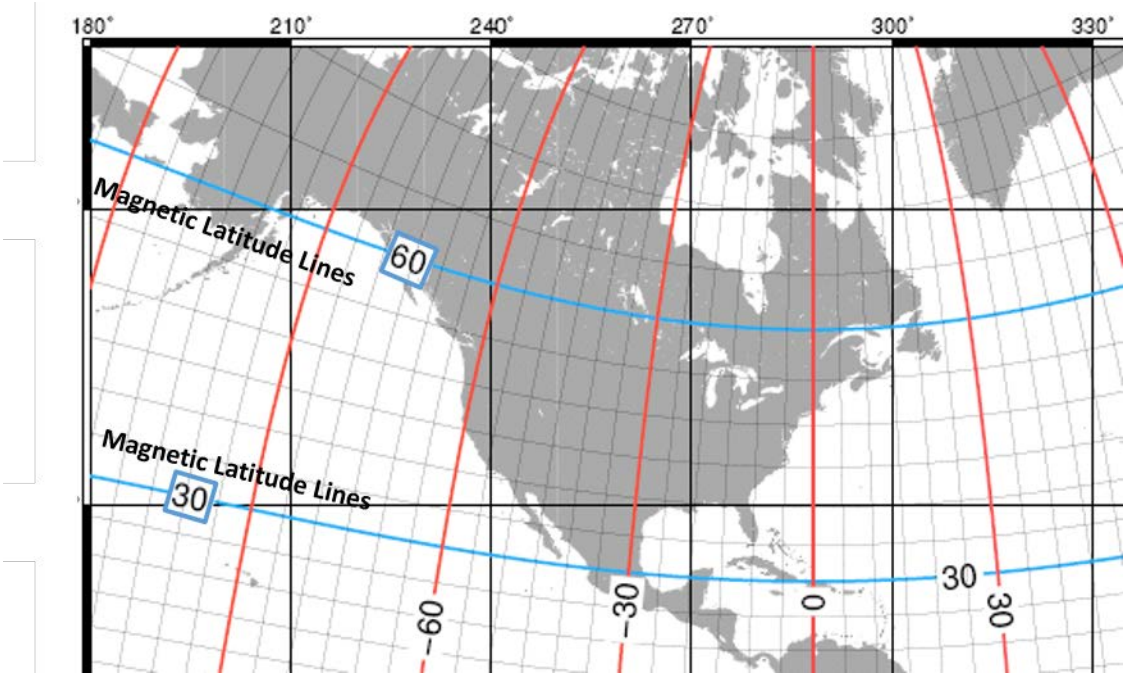


Figure II-1: Geomagnetic Latitude Lines in North America

[6] 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.

[7] 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.

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 benchmark 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 [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$E_N = (z(t)/\mu_o) * B_E(t)$$
$$E_E = -(z(t)/\mu_o) * B_N(t) \qquad \text{(II.2)}$$
$$E_{peak} = \max\left\{\left|E_E(t), E_N(t)\right|\right\}$$

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 waveshapes,

$E_E(t)$, $E_N(t)|$ 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.

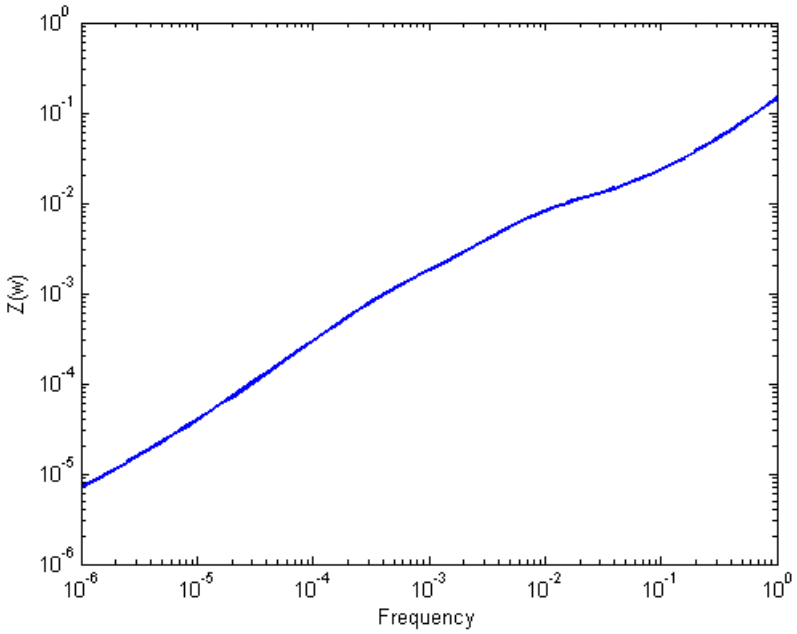


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β 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)

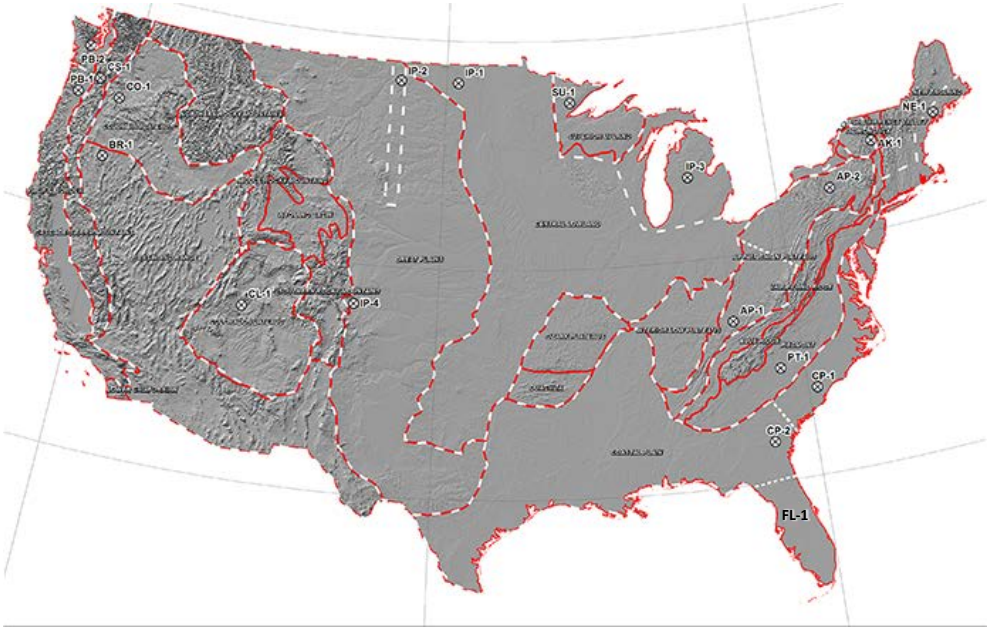
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad \text{(II.3)}$$

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.
- 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 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 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference 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. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second recordings for these geomagnetic field time series.
- 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 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 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

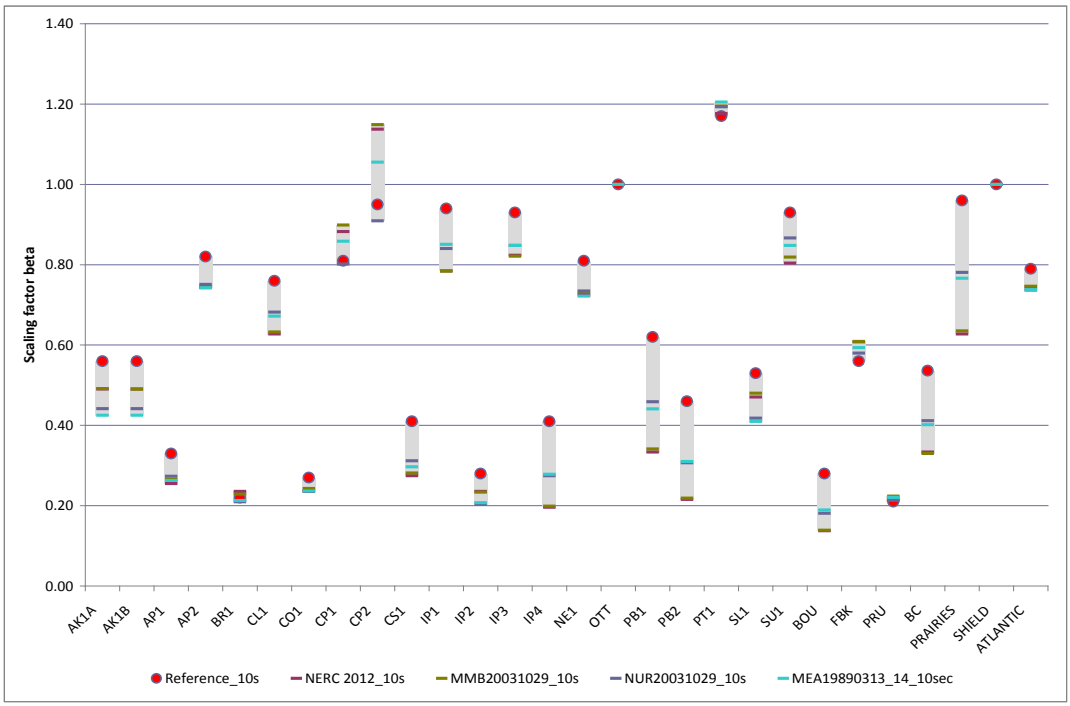


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles correspond to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5 V/km$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity than the reference benchmark conductivity, therefore, according to the conductivity factor β from Table II-2., the calculation follows:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2V / km$$

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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 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.

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.

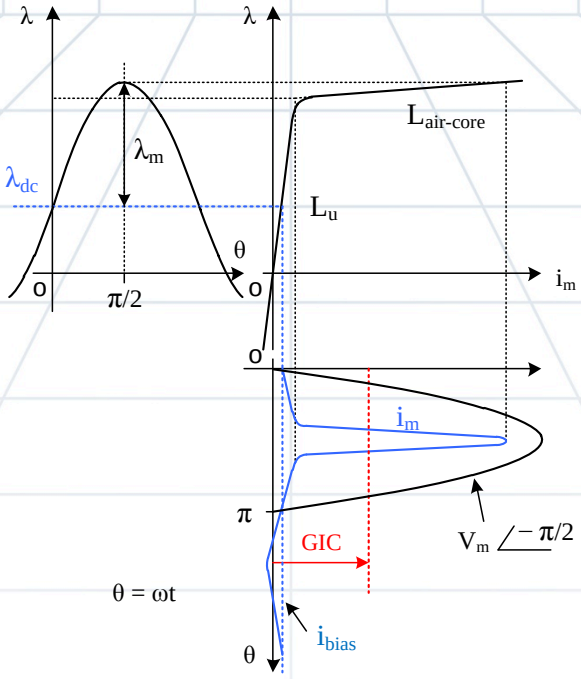


Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

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] for hot spot heating during short-term emergency operation. 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 "waveshape" 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 2 from the "Screening Criterion for Transformer Thermal Impact Assessment" white paper [7]. This table, shown as Table 1 below, provides the peak metallic hot spot temperatures that can be reached using conservative thermal models. To use Table 1, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after 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.

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

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. All thermal assessment methods should be demonstrably equivalent to assessments that use the benchmark GMD event.

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 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. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC waveshape 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.

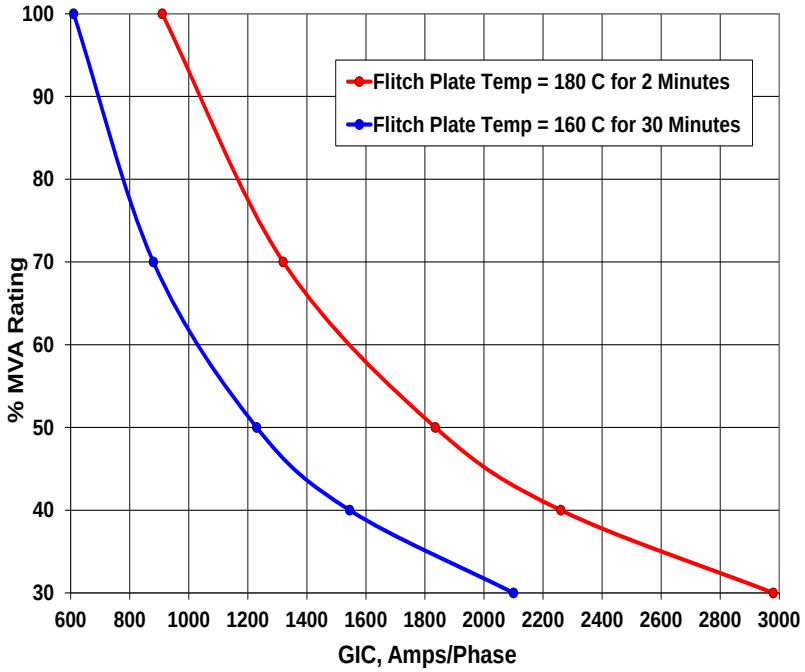


Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[1]. The input to this type of simulation is the time series or waveshape 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] 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]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[1] Technical details of this methodology can be found in [4].

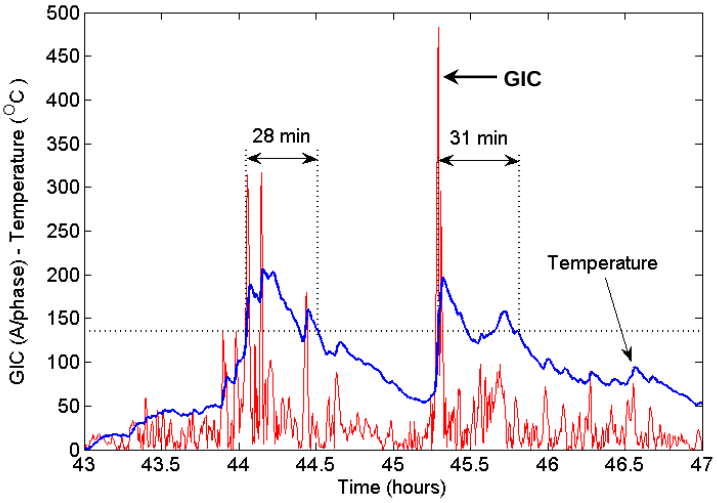


Figure 3: Sample Tie Plate Temperature Calculation
Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" 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 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].

$$GIC(t) = \left|E(t)\right| \cdot \left\{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\right\} \quad (2)$$

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/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] after the appropriate geomagnetic latitude scaling factor α is applied[2]. 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 conductivity scaling factor β[3]. 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]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)} \quad (6)$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)} \quad (7)$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

[2] 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.

[3] 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.

It should be emphasized that even for the same reference event, the GIC(t) waveshape 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 to test all transformers is incorrect.

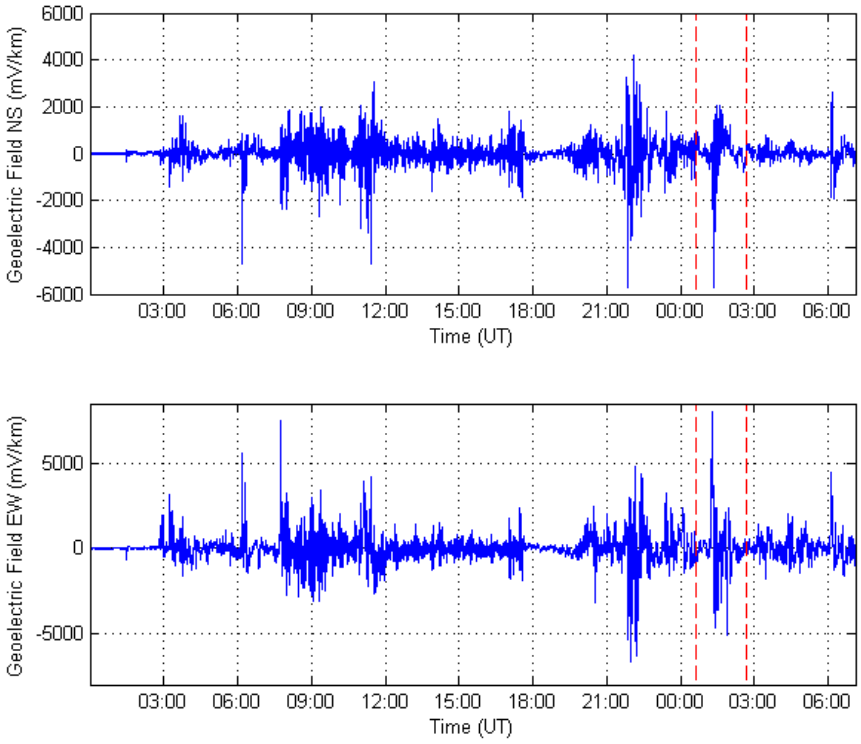


Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

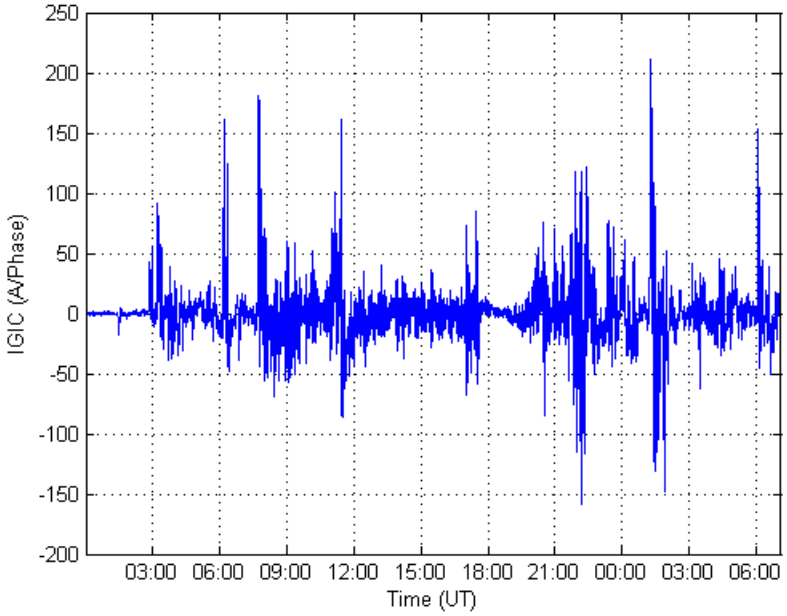


Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

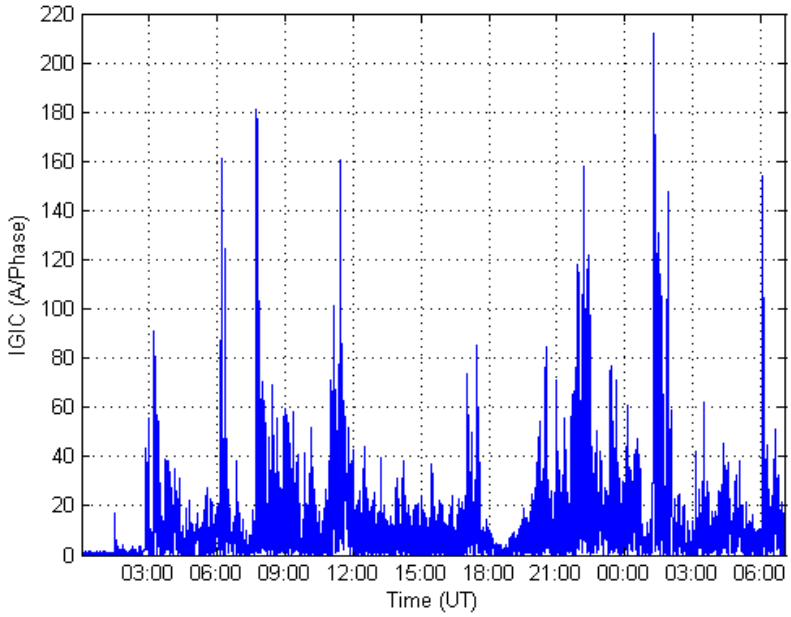


Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

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] 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.[4]

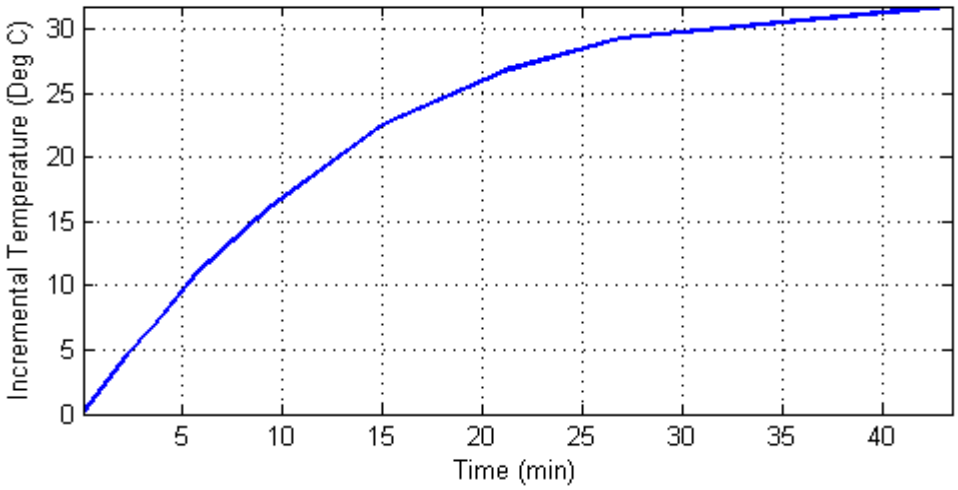


Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step
Metallic hot spot heating.

[4] 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.

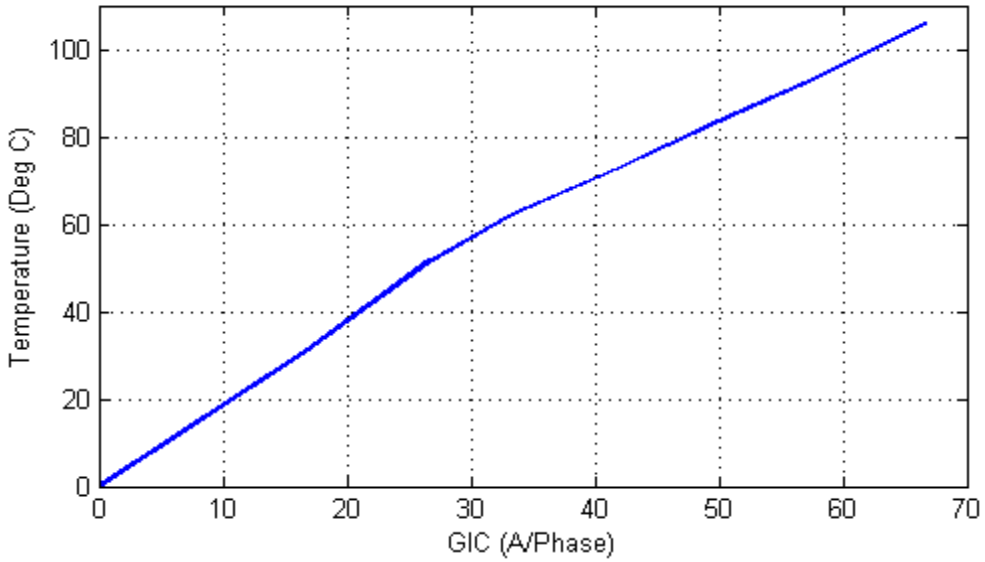


Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

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.

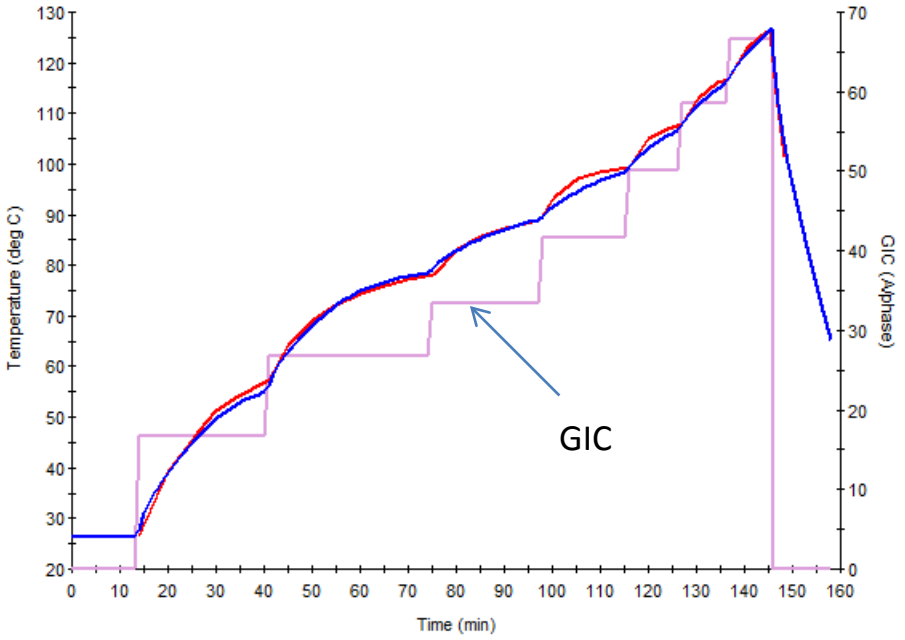


Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). Injected current is represented by the magenta trace.

To obtain the thermal response of the transformer to a GIC waveshape 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 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. 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 hot spot temperature time series $\theta(t)$. **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

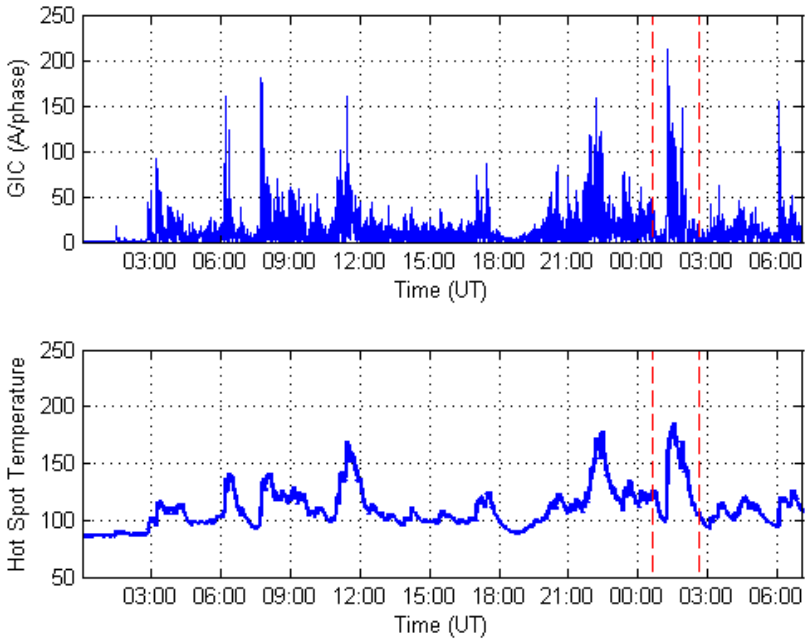


Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature $\theta(t)$ Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

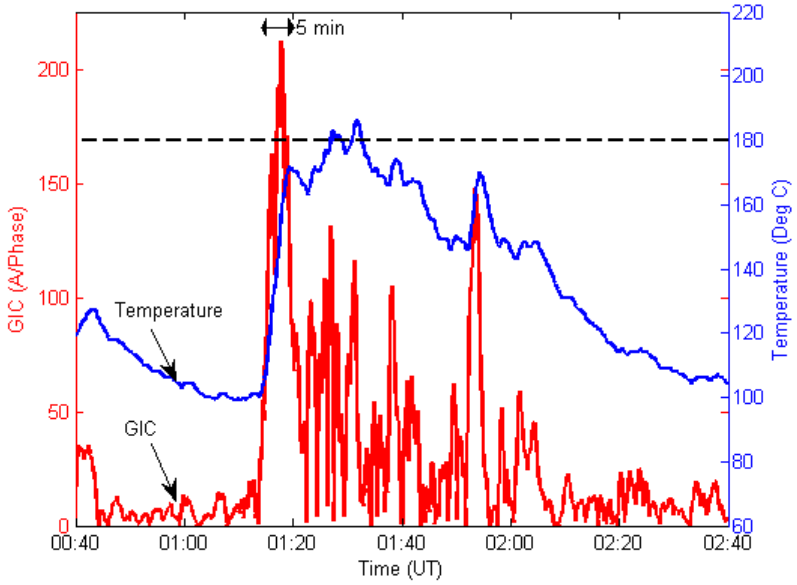


Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std C57.91 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.

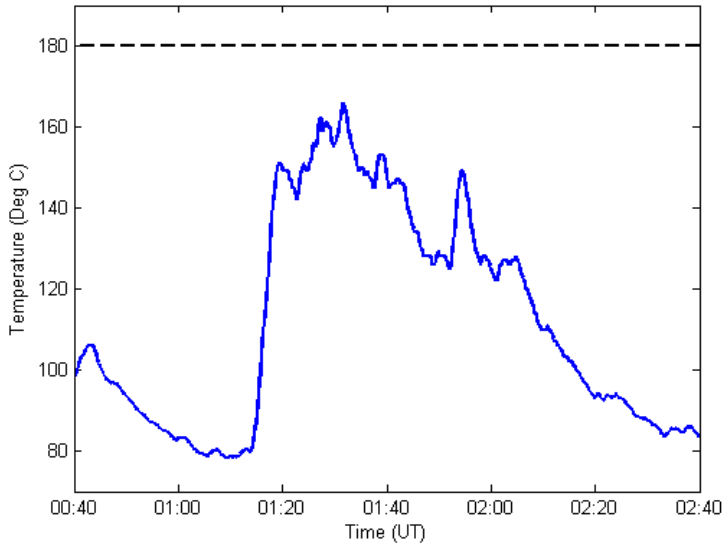


Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

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).

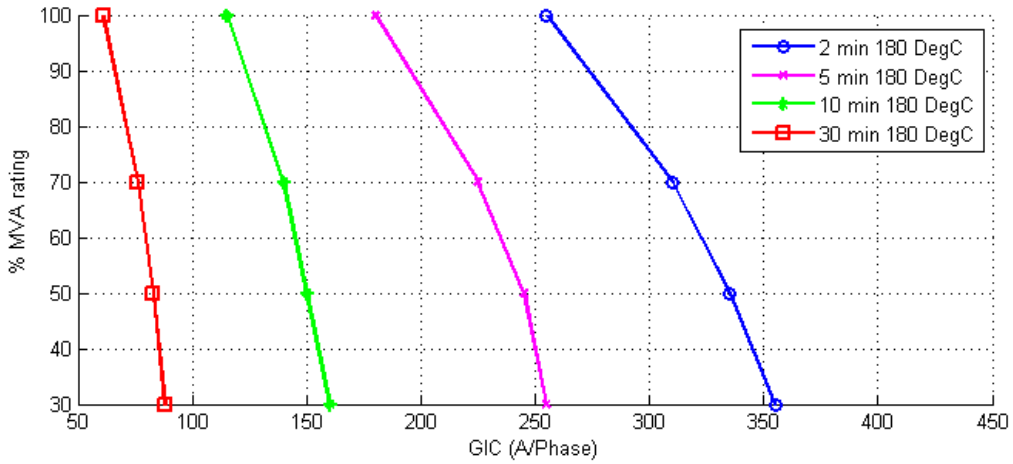


Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

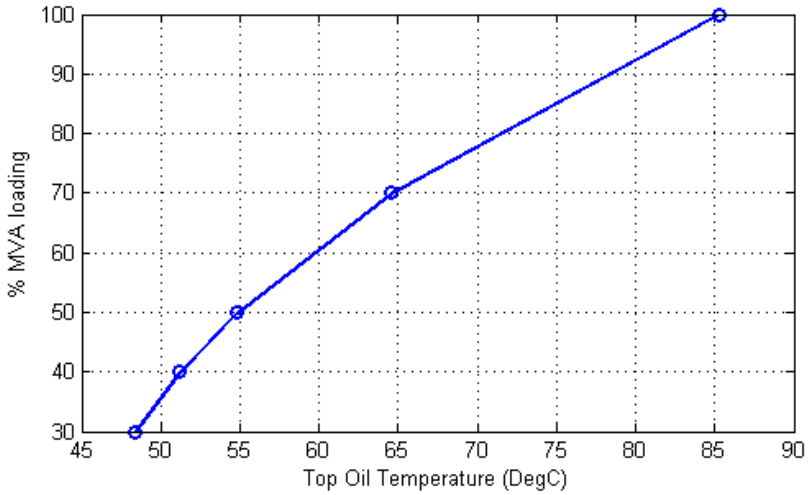


Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

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 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.

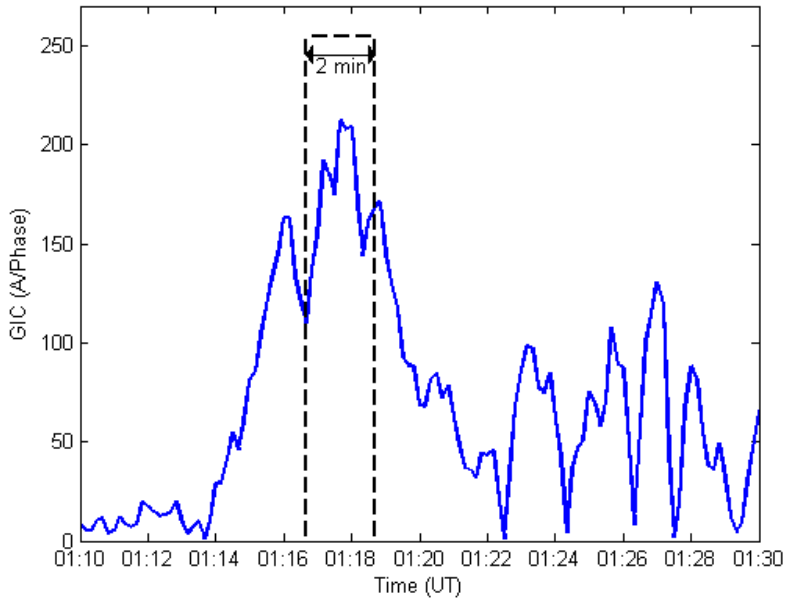


Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

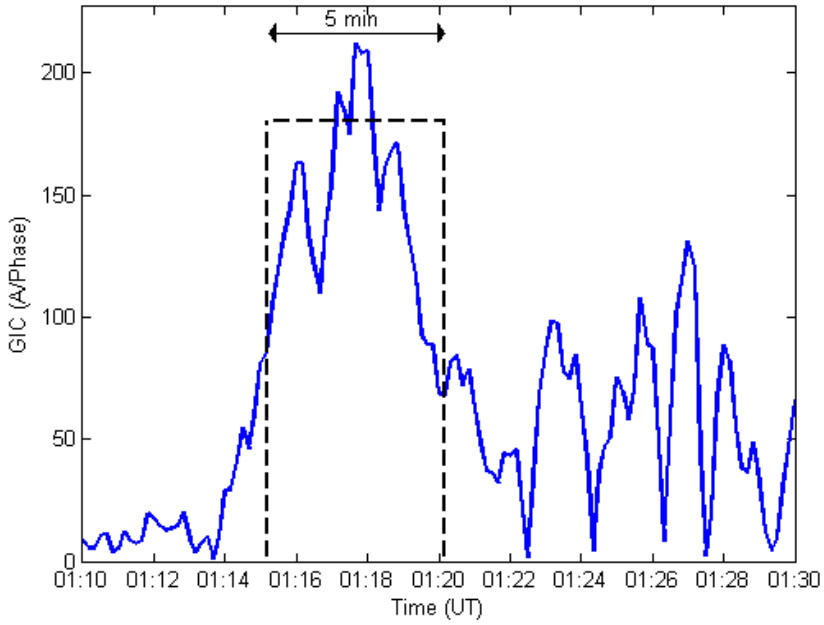


Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

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 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.

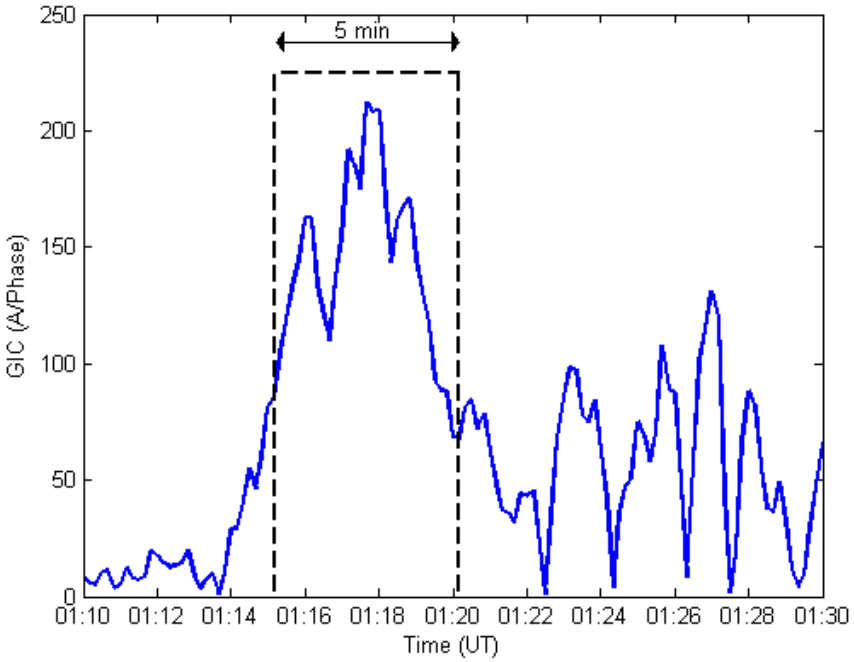


Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

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] 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] 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] Benchmark Geomagnetic Disturbance Event Description white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

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[6] 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] "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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transformer Thermal Impact Assessment White Paper

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 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.

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.

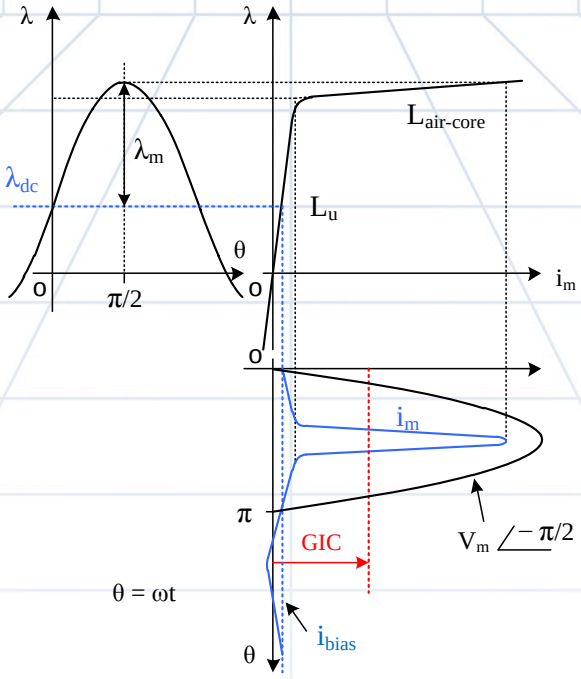


Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

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] for hot spot heating during short-term emergency operation. 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 "waveshape" 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 2 from the "Screening Criterion for Transformer Thermal Impact Assessment" white paper [7]. This table, shown as Table 1 below, provides the peak metallic hot spot temperatures that can be reached using conservative ~~screening~~ thermal models. To use Table 1, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after 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.

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	~~140~~100	~~172~~182
10	~~106~~107	~~150~~110	~~180~~186
20	~~116~~128	~~160~~120	~~187~~190
30	~~125~~139	~~170~~130	~~194~~193
40	~~132~~148	~~180~~140	~~200~~204
50	~~138~~157	~~190~~150	~~208~~213
60	~~143~~169	~~200~~160	~~214~~221
70	~~147~~170	~~210~~170	~~221~~230
75	~~150~~172	~~220~~180	~~224~~234
80	~~152~~175	~~230~~190	~~228~~241
90	~~156~~179	~~240~~200	~~233~~247
~~100~~	~~159~~	~~250~~	~~239~~
~~110~~	~~163~~	~~260~~	~~245~~
~~120~~	~~165~~	~~270~~	~~251~~
~~130~~	~~168~~	~~280~~	~~257~~

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. All thermal assessment methods should be demonstrably equivalent to assessments that use the benchmark GMD event.

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 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. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC waveshape 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.

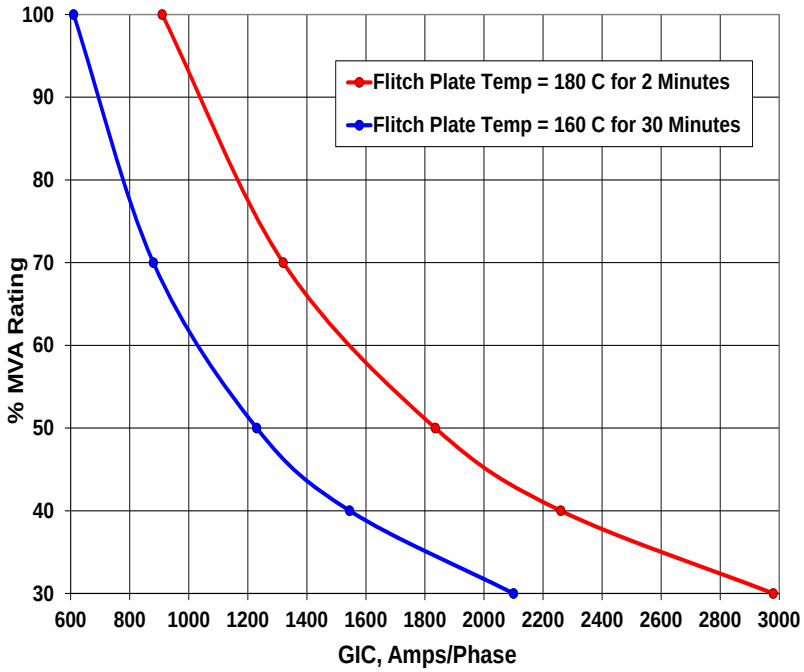


Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[1]. The input to this type of simulation is the time series or waveshape 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] 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]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[1] Technical details of this methodology can be found in [4].

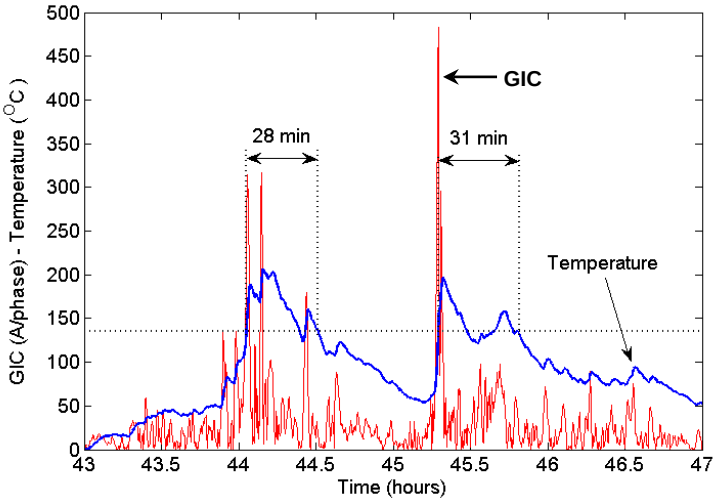


Figure 3: Sample Tie Plate Temperature Calculation
Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" 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 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].

$$GIC(t) = \left|E(t)\right| \cdot \left\{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\right\} \quad (2)$$

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/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] after the appropriate geomagnetic latitude scaling factor α is applied[2]. 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 conductivity scaling factor β[3]. 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]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)} \quad (6)$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)} \quad (7)$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

[2] 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.

[3] 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.

It should be emphasized that even for the same reference event, the GIC(t) waveshape 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 to test all transformers is incorrect.

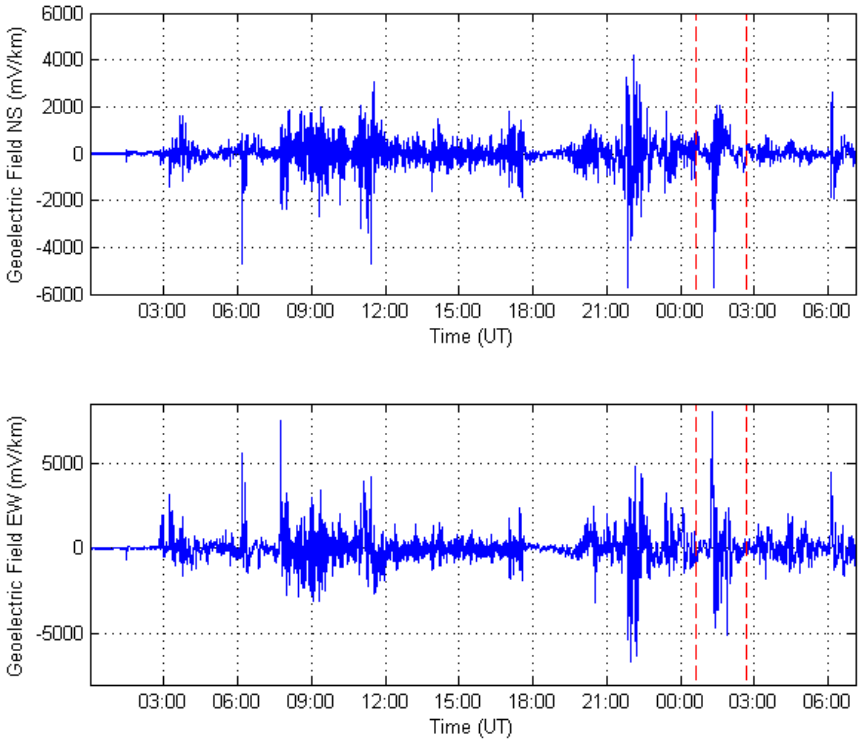


Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

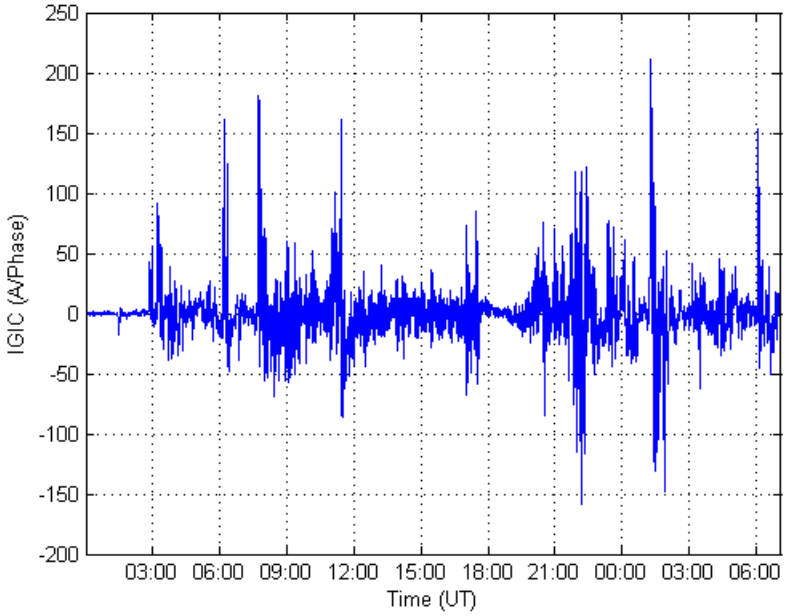


Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

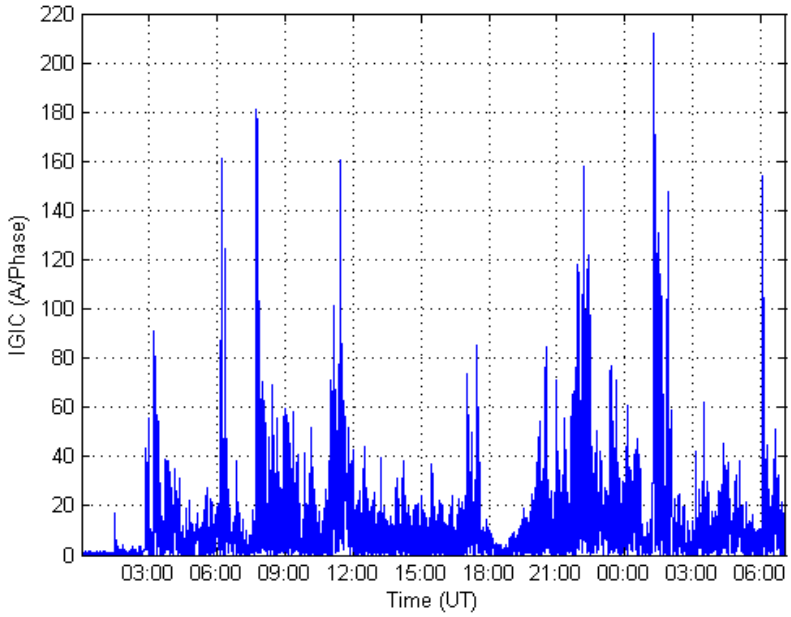


Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

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] 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.[4]

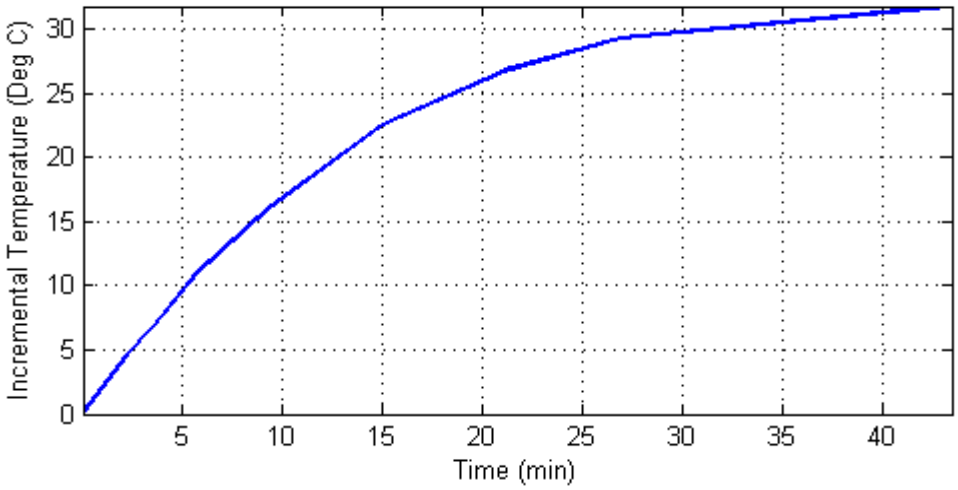


Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step
Metallic hot spot heating.

[4] 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.

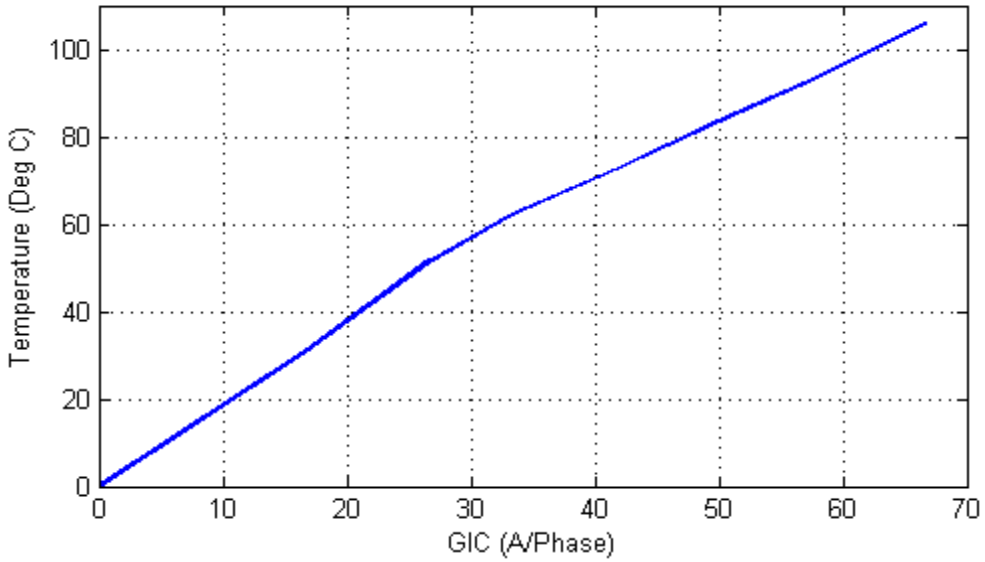


Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

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.

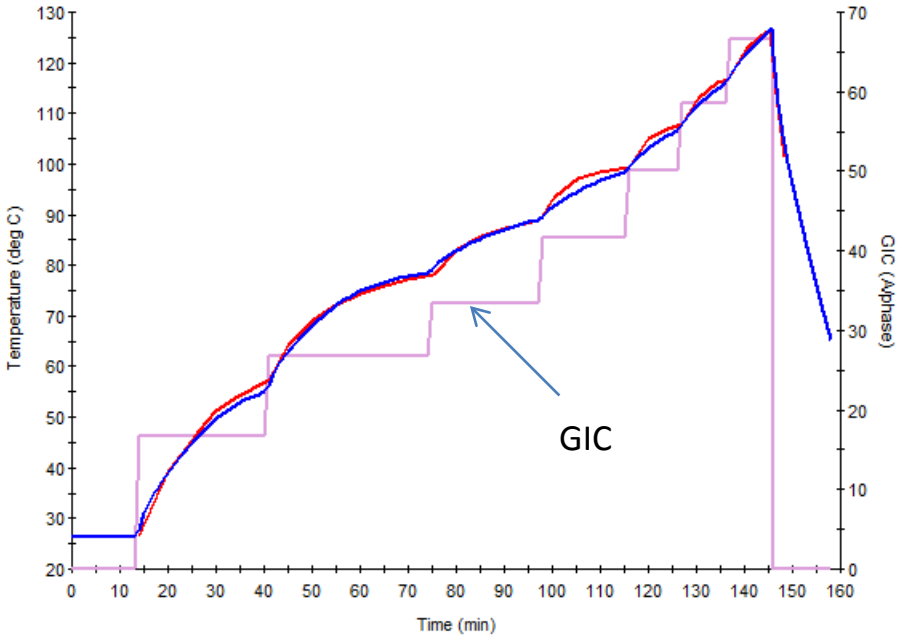


Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). Injected current is represented by the magenta trace.

To obtain the thermal response of the transformer to a GIC waveshape 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 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. 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 hot spot temperature time series $\theta(t)$. **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

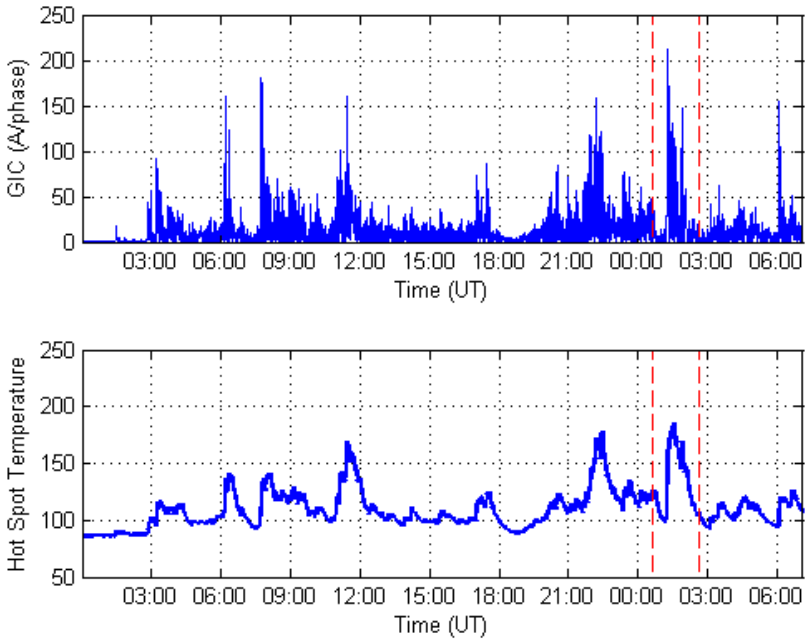


Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature $\theta(t)$ Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

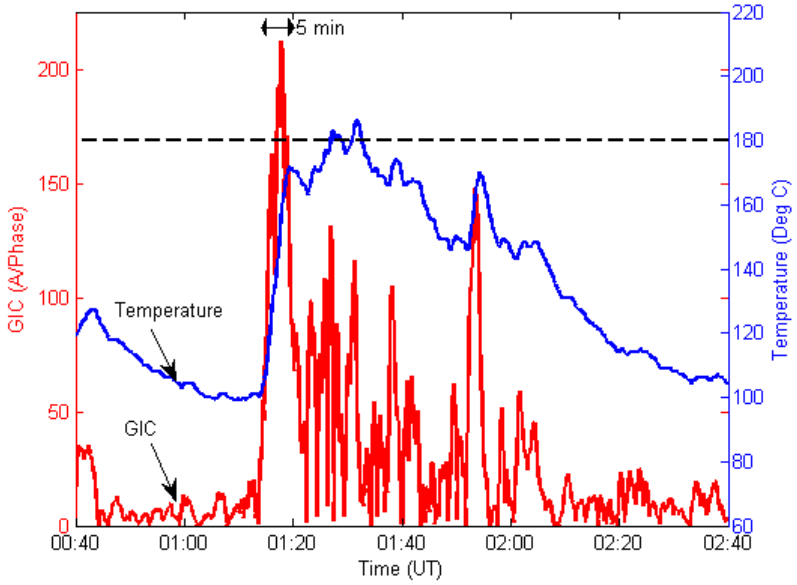


Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std C57.91 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.

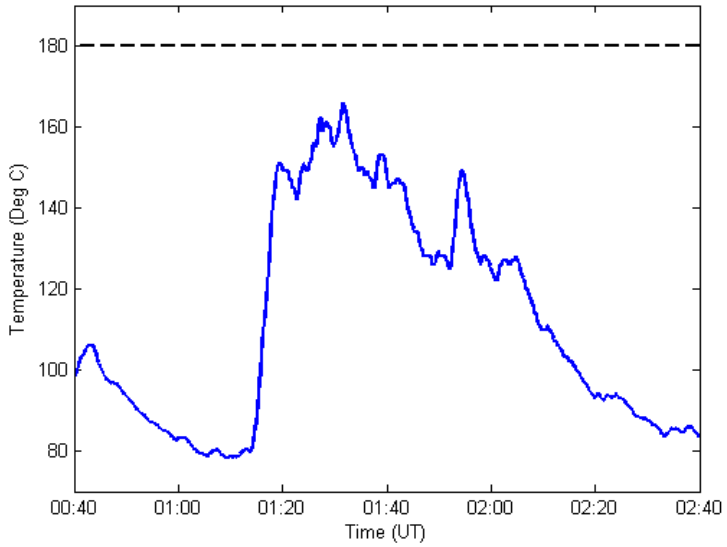


Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

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 ~~13~~ 14** (calculated using formulas from IEEE Std C57.91).

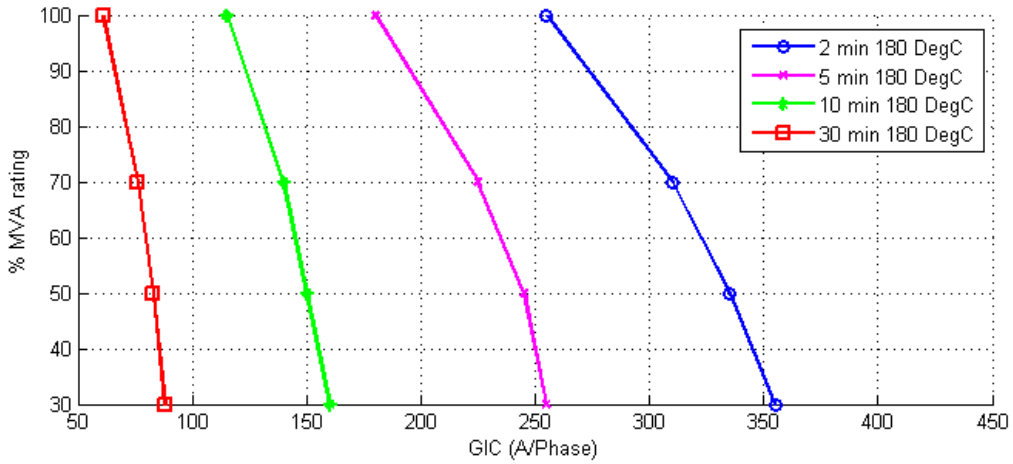


Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

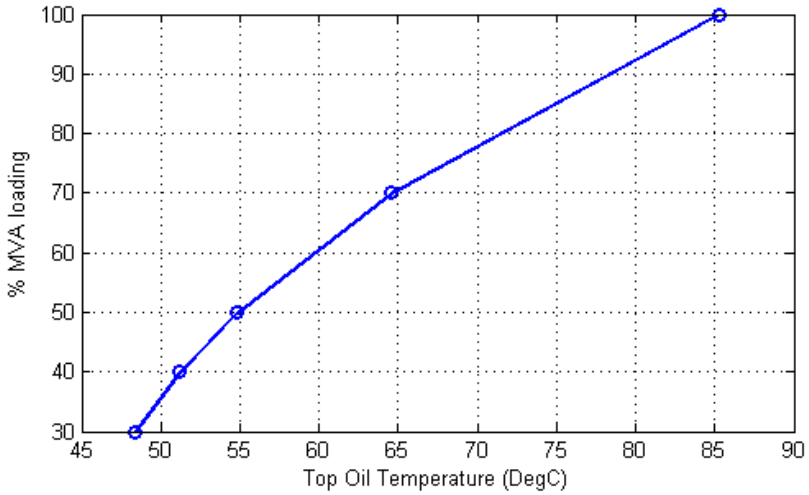


Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

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 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.

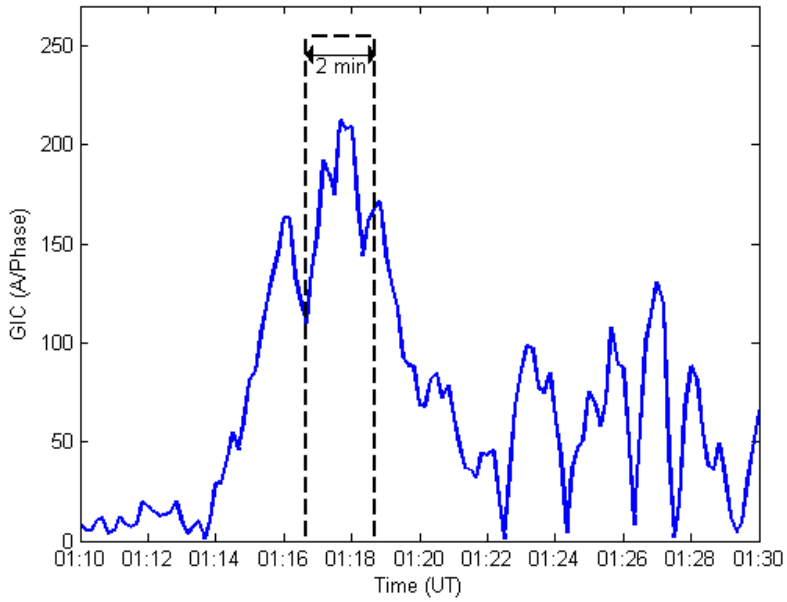


Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

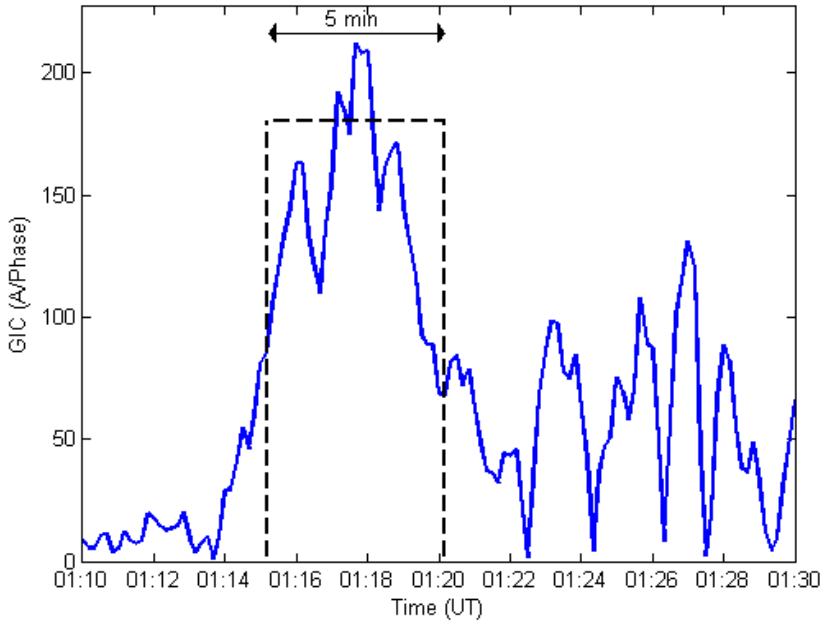


Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

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 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.

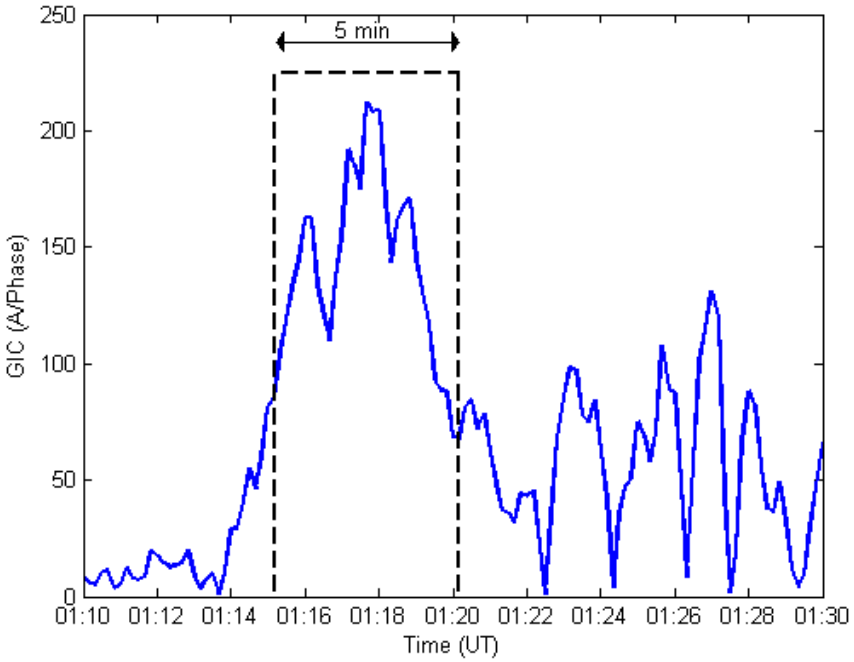


Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

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[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] 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] 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] 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/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] 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] "Screening Criterion for Transformer Thermal Impact Assessment". ~~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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Screening Criterion for Transformer Thermal Impact Assessment

Project 2013-03 (Geomagnetic Disturbance Mitigation)

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

Summary

Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. The standard requires transformer thermal impact assessments to be performed on power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. Transformers are exempt from the thermal impact assessment requirement if the maximum effective geomagnetically-induced current (GIC) in the transformer is less than 75 A per phase as determined by GIC analysis of the system. Based on published power transformer measurement data as described below, an effective GIC of 75 A per phase is a conservative screening criterion. To provide an added measure of conservatism, the 75 A per phase threshold, although derived from measurements in single-phase units, is applicable to transformers with all core types (e.g., three-limb, three-phase).

Justification

Applicable entities are required to carry out a thermal assessment with GIC(t) calculated using the benchmark GMD event geomagnetic field time series or waveshape for effective GIC values above a screening threshold. The calculated GIC(t) for every transformer will be different because the length and orientation of transmission circuits connected to each transformer will be different even if the geoelectric field is assumed to be uniform. However, for a given thermal model and maximum effective GIC there are upper and lower bounds for the peak hot spot temperatures. These are shown in **Figure 1** using three available thermal models based on direct temperature measurements.

The results shown in **Figure 1** summarize the peak metallic hot spot temperatures when GIC(t) is calculated using (1), and systematically varying GIC_E and GIC_N to account for all possible orientation of circuits connected to a transformer. The transformer GIC (in A/phase) for any value of E_E (t) and E_N(t) can be calculated using equation (1) from reference [1].

$$GIC(t) = \left|E(t)\right| \cdot \left\{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\right\} \quad (1)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \tag{2}$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \tag{3}$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \tag{4}$$

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/V/km.

It should be emphasized that with the thermal models used and the benchmark GMD event geomagnetic field waveshape, peak hot spot temperatures must lie below the envelope shown in **Figure 1**. The x-axis in Figure 1 corresponds to the absolute value of peak GIC(t). Effective maximum GIC for a transformer corresponds to a worst-case geoelectric field orientation, which is network-specific. Figure 1 represents a possible range, not the specific thermal response for a given effective GIC and orientation.

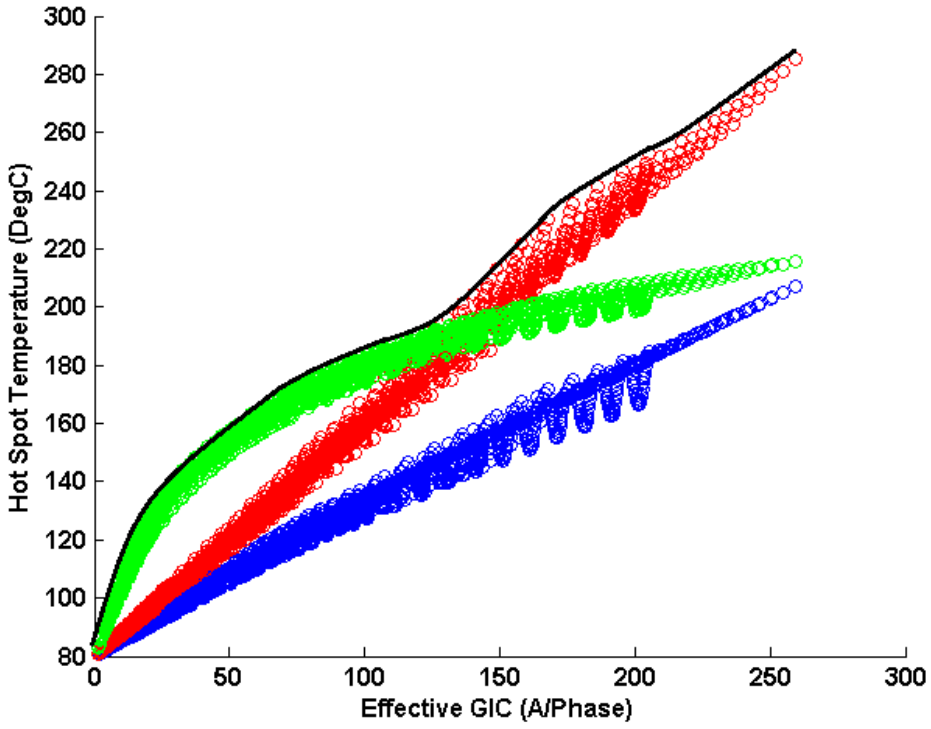


Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: SVC coupling transformer model [2]. Blue: Fingrid model [3]. Green: Autotransformer model [4].

Consequently, with the most conservative thermal models known at this point in time, the peak metallic hot spot temperature obtained with the benchmark GMD event waveshape assuming an effective GIC magnitude of 75 A per phase will result in a peak temperature between 160°C and 172°C when the bulk oil temperature is 80°C (full load bulk oil temperature). The upper boundary of 172°C remains well below the metallic hot spot 200°C threshold for short-time emergency loading suggested in IEEE Std C57.91-2011 [5] (see Table 1).

TABLE 1:
Excerpt from Maximum Temperature Limits Suggested in IEEE C57.91-2011

	Normal life expectancy loading	Planned loading beyond nameplate rating	Long-time emergency loading	Short-time emergency loading
Insulated conductor hottest-spot temperature °C	120	130	140	180
Other metallic hot-spot temperature (in contact and not in contact with insulation), °C	140	150	160	200
Top-oil temperature °C	105	110	110	110

The selection of the 75 A per phase screening threshold is based on the following considerations:

- A thermal assessment using the most conservative thermal models known to date will not result in peak hot spot temperatures above 172°C. Transformer thermal assessments should not be required by Reliability Standards when results will fall well below IEEE Std C57.91-2011 limits.
- Applicable entities may choose to carry out a thermal assessment when the effective GIC is below 75 A per phase to take into account the age or condition of specific transformers where IEEE Std C57.91- 2011 limits could be assumed to be lower than 200°C.
- The models used to determine the 75 A per phase screening threshold are known to be conservative at higher values of effective GIC, especially the SVC coupling transformer model in [2].
- Thermal models in peer-reviewed technical literature, especially those calculated models without experimental validation, are less conservative than the models used to determine the screening threshold. Therefore, a technically-justified thermal assessment for effective GIC below 75 A per phase using the benchmark GMD event geomagnetic field waveshape will always result in a "pass" on the basis of the state of the knowledge at this point in time.
- Based on simulations, the 75 A per phase screening threshold will result in a maximum instantaneous peak hot spot temperature of 172°C. However, IEEE Std C57.91- 2011 limits assume short term emergency operation (typically 30 minutes). As illustrated in **Figure 2**, simulations of the 75 A per phase screening threshold result in 30-minute duration hot spot temperatures of about

155°C. The threshold provides an added measure of conservatism in not taking into account the duration of hot spot temperatures.

- The models used in the determination of the threshold are conservative but technically justified.
- Winding hot spots are not the limiting factor in terms of hot spots due to half-cycle saturation, therefore the screening criterion is focused on metallic part hot spots only.

The 75 A per phase screening threshold was determined using single-phase transformers, but is applicable to all types of transformer construction. While it is known that some transformer types such as three-limb, three-phase transformers are intrinsically less susceptible to GIC, it is not known by how much, on the basis of experimentally-supported models.

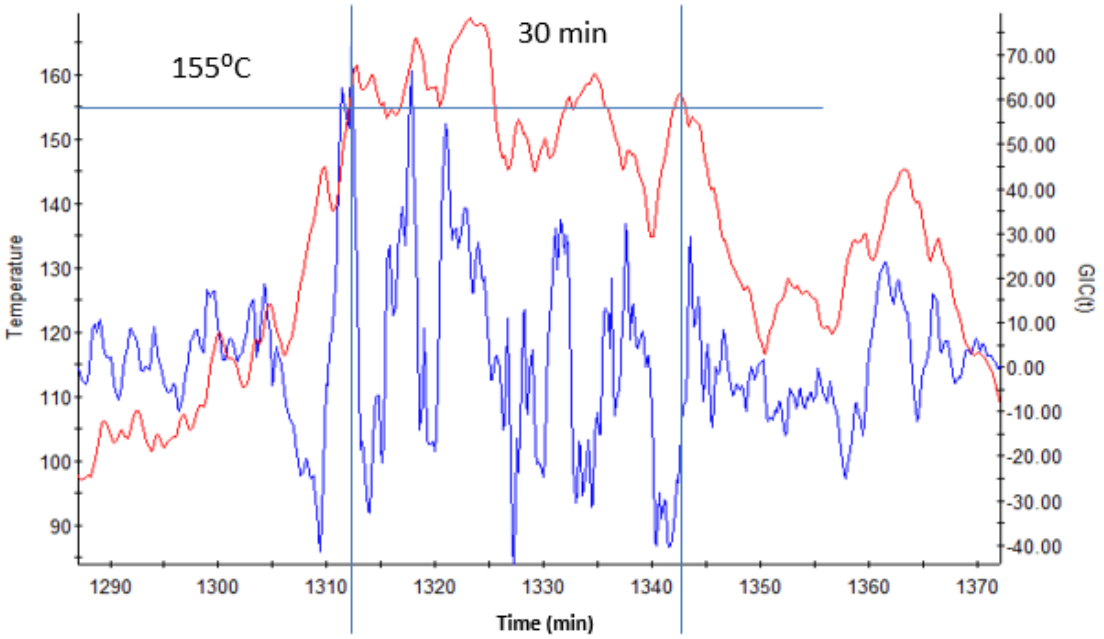


Figure 2: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: metallic hot spot temperature. Blue: GIC(t) that produces the maximum hot spot temperature with peak GIC(t) scaled to 75 A/phase.

Appendix

The envelope used for thermal screening (Figure 1) is derived from two thermal models. The first is based on laboratory measurements carried out on 500/16.5 kV 400 MVA single-phase Static Var Compensator (SVC) coupling transformer [2]. Temperature measurements were carried out at relatively small values of GIC (see **Figure 3**). The asymptotic thermal response for this model is the linear extrapolation of the known measurement values. Although the near-linear behavior of the asymptotic thermal response is consistent with the measurements made on a Fingrid 400 kV 400 MVA five-leg core-type fully-wound transformer [3] (see **Figures 4 and 5**), the extrapolation from low values of GIC is very conservative, but reasonable for screening purposes.

The second transformer model is based on a combination of measurements and modeling for a 400 kV 400 MVA single-phase core-type autotransformer [4] (see **Figures 6 and 7**). The asymptotic thermal behavior of this transformer shows a "down-turn" at high values of GIC as the tie plate increasingly saturates but relatively high temperatures for lower values of GIC. The hot spot temperatures are higher than for the two other models for GIC less than 125 A per phase.

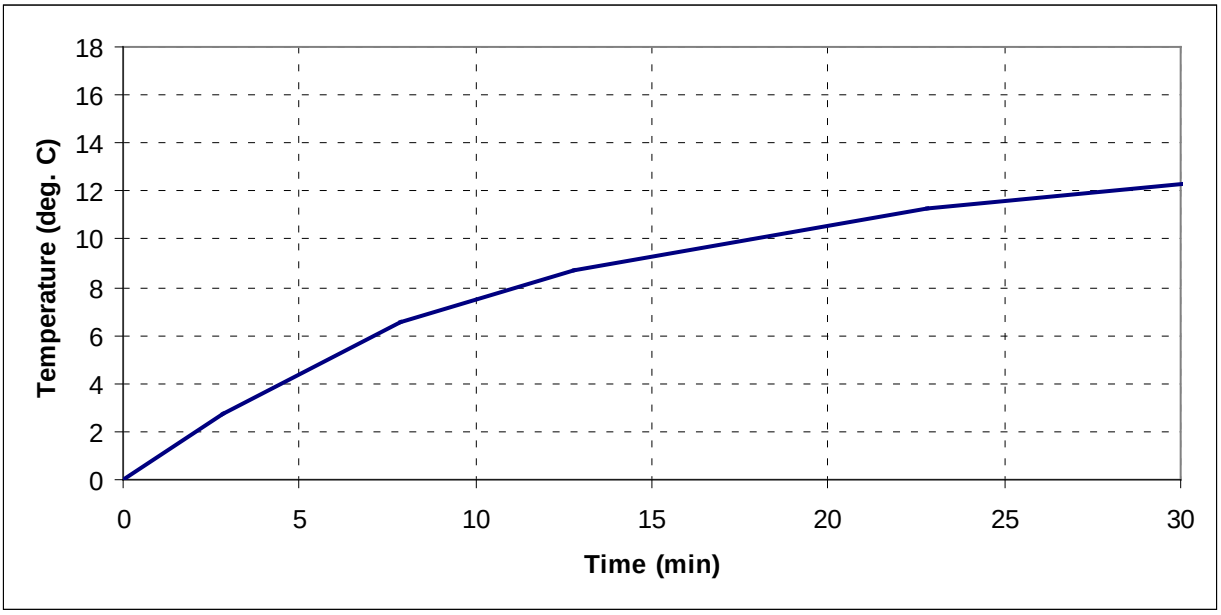


Figure 3: Thermal step response of the tie plate of a 500 kV 400 MVA single-phase SVC coupling transformer to a 5 A per phase dc step.

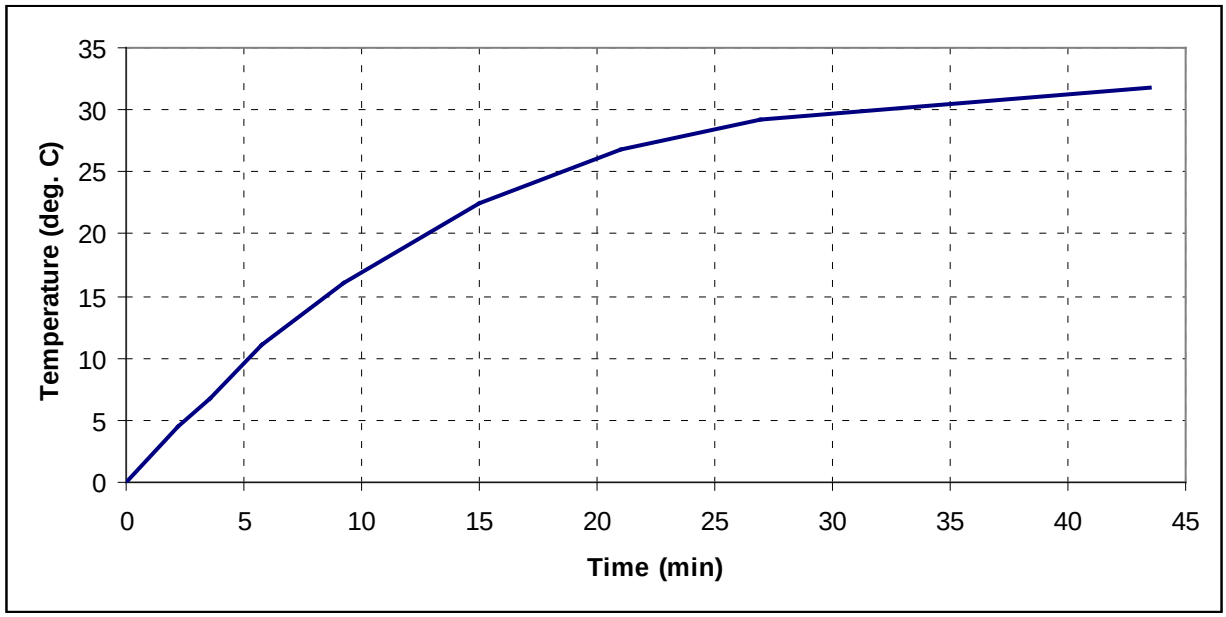


Figure 4: Step thermal response of the top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer to a 16.67 A per phase dc step.

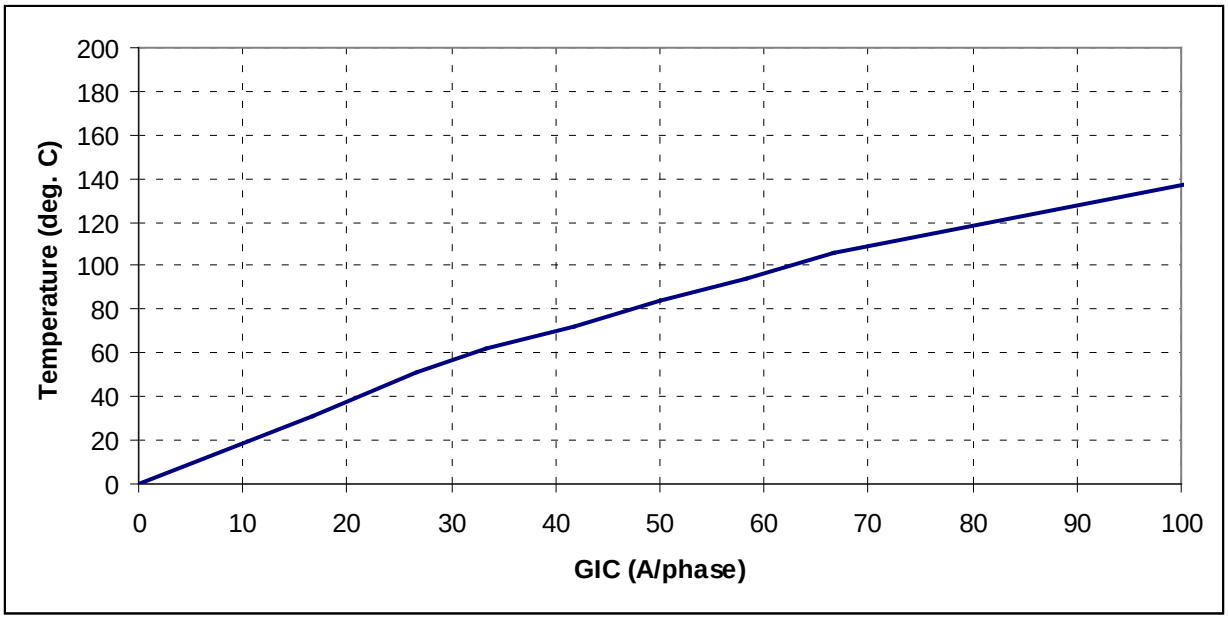


Figure 5: Asymptotic thermal response of the top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer.

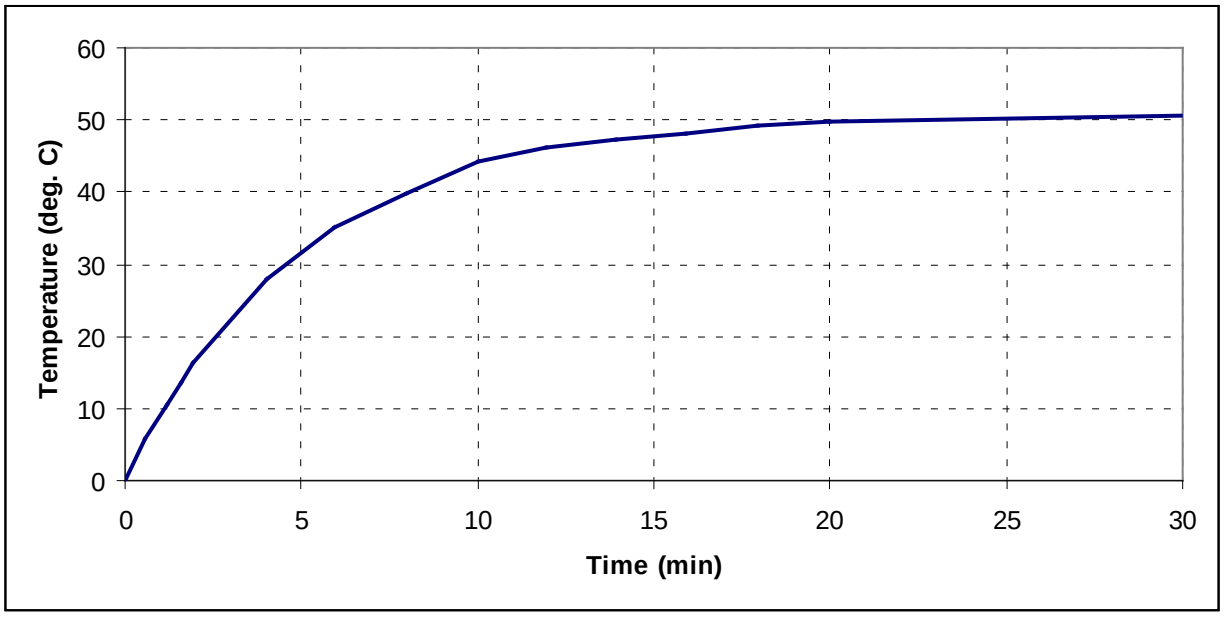


Figure 6: Step thermal response of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer to a 10 A per phase dc step.

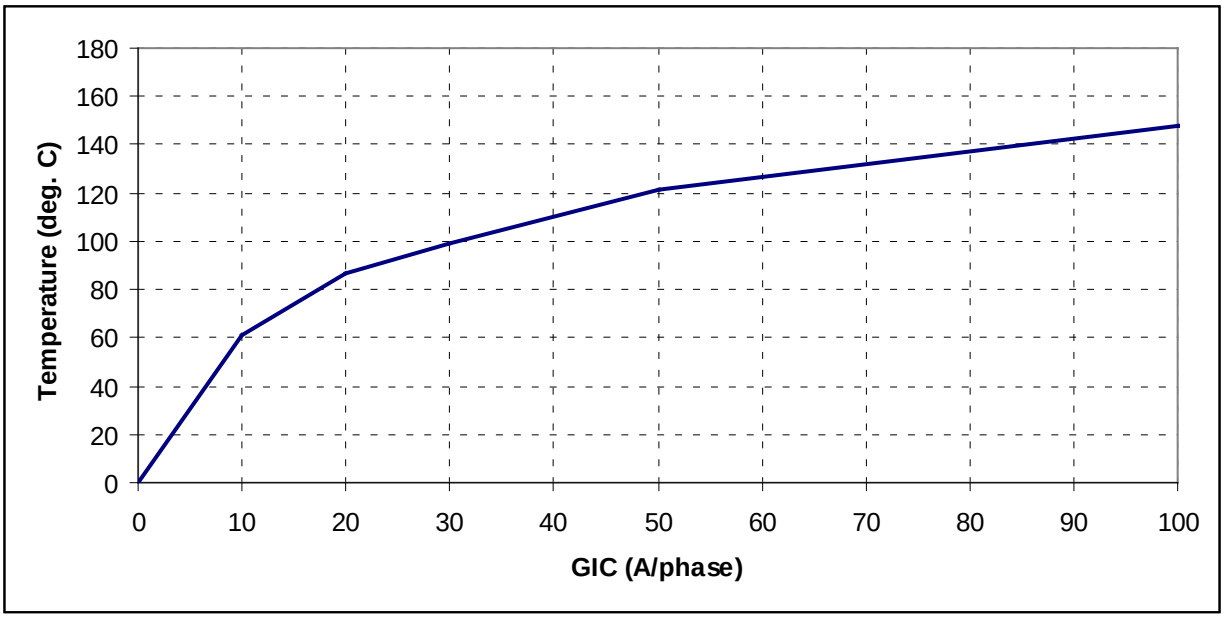


Figure 7: Asymptotic thermal response of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer.

The envelope in **Figure 1** can be used as a conservative thermal assessment for effective GIC values of 75 A per phase and greater (see Table 2).

Table 2: 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

For instance, if effective GIC is 130 A per phase and oil temperature is assumed to be 80°C, peak hot spot temperature is 193°C. This value is below the 200°C IEEE Std C57.91-2011 threshold for short time emergency loading and this transformer will have passed the thermal assessment. If the full heat run oil temperature is 67°C at maximum ambient temperature, then 150 A per phase of effective GIC translates into a peak hot spot temperature of 200°C and the transformer will have passed. If the limit is lowered to 180°C to account for the condition of the transformer, then this would be an indication to "sharpen the pencil" and perform a detailed assessment. Some methods are described in Reference [1].

The temperature envelope in Figure 1 corresponds to the values of effective GIC that result in the highest temperature for the benchmark GMD event. Different values of effective GIC could result in lower temperatures using the same model. For instance, the difference in upper and lower bounds of peak temperatures for the SVC coupling transformer model for 150 A per phase is approximately 30°C. In this case, GIC(t) should be generated to calculate the peak temperatures for the actual configuration of the transformer within the system as described in Reference [1]. Alternatively, a more precise thermal assessment could be carried out with a thermal model that more closely represents the thermal behavior of the transformer under consideration.

References

[1] Transformer Thermal Impact Assessment 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

[2] 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, Jan. 2013.

[3] 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.

[4] J. Raith, S. Ausserhofer: "GIC Strength verification of Power Transformers in a High Voltage Laboratory", GIC Workshop, Cape Town, April 2014

[5] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

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Screening Criterion for Transformer Thermal Impact Assessment

Project 2013-03 (Geomagnetic Disturbance Mitigation)

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

Summary

Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. The standard requires transformer thermal impact assessments to be performed on power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. Transformers are exempt from the thermal impact assessment requirement if the maximum effective geomagnetically-induced current (GIC) in the transformer is less than 75 A per phase as determined by GIC analysis of the system. Based on published power transformer measurement data as described below, an effective GIC of 75 A per phase is a conservative screening criterion. To provide an added measure of conservatism, the 75 A per phase threshold, although derived from measurements in single-phase units, is applicable to transformers with all core types (e.g., three-limb, three-phase).

Justification

Applicable entities are required to carry out a thermal assessment with GIC(t) calculated using the benchmark GMD event geomagnetic field time series or waveshape for effective GIC values above a screening threshold. The calculated GIC(t) for every transformer will be different because the length and orientation of transmission circuits connected to each transformer will be different even if the geoelectric field is assumed to be uniform. However, for a given thermal model and maximum effective GIC there are upper and lower bounds for the peak hot spot temperatures. These are shown in **Figure 1** using three available thermal models based on direct temperature measurements.

The results shown in **Figure 1** summarize the peak metallic hot spot temperatures when GIC(t) is calculated using (1), and systematically varying GIC_E and GIC_N to account for all possible orientation of circuits connected to a transformer. The transformer GIC (in A/phase) for any value of E_E (t) and E_N(t) can be calculated using equation (1) from reference [1].

$$GIC(t) = \left|E(t)\right| \cdot \left\{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\right\} \quad (1)$$

where

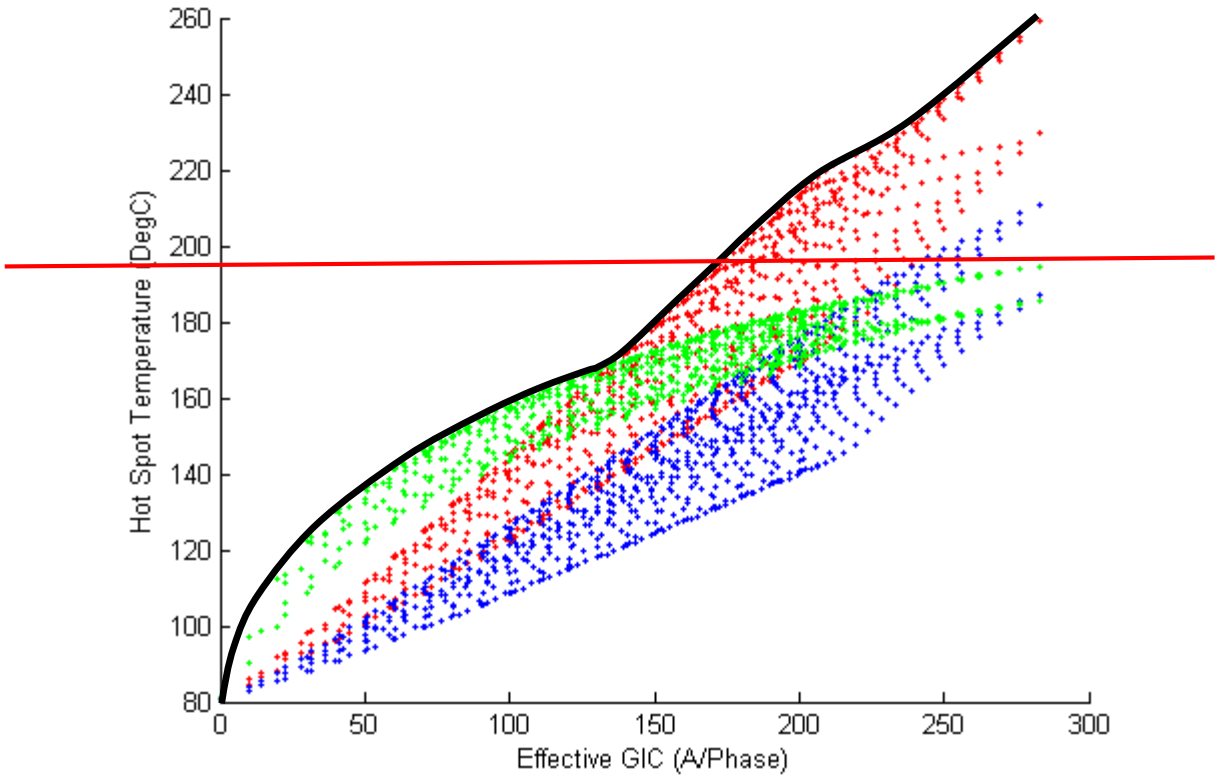
$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \quad (2)$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \quad (3)$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \quad (4)$$

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/V/km.

It should be emphasized that with the thermal models used and the benchmark GMD event geomagnetic field waveshape, peak hot spot temperatures must lie below the envelope shown in **Figure 1**. The x-axis in Figure 1 corresponds to the absolute value of peak GIC(t). Effective maximum GIC for a transformer corresponds to a worst-case geoelectric field orientation, which is network-specific. Figure 1 represents a possible range, not the specific thermal response for a given effective GIC and orientation.


Hot Spot Temperature (DegC)
260
240
220
200
180
160
140
120
100
80
0
50
100
150
200
250
300
Effective GIC (A/Phase)

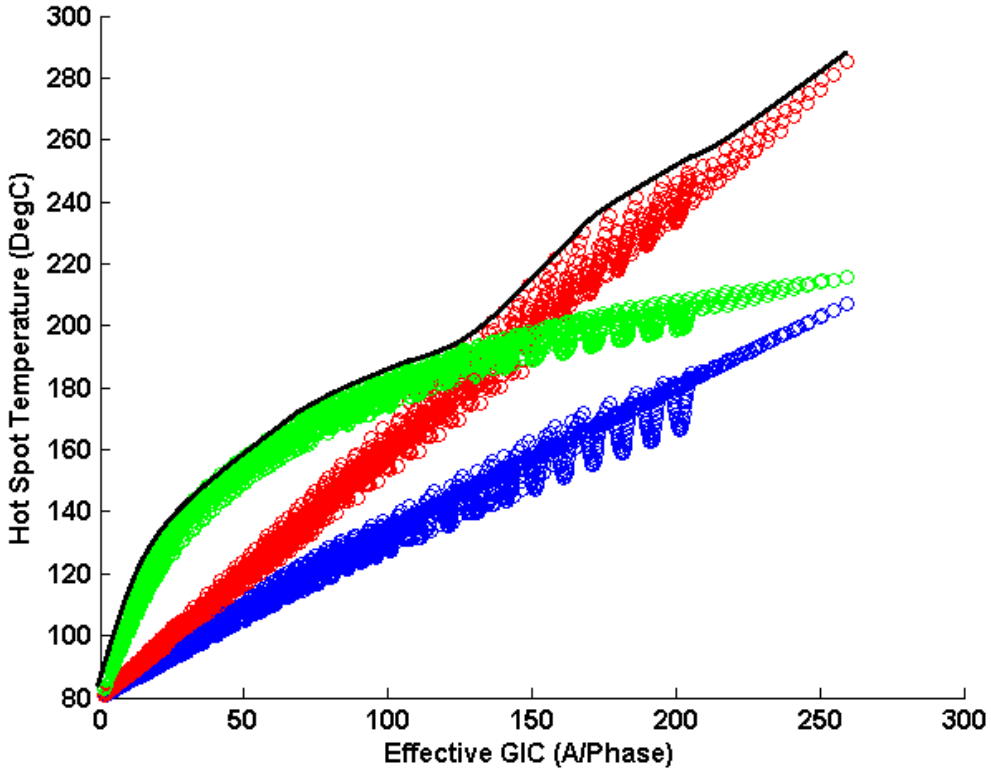


Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: ~~Screening~~SVC coupling transformer model [2]. Blue: Fingrid model [3]. Green: ~~SoCo~~Autotransformer model [4].

Consequently, with the most conservative thermal models known at this point in time, the peak metallic hot spot temperature obtained with the benchmark GMD event waveshape assuming an effective GIC magnitude of 75 A per phase will result in a peak temperature between ~~104~~160°C and ~~150~~172°C when the bulk oil temperature is 80°C (full load bulk oil temperature). The upper boundary of ~~150~~172°C ~~falls~~remains well below the metallic hot spot 200°C threshold for short-time emergency loading suggested in IEEE Std C57.91-2011 [5] (see Table 1).

TABLE 1:
Excerpt from Maximum Temperature Limits Suggested in IEEE C57.91-2011

	Normal life expectancy loading	Planned loading beyond	Long-time emergency loading	Short-time emergency loading

		nameplate rating		
Insulated conductor hottest-spot temperature °C	120	130	140	180
Other metallic hot-spot temperature (in contact and not in contact with insulation), °C	140	150	160	200
Top-oil temperature °C	105	110	110	110

The selection of the 75 A per phase screening threshold is based on the following considerations:

- A thermal assessment using the most conservative thermal models known to date will not result in peak hot spot temperatures above ~~150~~172°C. Transformer thermal assessments should not be required by Reliability Standards when results will fall well below IEEE Std C57.91-2011 limits.
- Applicable entities may choose to carry out a thermal assessment when the effective GIC is below 75 A per phase to take into account the age or condition of specific transformers where IEEE Std C57.91- 2011 limits could be assumed to be lower than 200°C.
- The models used to determine the 75 A per phase screening threshold are known to be conservative at higher values of effective GIC, especially the ~~screening~~SVC coupling transformer model in [2].
- Thermal models in peer-reviewed technical literature, especially those calculated models without experimental validation, are less conservative than the models used to determine the screening threshold. Therefore, a technically-justified thermal assessment for effective GIC below 75 A per phase using the benchmark GMD event geomagnetic field waveshape will always result in a "pass" on the basis of the state of the knowledge at this point in time.
- ~~The~~ Based on simulations, the 75 A per phase screening threshold ~~was determined on the basis of~~ will result in a maximum instantaneous peak hot spot temperature of 172°C. However, IEEE Std C57.91- 2011 limits assume short term emergency operation (typically 30 minutes). As illustrated in **Figure 2**, simulations of the 75 A per phase screening threshold result in 30-minute duration hot spot temperatures of about 155°C. The threshold provides an added measure of conservatism in not taking into account the duration of hot spot temperatures.
- The models used in the determination of the threshold are conservative but technically justified.
- Winding hot spots are not the limiting factor in terms of hot spots due to half-cycle saturation, therefore the screening criterion is focused on metallic part hot spots only.

The 75 A per phase screening threshold was determined using single-phase transformers, but is applicable to all types of transformer construction. While it is known that some transformer types such as three-limb, three-phase transformers are intrinsically less susceptible to GIC, it is not known by how much, on the basis of experimentally-supported models.

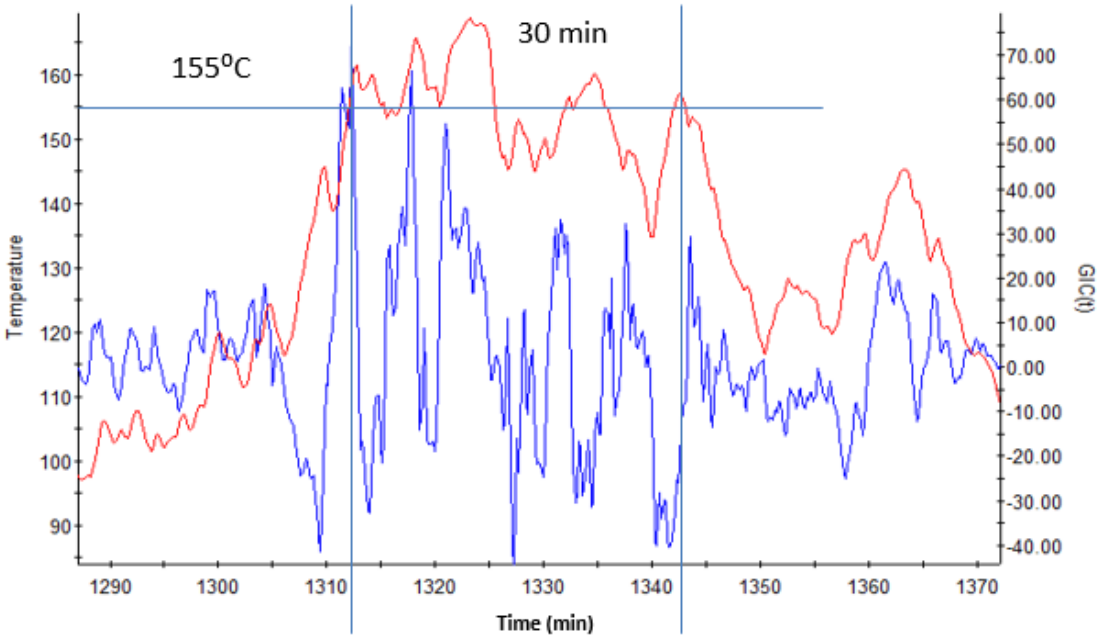


Figure 2: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: metallic hot spot temperature. Blue: GIC(t) that produces the maximum hot spot temperature with peak GIC(t) scaled to 75 A/phase.

Appendix

The envelope used for thermal screening (Figure 1) is derived from two thermal ~~model~~models. The first is based on laboratory measurements carried out on 500/16.5 kV 400 MVA single-phase Static Var Compensator (SVC) coupling transformer [2]. Temperature measurements were carried out at relatively small values of GIC (see **Figure ~~2).~~ 3**). The asymptotic thermal response for this model is the linear extrapolation of the known measurement values. Although the near-linear behavior of the asymptotic thermal response is consistent with the measurements made on a Fingrid 400 kV 400 MVA five-leg core-type fully-wound transformer [3] (see **Figures ~~3~~4 and ~~4~~5**), the extrapolation from low values of GIC is very conservative, but reasonable for screening purposes.

The ~~third~~second transformer model is based on a combination of measurements and modeling for a 400 kV 400 MVA single-phase core-type autotransformer [4] (see **Figures ~~5~~6 and ~~6~~7**). The asymptotic thermal behavior of this transformer shows a "down-turn" at high values of GIC as the tie plate increasingly saturates but relatively high temperatures for lower values of GIC. The hot spot temperatures are higher than for the two other models for GIC less than 125 A per phase.

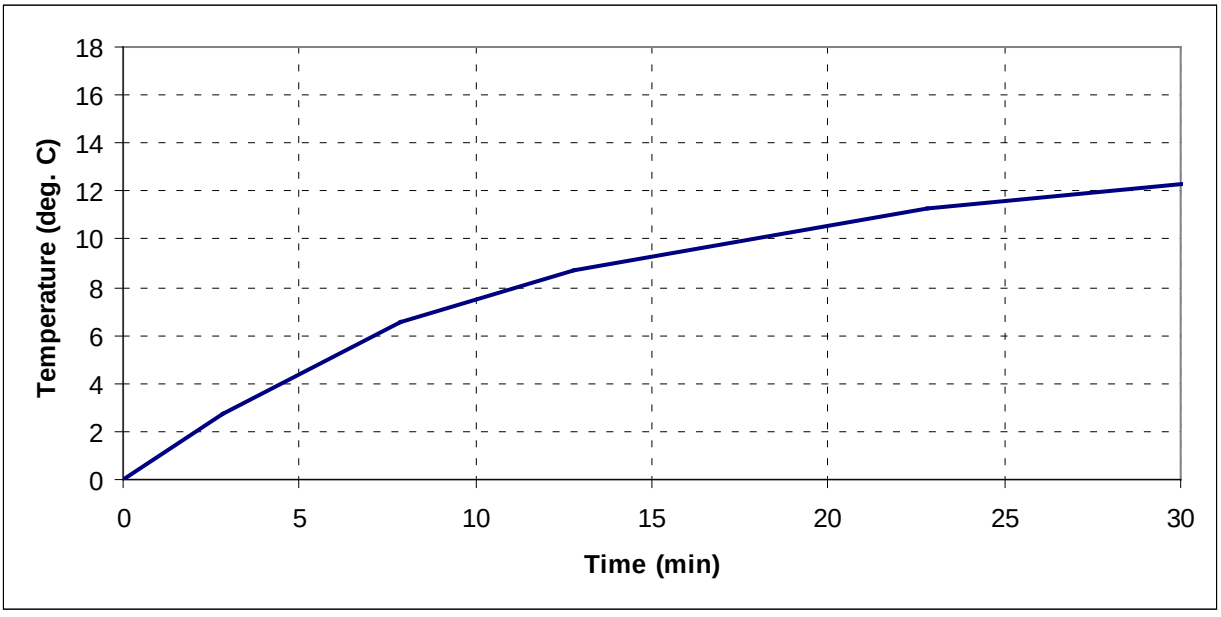


Figure ~~2~~3: Thermal step response of the tie plate of a 500 kV 400 MVA single-phase SVC coupling transformer to a 5 A per phase dc step.

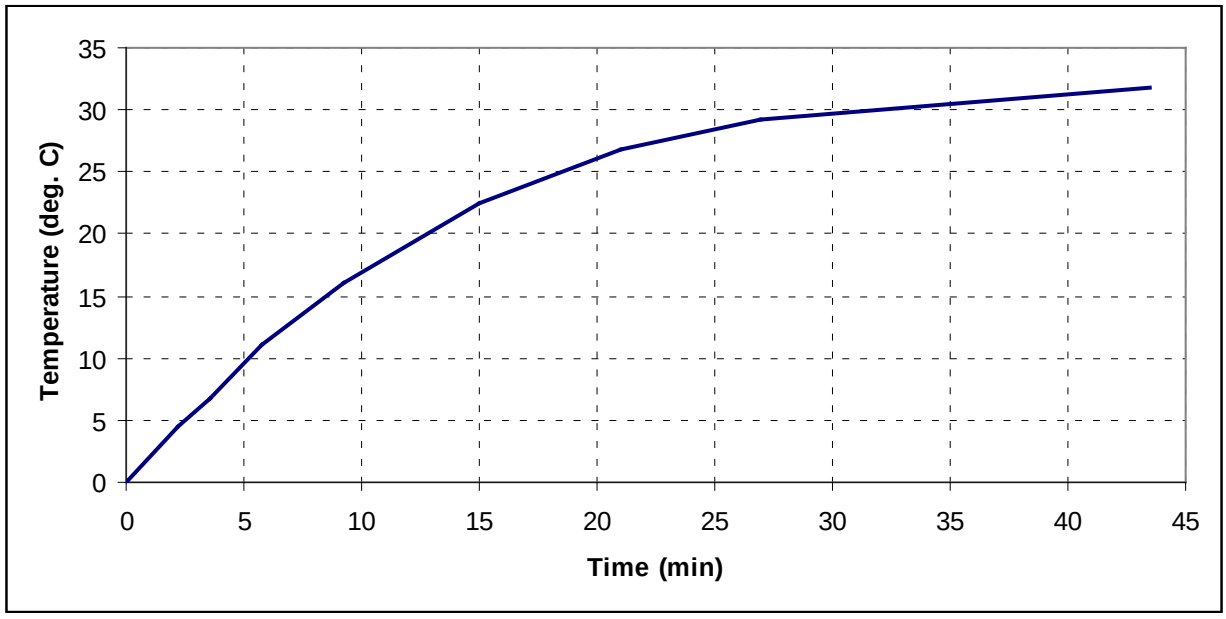


Figure ~~3~~4: Step thermal response of the ~~Flitch plate~~top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer to a ~~10~~16.67 A per phase dc step.

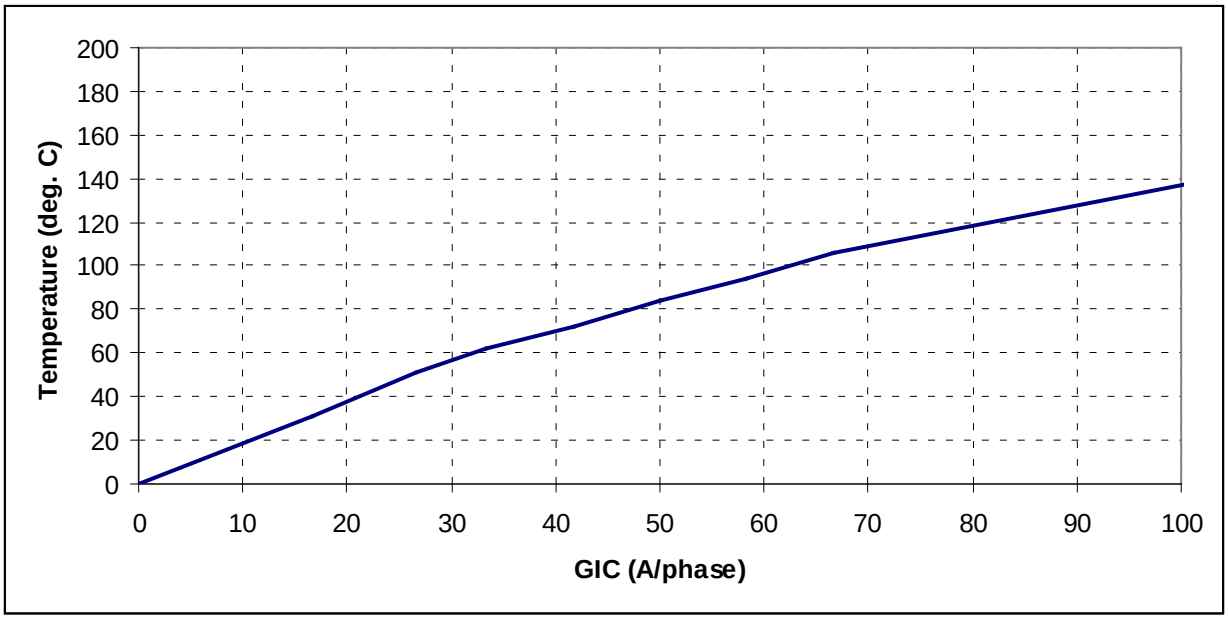


Figure ~~4~~5: Asymptotic thermal response of the ~~Flitch plate~~top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer.

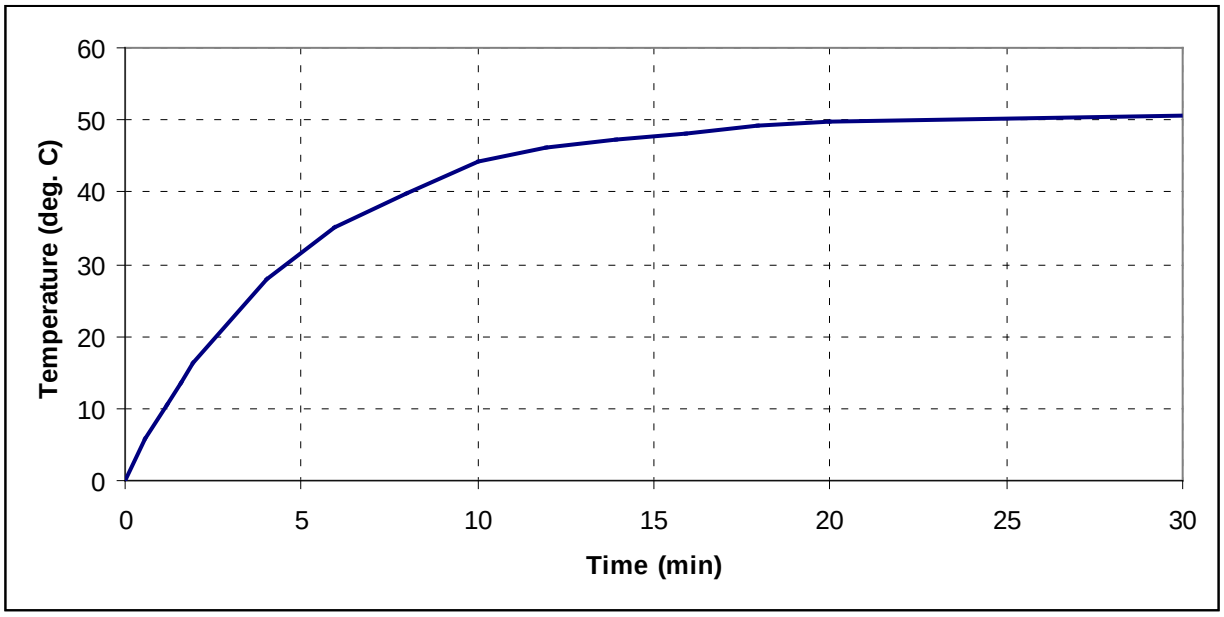


Figure ~~5~~6: Step thermal response of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer to a 10 A per phase dc step.

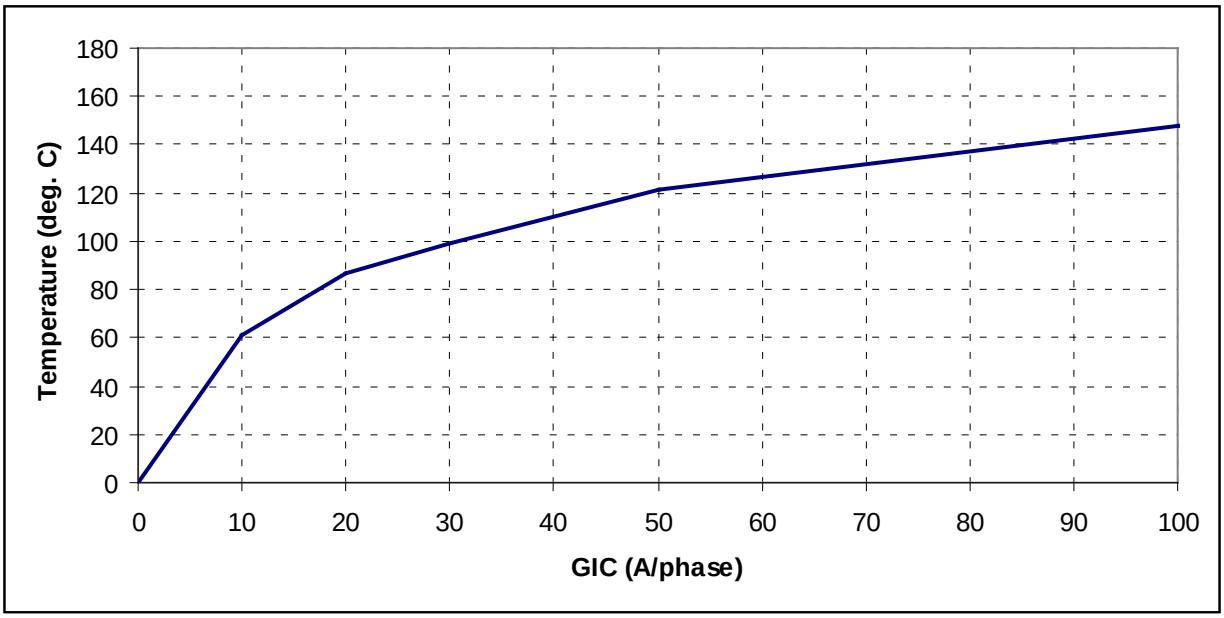


Figure ~~6~~7: Asymptotic thermal response of the ~~Flitch~~tie plate of a 400 kV 400 MVA single-phase core-type autotransformer.

The ~~composite~~ envelope in **Figure 1** can be used as a conservative thermal assessment for effective GIC values of 75 A per phase and greater (see Table 2).

Table 2: 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	~~140~~100	~~172~~182
10	~~106~~107	~~150~~110	~~180~~186
20	~~116~~128	~~160~~120	~~187~~190
30	~~125~~139	~~170~~130	~~194~~193
40	~~132~~148	~~180~~140	~~200~~204
50	~~138~~157	~~190~~150	~~208~~213
60	~~143~~169	~~200~~160	~~214~~221
70	~~147~~170	~~210~~170	~~221~~230
75	~~150~~172	~~220~~180	~~224~~234
80	~~152~~175	~~230~~190	~~228~~241
90	~~156~~179	~~240~~200	~~233~~247
~~100~~	~~159~~	~~250~~	~~239~~
~~110~~	~~163~~	~~260~~	~~245~~
~~120~~	~~165~~	~~270~~	~~251~~
~~130~~	~~168~~	~~280~~	~~257~~

For instance, if effective GIC is ~~150~~130 A per phase and oil temperature is assumed to be 80°C, peak hot spot temperature is ~~180~~193°C. This value is below the 200°C IEEE Std C57.91-2011 threshold for short time emergency loading and this transformer will have passed the thermal assessment. If the full heat run oil temperature is ~~59~~67°C at maximum ambient temperature, then ~~210~~150 A per phase of effective GIC translates ~~in~~into a peak hot spot temperature of 200°C and the transformer will have passed. If the limit is lowered to 180°C to account for the condition of the transformer, then this would be an indication to "sharpen the pencil" and perform a detailed assessment. Some methods are described in Reference [1].

The temperature envelope in Figure 1 corresponds to the values of ~~GIC_E and GIC_N~~effective GIC that result in the highest temperature for the benchmark GMD event. Different values of effective GIC could result in lower temperatures using the same ~~screening~~ model. For instance, the difference in upper and lower ~~bound~~bounds of peak temperatures for the ~~screening~~SVC coupling transformer model for ~~210~~150 A per phase is ~~165~~approximately 30°C. In this case, GIC(t) should be generated to calculate the peak temperatures for the actual configuration of the transformer within the system as described in Reference [1]. Alternatively, a more precise thermal assessment could be carried out with a thermal model that more closely represents the thermal behavior of the transformer under consideration.

References

[1] Transformer Thermal Impact Assessment 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

[2] 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, Jan. 2013.

[3] 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.

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Unofficial Comment Form

Project 2013-03 Geomagnetic Disturbance Mitigation

Do not use this form for submitting comments. Use the electronic form to submit comments on Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1 White Papers. The electronic form must be submitted by **8 p.m. Eastern, June 13, 2016.**

Documents and information about this project are available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page. If you have questions, contact Mark Olson, Senior Standards Developer (via email), or at 404.446-9760.

Background Information

On May 16, 2013 FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages. Project 2013-03 responds to the FERC directives as follows:

- Stage 1. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June, 2014.
- Stage 2. Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the proposed standard will require the applicable entity to develop corrective actions to mitigate the risk of voltage collapse, uncontrolled separation, or Cascading. The Stage 2 standard was filed for regulatory approval in January 2015. In May 2015, FERC issued a Notice of Proposed Rulemaking proposing to approve TPL-007-1 and direct NERC to develop some modifications through the standards development process. A FERC staff-led technical conference on the proposed standard was held March 1, 2016.

The standards drafting team (SDT) identified an error in Figure 1 of the *Screening Criterion for Transformer Thermal Impact Assessment* white paper (Screening Criterion white paper). The error resulted in incorrect plotting of simulated power transformer peak hot-spot heating from the Benchmark GMD Event. The SDT has corrected Figure 1 and revised related sections in the Screening Criterion white paper. The SDT has also made related revisions to other Project 2013-03 white papers. The revisions do not affect requirements in proposed TPL-007-1 but are being incorporated into the project white papers to maintain accuracy.

Questions

1. The SDT has corrected Figure 1 and revised related sections in the Screening Criterion white paper. The SDT has also made related revisions to other Project 2013-03 white papers. Do you agree with the revisions? If not, please provide specific recommendation(s) and technical justification.

   ☐ Yes
   ☐ No

   Comments:

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation Revised White Papers

Comment Period Open through June 13, 2016

Now Available

A comment period is open for **Project 2013-03 Geomagnetic Disturbance Mitigation** revised white papers. Stakeholders may provide comments using the link below through **8 p.m. Eastern, Monday, June 13, 2016.**

The standards drafting team (SDT) identified an error in Figure 1 of the *Screening Criterion for Transformer Thermal Impact Assessment* white paper (Screening Criterion white paper). The error resulted in incorrect plotting of simulated power transformer peak hot-spot heating from the Benchmark GMD Event. The SDT has corrected Figure 1 and revised related sections in the Screening Criterion white paper. The SDT has also made related revisions to other Project 2013-03 white papers. The revisions do not affect requirements in proposed TPL-007-1 but are being incorporated into the project white papers to maintain accuracy.

Commenting

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

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email) or by phone at (404) 446-9760.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2013-03 Geomagnetic Disturbance Mitigation White Papers
Comment Period Start Date:	5/12/2016
Comment Period End Date:	6/13/2016
Associated Ballots:	

There were 14 sets of responses, including comments from approximately 14 different people from approximately 14 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT has corrected Figure 1 and revised related sections in the Screening Criterion white paper. The SDT has also made related revisions to other Project 2013-03 white papers. Do you agree with the revisions? If not, please provide specific recommendation(s) and technical justification.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
					Chip Koloini	Golden Spread Electric Cooperative, Inc.	5	SPP RE
					Ellen Watkins	Sunflower Electric Power Corporation	1	SPP RE
					Ryan Strom	Buckeye Power, Inc.	4	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF

Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Scott Moore	Alabama Power Company	3	SERC
					Bill Shultz	Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Rob Vance	New Brunswick Power	1	NPCC
					Mark J. Kenny	Eversource Energy	1	NPCC
					Gregory A. Campoli	NY-ISO	2	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC

					Michele Tondalo	UI	1	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Brian Shanahan	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Michael Forte	Con-Edison	1	NPCC
					Kelly Silver	Con-Edison	3	NPCC
					Peter Yost	Con-Edison	4	NPCC
					Sean Bodkin	Dominion	4	NPCC
					Silvia Parada Mitchell	NextEra Energy	4	NPCC
					Brian O'Boyle	Con-Edison	5	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jason Smith	Southwest Power Pool Inc	2	SPP RE
					Kim VanBrimer	Southwest Power Pool Inc	2	SPP RE
					kevin Giles	Westar Energy	1,3,5,6	SPP RE
					Jonathan Hayes	Southwest Power Pool Inc	2	SPP RE
					J.Scott Williams	City Utilities of Springfield	1,4	SPP RE

1. The SDT has corrected Figure 1 and revised related sections in the Screening Criterion white paper. The SDT has also made related revisions to other Project 2013-03 white papers. Do you agree with the revisions? If not, please provide specific recommendation(s) and technical justification.

Brian Van Gheem - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

We commend the SDT for revising the Screening Criterion and associated Project 2013-03 white papers. These revisions provide additional clarification on why 75 A per phase was chosen as the maximum effective geomagnetically-induced currents (GIC) value for the thermal impact assessment of applicable BES power transformers.

However, based on these clarifications, we believe this after-the-fact exercise to maintain accuracy misses the opportunity to revise the proposed TPL-007-1 reliability standard. The SDT should have justified its actions to revise these documents through the issuance of a SAR, as part of the standards development process. From these clarifications, it's further obvious that the 75 A per phase, while a step in the right direction away from the 15 A per phase value identified in the last draft revision of the standard, still misses the intent of why an overly conservative GIC value was chosen. Based on the information identified within the Screening Criterion and following the revised Table 2, it seems 130 A per phase is a better and more accurate selection for the GIC value.

We recommend the SDT develop a SAR, as part of the standards development process, with the intent to revise Requirement R6 of the standard and remove the maximum effective GIC value reference entirely. We suggest rephrasing the requirement to "each TO and GO shall conduct a thermal impact assessment for its solely and jointly owned applicable BES power transformers based on information provided in Requirement R5. The thermal impact assessment shall consist of [sub-requirements]." These documents could then be updated as part of the standards development process.

Likes 0	
Dislikes 0	

Response

Andrew Pusztai - 1

Answer	Yes
Document Name	

Comment

ATC is fine with the changes to the GMD white papers and have no comments.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - 3,5	
Answer	Yes
Document Name	
Comment	
Though AEP has no objections to the revisions themselves, we do have a question regarding Figure 5 (formally Figure 4) in the document entitled "Screening Criterion for Transformer Thermal Impact Assessment". In short, what data source was used for this particular chart? Was it perhaps from the research conducted in Finland by ABB? If so, the plot does not appear to correlate correctly with this study's data. If this chart is *not* associated with the ABB study, please provide the data source used. In general, we would suggest that data sources be explicitly cited for all charts in the documents.	
Likes 0	
Dislikes 0	
Response	
Larisa Loyferman - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy agrees with the revisions. CenterPoint Energy does not see any major impact with the SDT's proposed changes to the Screening Criterion White Paper, Thermal Impact Assessment, and Benchmark GMD Event White Paper. The changes were made based on the actual data received from the 2003 GMD Halloween storm, which clarified data shown by Figure 1. The SDT consisted of widely-recognized, knowledgeable experts. The Company believes that the members of the SDT are the most qualified to make justified adjustments to the white papers. The Company commends them for their open, thorough, and deliberative process, as well as careful consideration of the full range of technical issues and on the consistency of aligning all the documents at the same time. CenterPoint Energy greatly appreciates the SDT's effort in developing this Standard.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - 1,3,5,6	
Answer	Yes
Document Name	

Comment
Responding on behalf of the Exelon Utilities and Generation companies. Exelon agrees with the revisions made to the Project 2013-03 white papers; we believe, however, that the drafting team missed the opportunity to include in these revisions any reference to the recently approved IEEE Std C57.163, *Guide for Establishing Power Transformer Capability while under Geomagnetic Disturbances*. At a minimum this IEEE Guide should be referenced on page 4 of the *Transformer Thermal Impact Assessment White Paper* as the source of IEEE guidance on conducting a detailed thermal impact assessment. The IEEE Guide also gives detailed information on thermal response of transformers to GIC, evaluation of transformer susceptibility to the effects of GIC, and recommendations regarding transformer specifications and monitoring. The IEEE Guide was developed in an open and collaborative process by more than 150 transformer experts composed of manufacturers, users and consultants from around the globe. Exelon recommends future revisions of the Project 2013-03 white papers should make a point to reference IEEE Std C57.163.

Likes 0	
Dislikes 0	

Response

Ruida Shu - 1,2,3,4,5,6,7 - NPCC, Group Name RSC	
Answer	Yes
Document Name	

Comment
The figure on page 3 of the Screening Criterion for Transformer Thermal Impact Assessment does not have a description. Should it be part of Figure 1? Is just the figure shown on page 4 Figure 1?

Likes 0	
Dislikes 0	

Response

Shannon Mickens - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Comment
Our review group didn't see any major impacts with the drafting teams proposed changes to the three (3) White Papers. We commend them on the consistency of correcting all the documents at the same time. Thank you for all your efforts.

Likes 0	
Dislikes 0	

Response

Katherine Prewitt - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
sean erickson - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - 3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2013-03 Geomagnetic Disturbance Mitigation White Papers
Comment Period Start Date:	5/12/16
Comment Period End Date:	6/13/16

There were 14 responses, including comments from 7 people as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. The SDT has corrected Figure 1 and revised related sections in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper (*Screening Criterion* white paper). The SDT has also made related revisions to other Project 2013-03 white papers. Do you agree with the revisions? If not, please provide specific recommendation(s) and technical justification.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
					Chip Koloini	Golden Spread Electric Cooperative, Inc.	5	SPP RE

					Ellen Watkins	Sunflower Electric Power Corporation	1	SPP RE
					Ryan Strom	Buckeye Power, Inc.	4	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Scott Moore	Alabama Power Company	3	SERC
					Bill Shultz	Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Rob Vance	New Brunswick Power	1	NPCC
					Mark J. Kenny	Eversource Energy	1	NPCC
					Gregory A. Campoli	NY-ISO	2	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC

Alan Adamson	New York State Reliability Council	7	NPCC
Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	UI	3	NPCC
Michele Tondalo	UI	1	NPCC
Kathleen Goodman	ISO-NE	2	NPCC
Sylvain Clermont	Hydro Quebec	1	NPCC
Si Truc Phan	Hydro Quebec	2	NPCC
Helen Lainis	IESO	2	NPCC
Brian Shanahan	National Grid	1	NPCC
Michael Jones	National Grid	3	NPCC
Michael Forte	Con-Edison	1	NPCC
Kelly Silver	Con-Edison	3	NPCC
Peter Yost	Con-Edison	4	NPCC
Sean Bodkin	Dominion	4	NPCC
Silvia Parada Mitchell	NextEra Energy	4	NPCC

					Brian O'Boyle	Con-Edison	5	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jason Smith	Southwest Power Pool Inc	2	SPP RE
					Kim VanBrimer	Southwest Power Pool Inc	2	SPP RE
					kevin Giles	Westar Energy	1,3,5,6	SPP RE
					Jonathan Hayes	Southwest Power Pool Inc	2	SPP RE
					J.Scott Williams	City Utilities of Springfield	1,4	SPP RE

1. The SDT has corrected Figure 1 and revised related sections in the Screening Criterion white paper. The SDT has also made related revisions to other Project 2013-03 white papers. Do you agree with the revisions? If not, please provide specific recommendation(s) and technical justification.

Brian Van Gheem - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Comment	

We commend the SDT for revising the Screening Criterion and associated Project 2013-03 white papers. These revisions provide additional clarification on why 75 A per phase was chosen as the maximum effective geomagnetically-induced currents (GIC) value for the thermal impact assessment of applicable BES power transformers.

However, based on these clarifications, we believe this after-the-fact exercise to maintain accuracy misses the opportunity to revise the proposed TPL-007-1 reliability standard. The SDT should have justified its actions to revise these documents through the issuance of a SAR, as part of the standards development process. From these clarifications, it's further obvious that the 75 A per phase, while a step in the right direction away from the 15 A per phase value identified in the last draft revision of the standard, still misses the intent of why an overly conservative GIC value was chosen. Based on the information identified within the Screening Criterion and following the revised Table 2, it seems 130 A per phase is a better and more accurate selection for the GIC value.

We recommend the SDT develop a SAR, as part of the standards development process, with the intent to revise Requirement R6 of the standard and remove the maximum effective GIC value reference entirely. We suggest rephrasing the requirement to "each TO and GO shall conduct a thermal impact assessment for its solely and jointly owned applicable BES power transformers based on information provided in Requirement R5. The thermal impact assessment shall consist of [sub-requirements]." These documents could then be updated as part of the standards development process.

Response. Thank you for your comment. The SDT analyzed the corrected figure 1 in the *Screening Criterion* white paper and determined that the 75 A per phase threshold for thermal impact assessment remains a valid criterion. Consequently, a SAR to revise the proposed standard is not necessary. The SDT recognizes that 75 A per phase is a conservative screening criterion with a degree of margin, as

discussed on pages 2 and 3 of the *Screening Criterion* white paper. The criterion is used to identify transformers that must undergo a thermal impact assessment as specified in proposed TPL-007-1 Requirement R6 (i.e. 75 A per phase is a screening threshold and not a thermal impact assessment 'pass/fail' indication). The SDT believes it is appropriate to perform thermal impact assessments on transformers that meet or exceed the 75 A per phase threshold for the benchmark GMD event because the potential hot-spot heating in the transformer could exceed thermal limits. Factors such as transformer age and condition could lower the hot-spot heating limit from the 200◦ C value found in IEEE Std C57-91, so it is appropriate for the screening criterion to provide margin. The SDT does not believe revisions in the white paper support changes to Requirement R6 or removal of the thermal screening criterion as suggested by the commenter.
Andrew Pusztai – On Behalf of: American Transmission Company, LLC - 1

Answer	Yes
Comment	
ATC is fine with the changes to the GMD white papers and have no comments.	
Response. Thank you for your comment.	
Thomas Foltz – On Behalf of: AEP - 3,5	
Answer	Yes
Comment	
Though AEP has no objections to the revisions themselves, we do have a question regarding Figure 5 (formally Figure 4) in the document entitled “Screening Criterion for Transformer Thermal Impact Assessment”. In short, what data source was used for this particular chart? Was it perhaps from the research conducted in Finland by ABB? If so, the plot does not appear to correlate correctly with this study’s data. If this chart is *not* associated with the ABB study, please provide the data source used. In general, we would suggest that data sources be explicitly cited for all charts in the documents.	

Response. Thank you for your comment. Figure 5 in the *Screening Criterion* white paper is based on tests of a 400 kV 400 MVA five-leg core-type fully-wound transformer in Finland. The test results are published in the April 2002 IEEE Transactions paper noted as reference [3] in the *Screening Criterion* white paper. Figure 5 is derived from the temperature measurements plotted in reference [3], figure 8 (see Ch 14 plot), for the neutral dc step current profile in reference [3], figure 5.

Larisa Loyferman – On Behalf of: CenterPoint Energy Houston Electric, LLC, Texas RE -1	
Answer	Yes
Comment	
CenterPoint Energy agrees with the revisions. CenterPoint Energy does not see any major impact with the SDT's proposed changes to the Screening Criterion White Paper, Thermal Impact Assessment, and Benchmark GMD Event White Paper. The changes were made based on the actual data received from the 2003 GMD Halloween storm, which clarified data shown by Figure 1. The SDT consisted of widely-recognized, knowledgeable experts. The Company believes that the members of the SDT are the most qualified to make justified adjustments to the white papers. The Company commends them for their open, thorough, and deliberative process, as well as careful consideration of the full range of technical issues and on the consistency of aligning all the documents at the same time. CenterPoint Energy greatly appreciates the SDT's effort in developing this Standard.	

Response. Thank you for your comment.

Chris Scanlon – On Behalf of: Exelon - 1,3,5,6	
Answer	Yes
Comment	
Responding on behalf of the Exelon Utilities and Generation companies. Exelon agrees with the revisions made to the Project 2013-03 white papers; we believe, however, that the drafting team missed the opportunity to include in these revisions any reference to the recently approved IEEE Std C57.163, *Guide for Establishing Power*	

Transformer Capability while under Geomagnetic Disturbances. At a minimum this IEEE Guide should be referenced on page 4 of the *Transformer Thermal Impact Assessment White Paper* as the source of IEEE guidance on conducting a detailed thermal impact assessment. The IEEE Guide also gives detailed information on thermal response of transformers to GIC, evaluation of transformer susceptibility to the effects of GIC, and recommendations regarding transformer specifications and monitoring. The IEEE Guide was developed in an open and collaborative process by more than 150 transformer experts composed of manufacturers, users and consultants from around the globe. Exelon recommends future revisions of the Project 2013-03 white papers should make a point to reference IEEE Std C57.163.
Response. Thank you for your comment. The SDT added a footnote to page 4 of the *Thermal Impact Assessment* white paper referencing IEEE Std C57.163-2015 *Guide for Establishing Power Transformer Capability while under Geomagnetic Disturbances*.

Ruida Shu – Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC	
Answer	Yes
Comment	
The figure on page 3 of the Screening Criterion for Transformer Thermal Impact Assessment does not have a description. Should it be part of Figure 1? Is just the figure shown on page 4 Figure 1?	
Response. Thank you for your comment. The figure on page 3 of the *Screening Criterion* white paper (redline version) is the deleted plot of figure 1 which is being replaced by the plot on page 4. The description for figure 1 is "Metallic hot spot temperatures calculated using the benchmark GMD event."	

Shannon Mickens - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Comment	
Our review group didn't see any major impacts with the drafting teams proposed changes to the three (3) White Papers. We commend them on the consistency of correcting all the documents at the same time. Thank you for all your efforts.	

Response. Thank you for your comment.	
Katherine Prewitt - 1, Group Name Southern Company	
Answer	Yes
Nick Vtyurin – On Behalf of: Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
RoLynda Shumpert – On Behalf of: SCANA – South Carolina Electric and Gas Co. -1,3,5,6 - SERC	
Answer	Yes
Colby Bellville – Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Sean Erickson – On Behalf of: Western Area Power Administration -1,6	
Answer	Yes
Rachel Coyne – On Behalf of: Texas Reliability Entity, Inc. -10	
Answer	Yes
Chris Gowder – On Behalf of: Florida Municipal Power Agency - 3,4,5,6 - FRCC	
Answer	Yes

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Benchmark Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation
Standard Drafting Team
May 12, 2016

RELIABILITY | ACCOUNTABILITY





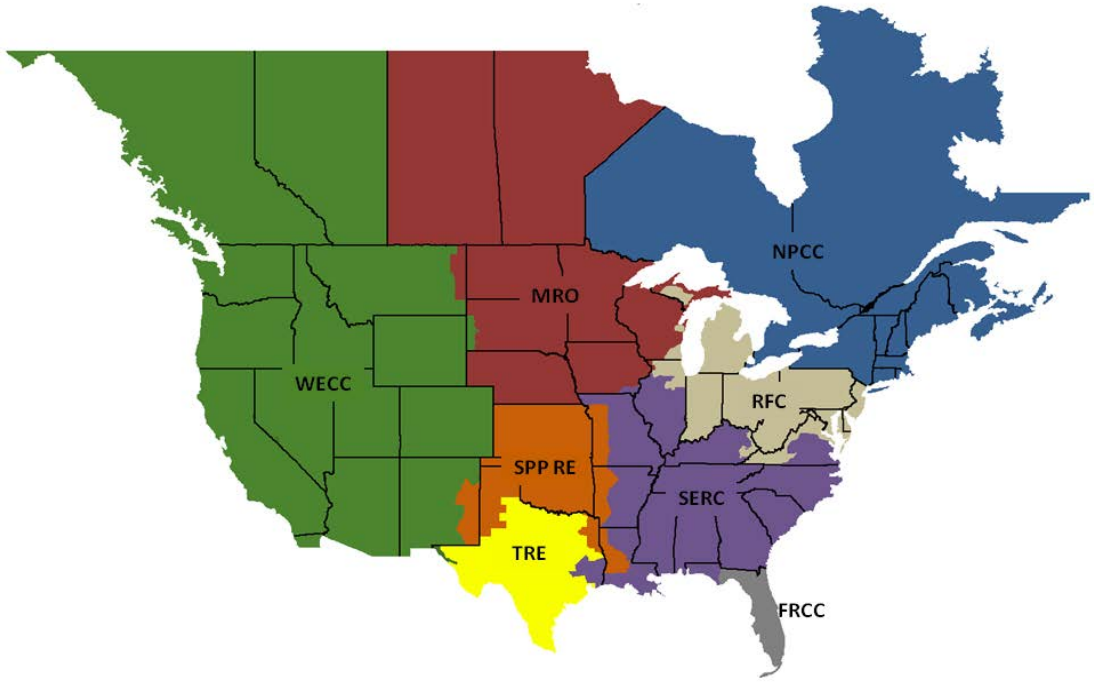

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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure 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 several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Introduction

Background

The purpose of the benchmark geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance during a low probability, high magnitude GMD event as required by proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. The benchmark GMD event defines the geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a GMD Vulnerability Assessment.

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances 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 developed to specifically address the Stage 2 directives in Order No. 779. The benchmark GMD event will define the scope of the Stage 2 Reliability Standard.

General Characteristics

The benchmark GMD event described herein takes into consideration the known characteristics of a severe GMD event and its impact on an interconnected transmission system. These characteristics include:

- Geomagnetic Latitude – The amplitude of the induced geoelectric field for a given GMD event is reduced as the observation point moves away from the earth's magnetic poles.
- Earth Conductivity – The amplitude and phase of the geoelectric field depends on the local or regional earth ground resistivity structure. Higher geoelectric field amplitudes are induced in areas of high resistivity.
- Transformer Electrical Response – Transformers can experience half-cycle saturation when subjected to GIC. Transformers under half-cycle saturation absorb increased amounts of reactive power (var) and inject harmonics into the system. However, half-cycle saturation does not occur instantaneously and depends on the electrical characteristics of the transformer and GIC amplitude [1]. Thus, the effects of transformer reactive power absorption and harmonic generation do not occur instantaneously, but instead may take up to several seconds. It is conservative, therefore, to assume that the effects of GIC on transformer var absorption and harmonic generation are instantaneous.
- Transformer Thermal Effects (e.g. hot spot transformer heating) – Heating of the winding and other structural parts can occur in power transformers during a GMD event. However, the thermal impacts are not instantaneous and are dependent on the thermal time constants of the transformer. Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.
- Geoelectric Field Waveshape – The geoelectric field waveshape 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 magnetic field (dB/dt) is a function of the waveshape, which in turn has a direct effect on the geoelectric field since the earth response to external dB/dt is frequency-dependent.
- Wide Area Geomagnetic Phenomena – The influence of GMD events is typically over a very broad area (e.g. continental scale); however, there can be pockets or very localized regions of enhanced geomagnetic activity. Since geomagnetic disturbance impacts within areas of influence of approximately 100-200 km do not have a widespread impact on the interconnected transmission system (see Appendix I), statistical methods used to assess the frequency of occurrence of a severe GMD event need to consider broad geographical regions to avoid bias caused by spatially localized geomagnetic phenomena.

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. The benchmark 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 waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

The reference geoelectric field amplitude was determined through statistical analysis using the plane wave method [3]-[10] geomagnetic field measurements from geomagnetic observatories in northern Europe [11] and the reference (Quebec) earth model shown in **Table 1** [12]. 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 II) resulted in a conservative peak geoelectric field amplitude of approximately 8 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 frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years (see Appendix I). The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used as the storm return period for determining wind and ice loading of transmission infrastructure [13], for example.

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 8 V/km using the following relationship

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

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 (see Appendix II).

Reference Geomagnetic Field Waveshape

The reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events, including the reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and the March 1989 GMD event that caused the Hydro Quebec blackout. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the

reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers (see Appendix I). The reference geomagnetic field waveshape is 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 1**) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see **Figures 2** and **3**). Sampling rate for the geomagnetic field waveshape is 10 seconds.

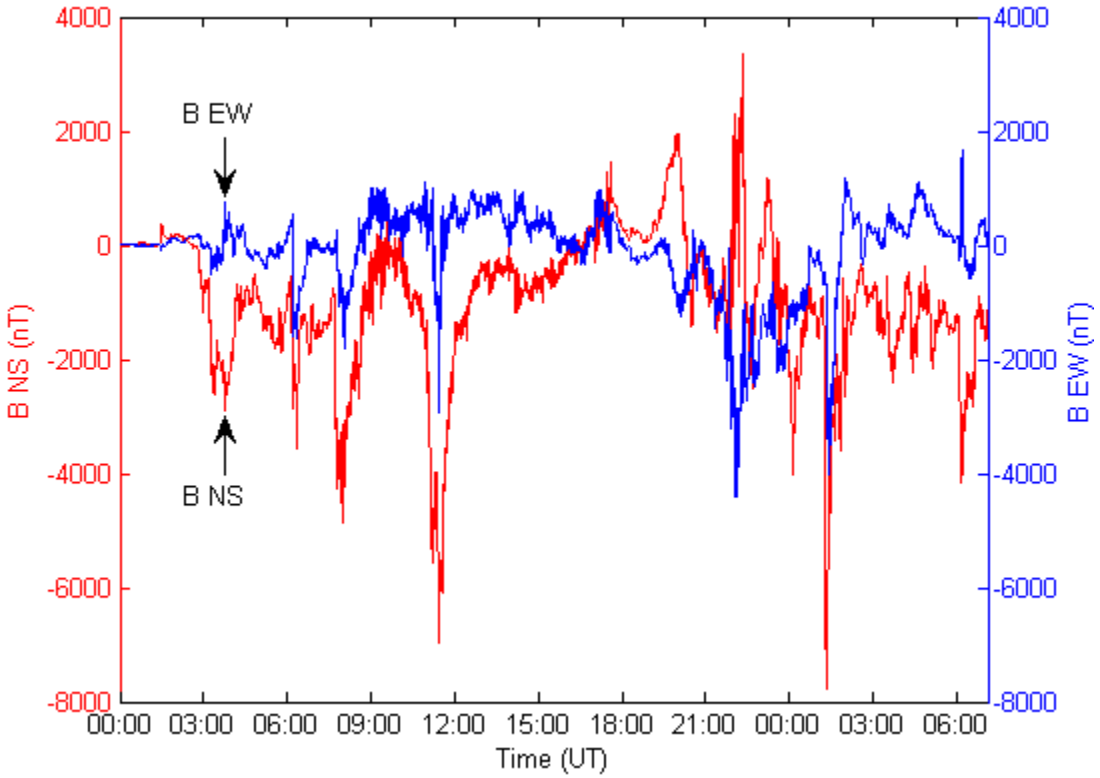


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

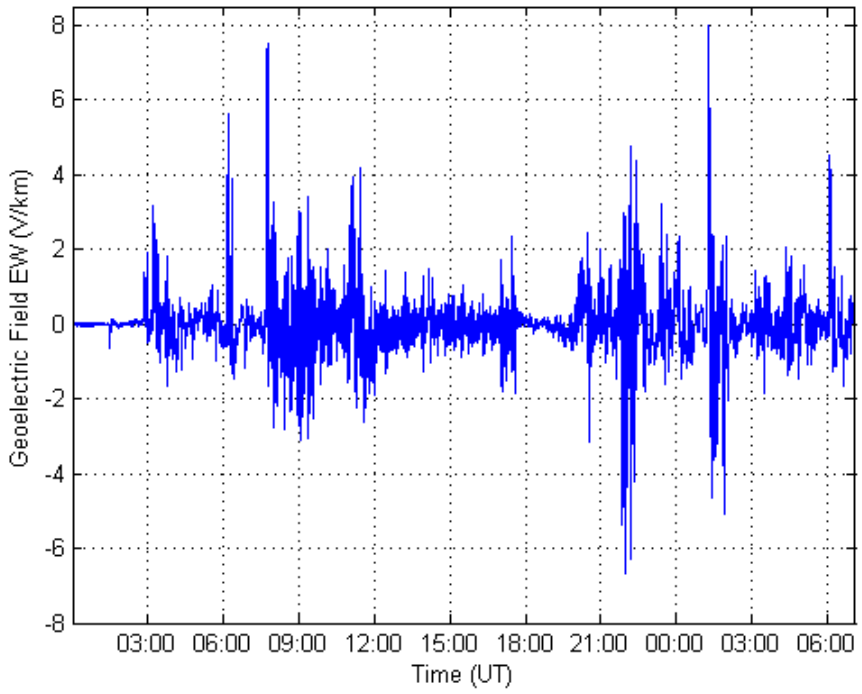


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

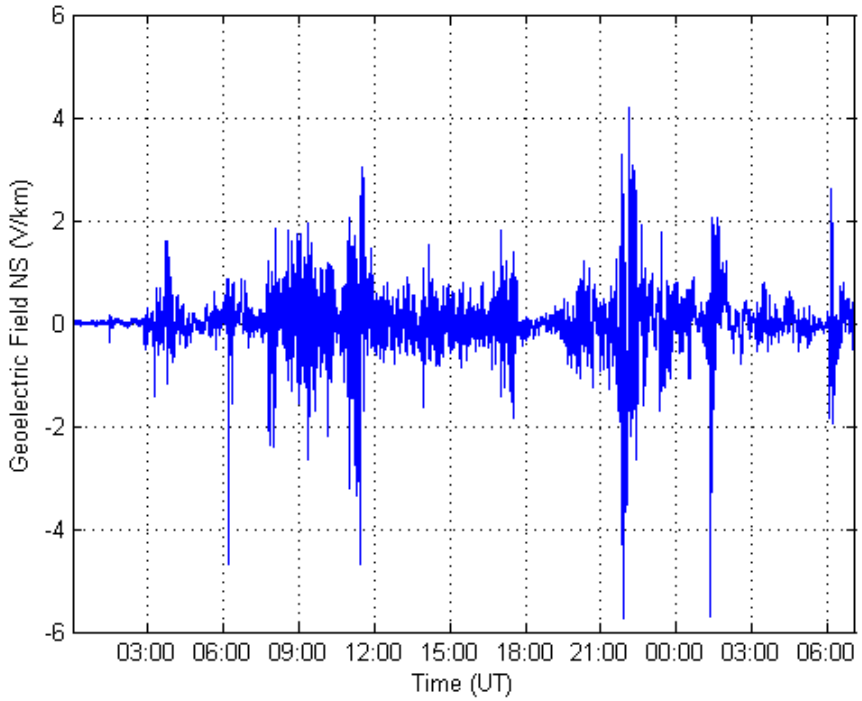


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

The following sections describe the technical justification of the assumptions that were made in the development of the benchmark GMD event.

Statistical Considerations

Due to the lack of long-term accurate geomagnetic field observations, assigning probabilities to the occurrence of historical extreme geomagnetic storms is difficult because of the lack of high fidelity geomagnetic recordings of events prior to the 1980s. This is particularly true for the Carrington event for which data that allow the direct determination of the geoelectric fields experienced during the storm are not available [15].

The storm-time disturbance index Dst has often been used as a measure of storm strength even though it does not provide a direct correspondence with GIC[1]. One of the reasons for using Dst in statistical analysis is that Dst data are available for events occurring prior to 1980. Extreme value analysis of GMD events, including the Carrington, September 1859 and March 1989 events, has been carried out using Dst as an indicator of storm strength. In one such study [16], the (one sigma) range of 10-year occurrence probability for another March 1989 event was estimated to be between 9.4-27.8 percent. The range of 10-year occurrence probability for Carrington event in Love's analysis is 1.6-13.7 percent. These translate to occurrence rates of approximately 1 in 30-100 years for the March 1989 event and 1 in 70-600 years for the Carrington event. The error bars in such analysis are significant, however, it is reasonable to conclude that statistically the March 1989 event is likely more frequent than 1-in-100 years and the Carrington event is likely less frequent than 1-in-100 years.

The benchmark GMD event is based on a 1 in 100 year frequency of occurrence which is a conservative design basis for power systems. Also, the benchmark GMD event is not biased towards local geomagnetic field enhancements, since it must address wide-area effects in the interconnected power system. Therefore, the use of Dst-based statistical considerations is not adequate in this context and only relatively modern data have been used.

The benchmark GMD event is derived from modern geomagnetic field data records and corresponding calculated geoelectric field amplitudes. Using such data allows rigorous statistical analysis of the occurrence rates of the physical parameter (i.e. rate of change in geomagnetic field, dB/dt) directly related to the geoelectric field. Geomagnetic field measurements from the IMAGE magnetometer chain for 1993-2013 have been used to study the occurrence rates of the geoelectric field amplitudes.

With the use of modern data it is possible to avoid bias caused by localized geomagnetic field enhancements. The spatial structure of high-latitude geoelectric fields can be very complex during strong geomagnetic storm events [17]-[18]. One reflection of this spatial complexity is localized geomagnetic field enhancements that result in high amplitude geoelectric fields in regions of a few hundred kilometers or less. **Figure I-1**[2] illustrates this spatial complexity of the storm-time geoelectric fields. In areas indicated by the bright red location, the geoelectric field can be a factor of 2-3 larger than at neighboring locations. Localized geomagnetic phenomena should not be confused with local earth structure/conductivity features that result in consistently high geoelectric fields (e.g., coastal effects). Localized field enhancements can occur at any region exposed to auroral ionospheric electric current fluctuations.

[1] Dst index quantifies the amplitude of the main phase disturbance of a magnetic storm. The index is derived from magnetic field variations recorded at four low-latitude observatories. The data is combined to provide a measure of the average main-phase magnetic storm amplitude around the world.

[2] **Figure I-1** 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.

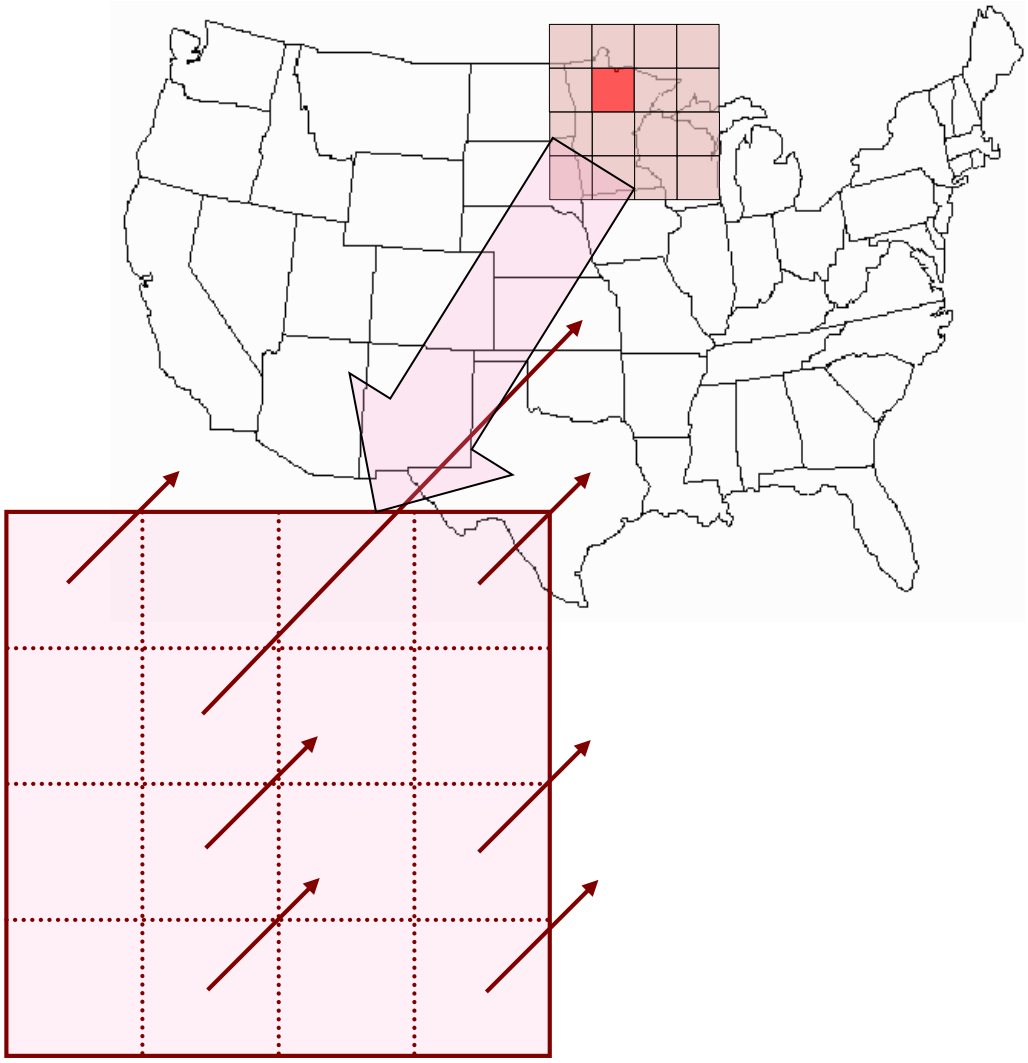


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

The benchmark event is designed to address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse. It is important to note that most earlier geoelectric field amplitude statistics and extreme amplitude analyses have been built for individual stations thus reflecting only localized spatial scales [10], [19]-[22]. A modified analysis is required to account for geoelectric field amplitudes at larger spatial scales. Consequently, analysis of spatially averaged geoelectric field amplitudes is presented below.

Figure I-2 shows statistical occurrence of spatially averaged high latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013. The geoelectric field amplitudes were calculated using 10-s IMAGE magnetometer array observations and the Quebec ground conductivity model, which is used as a reference in the benchmark GMD event. Spatial averaging was carried out over four different station groups spanning a square area of approximately 500 km in width. For the schematic situation in **Figure I-1** the averaging process involves taking the average of the geoelectric field amplitudes over all 16 points or squares.

As can be seen from **Figure I-2**, the computed spatially averaged geoelectric field amplitude statistics indicate the 1-in-100 year amplitude is approximately between 3-8 V/km. Using extreme value analysis as described in the next section, it can be shown that the upper limit of the 95% confidence interval for a 100-year return level is more precisely 5.77 V/km.

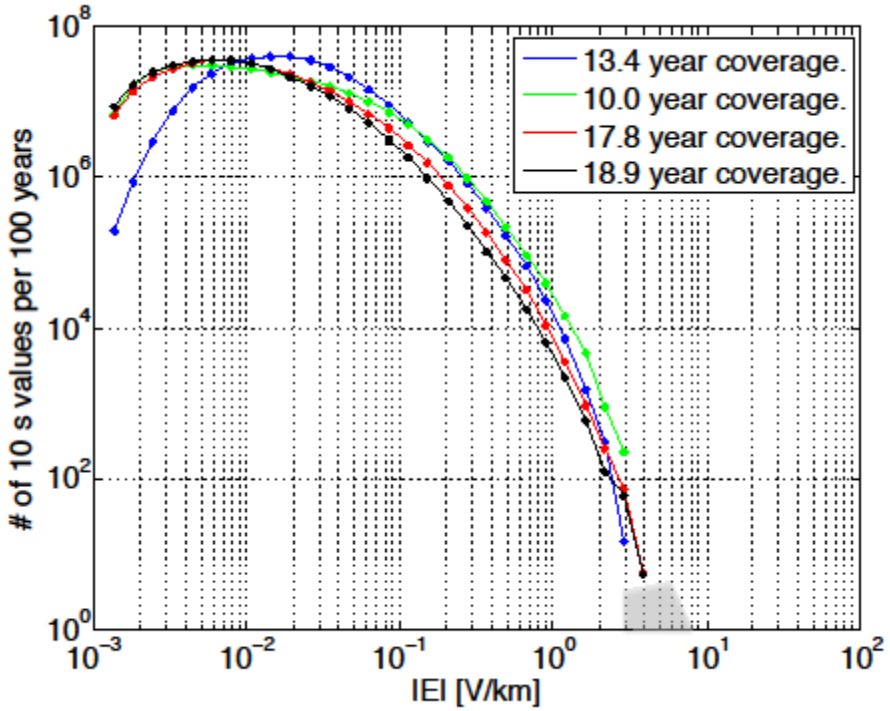


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes.
Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the averaged geoelectric field amplitudes.

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 percent confidence interval of the maximum geoelectric field amplitude to be expected within a 100-year return period.[3] In the context of this document, extreme value analysis has been used to rigorously support the extrapolation estimates used in the statistical considerations of the previous section.

The data set consists of 21 years of daily maximum geoelectric field amplitudes derived from the IMAGE magnetometer chain, using the Quebec earth model as reference. **Figure I-3** shows a scatter plot of the 10-largest geoelectric field amplitudes per year across the IMAGE stations. The plot indicates that both the amplitude and standard deviation of extreme geoelectric fields are not independent of the solar cycle. The data clearly exhibits heteroskedasticity[4] and an 11-year seasonality in the mean.

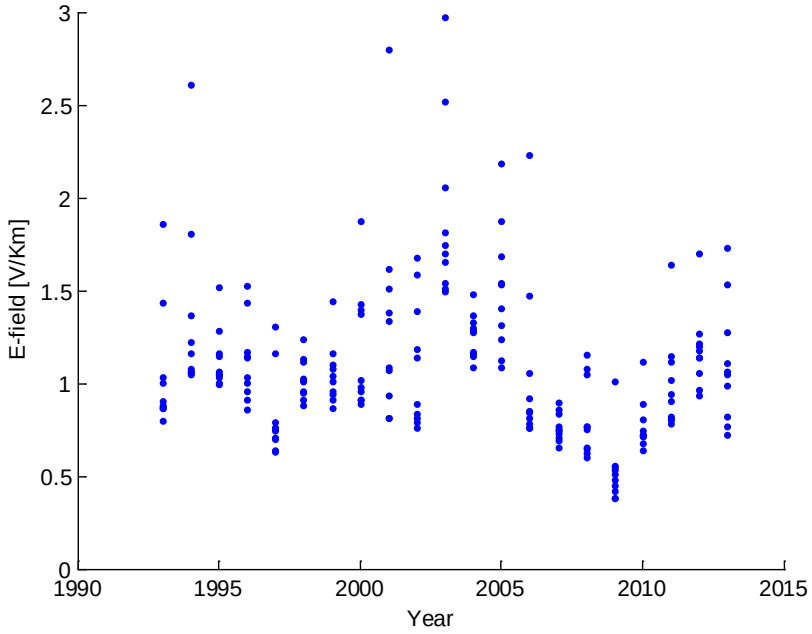


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

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 [23].

Two of these methods, GEV and POT, have been applied to the geoelectric field data, and their suitability for this application has been examined. **Table I-1** shows a summary of the estimated parameters and return levels obtained from GEV and POT 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 percent confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the

[3] 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.

[4] Heteroskedasticity means that the skedastic function depends on the values of the conditioning variable; i.e., *var(Y|X=x) = f(x)*.

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 Method	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=1.4499 (0.1090) σ=0.4297 (0.0817) ξ=0.0305 (0.2011)	H0: ξ=0 p = 0.877	3.57	[1.77 , 5.36]	[2.71, 10.26]
(2) GEV $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=1.5047 (0.0753) β_1=0.3722 (0.0740) σ=0.2894 (0.0600) ξ=0.1891 (0.2262)	H0: β_1=0 p= 0.0003 H0: ξ=0 p = 0.38	4	[2.64, 4.81]	[2.92, 12.33]
(3) POT, threshold=1V/km	σ=0.3163 (0.0382) ξ=0.0430 (0.0893)		3.4	[2.28, 4.52]	[2.72,5.64]
(4) POT, threshold=1V/km $\sigma = \alpha_0 + \alpha_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	α_0=0.2920 (0.0339) α_1=0.1660 (0.0368) ξ=-0.0308 (0.0826)	H0: α_1=0 p= 3.7e-5	3.724	[2.64, 4.81]	[3.02, 5.77]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 21 data points are used in the estimation. The mean expected amplitude of the geolectric field for a 100-year return level is 3.57 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach. This is reflected in the comparatively large confidence intervals: [1.77, 5.36] V/km for the delta method and [2.71, 10.26] V/km for the profile likelihood.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure 1-3**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a re-parameterization 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: β_1=0, is rejected with a p-value of 0.0003; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the re-parameterized GEV. The benefit is an increase in the mean return

level to 4 V/km and a wider confidence interval: [2.63, 4.81] V/km for the delta method and [2.92, 12.33] 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 1 V/km; the data was de-clustered 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; a threshold that is too low will likely lead to bias. On the other hand, a threshold that is too high will reduce the sample size and result in high variance. The stability of parameter estimates can guide the selection of an appropriate threshold. **Figure I-4** shows the estimated parameters (modified scale $\sigma^*=\sigma_u-\xi\cdot u$, and shape ξ) for a range of thresholds. The objective is to select the lowest threshold for which the estimates remain near constant; 1V/km appears to be a good choice.

The mean return level for statistical model (3), 3.4 V/km, is similar to the GEV estimates. However, due to the larger sample size, the POT method is more efficient, and consequently, the confidence intervals are significantly reduced: [2.28, 4.52] V/km for the delta method, and [2.72, 5.64] V/km for the profile likelihood method.

In order to cope with the heteroskedasticity exhibited by the data, a re-parameterization of POT is used 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 statistically significant; the null hypothesis, H0: $\alpha_1=0$, is rejected with a p-value of 3.7e-5. The mean return level has slightly increased to 3.72 V/km. The upper limit of the confidence interval, calculated at solar maximum, also increases: [2.63, 4.81] V/km for the delta method and [3.02, 5.77] V/km for the profile likelihood method. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method. **Figure I-5** shows the profile likelihood of the 100-year return level of statistical model (4). 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.

To conclude, traditional GEV (1) and POT (3) models are misspecified; the statistical assumptions (iid) are not warranted by the data. The models were re-parameterized to cope with heteroskedasticity and the 11-year seasonality in the mean. Statistical model (4) better utilizes the available extreme measurements and it is therefore preferred over statistical model (2). The upper limit of the 95 percent confidence interval for a 100-year return level is 5.77 V/km. This analysis is consistent with the selection of a geoelectric field amplitude of 8 V/km for the 100-year GMD benchmark. .

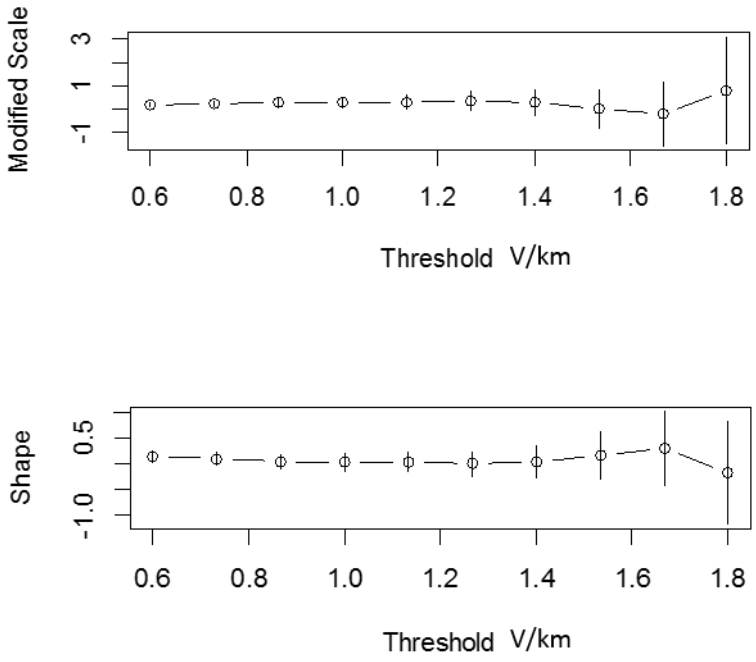


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

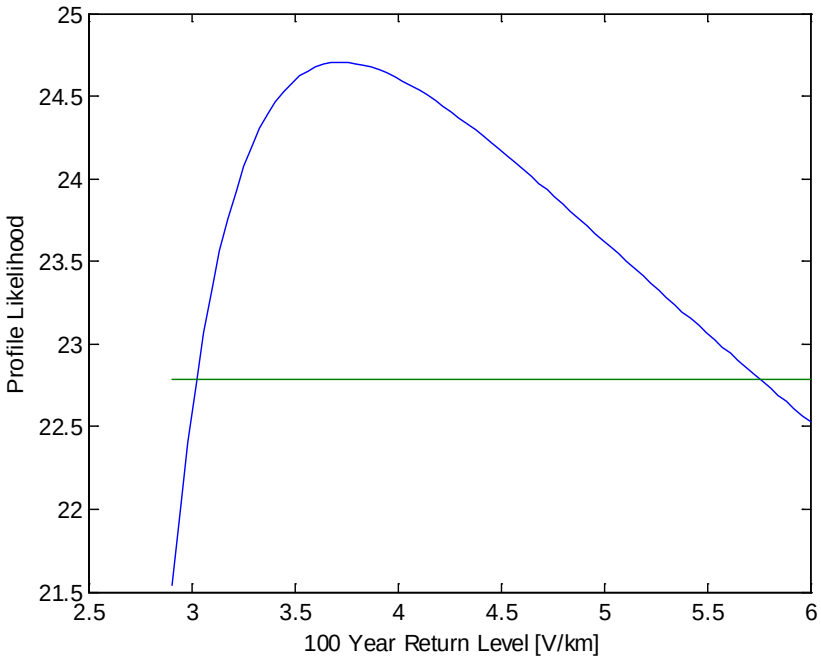


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

The impact of local disturbances on a power network is illustrated with the following example. A 500 km by 500 km section of a North American transmission network is subdivided into 100 km by 100 km sections. The geoelectric field is assumed to be uniform within each section. The analysis is performed by scaling the geoelectric field in each section individually by an intensification factor of 2.5 and computing the corresponding GIC flows in the network, resulting in a total of 25 GIC distribution simulations.[5] In these simulations the peak geomagnetic field amplitude has been scaled according to geomagnetic latitude of the network under study.

Figure I-6 shows the number of transformers that experience a GIC increase greater than 10 Amps (in red), those that experienced a reduction in GIC of more than 10 Amps (in blue), and those that remain essentially the same (in green). It can be observed that there is a small set of transformers that are affected by the local amplification of the geo-electric field but that the impact on the GIC distribution of the entire network due to a local intensification of the geoelectric field in a "local peak" is minor. Therefore, it can be concluded that the effect of local disturbances on the larger transmission system is relatively minor and does not warrant further consideration in network analysis.

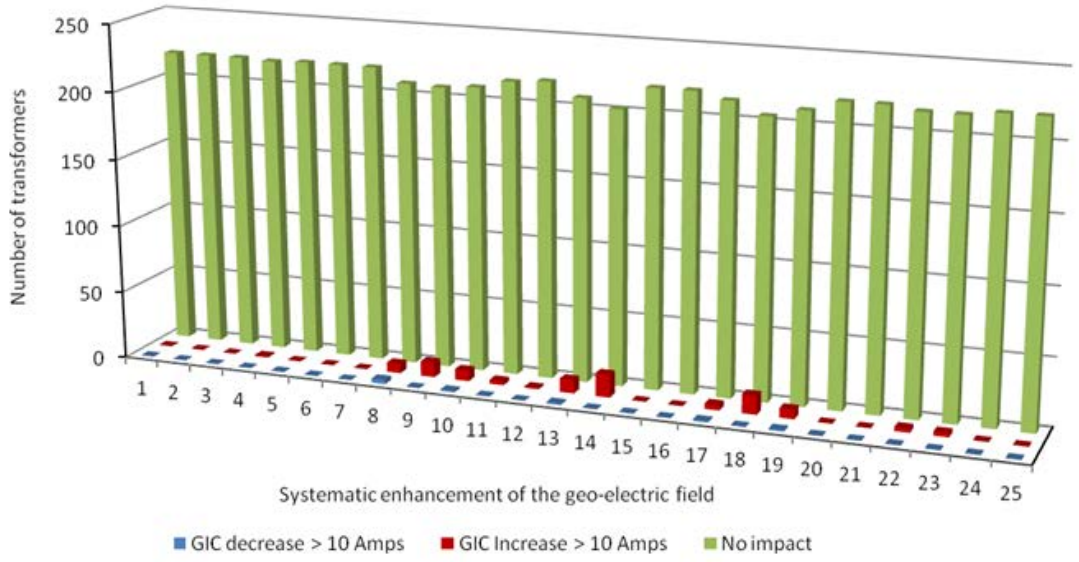


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

Thermal effects (e.g. hot spot transformer heating) in power transformers are not instantaneous. Thermal time constants associated with hot spot heating in power transformers are in the 5-20 minute range; therefore, the waveshape of the geomagnetic and geoelectric field has a strong impact on transformer hot spot heating of windings and metallic parts since thermal time constants are of the same order of magnitude as the time-to-peak of storm maxima. The waveshape of the March 13-14 1989 GMD event measured at the Ottawa geomagnetic observatory was found to be a conservative choice when compared with other events of the last 20 years, such

[5] An intensification factor of 2.5 would make a general 8 V/km peak geoelectric field in the entire network show a 20 V/km intensified geoelectric field in one of the twenty five 100 km by 100 km sections.

as the measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003 described in the NERC GMD interim report of 2012 [14].

To illustrate, the results of a thermal analysis performed on a relatively large test network with a diverse mix of circuit lengths and orientations is provided in **Figures I-7** and **I-8**. **Figure I-9** shows a more systematic way to compare the relative effects of storm waveshape on the thermal response of a transformer. It shows the results of 33,000 thermal assessments for all combinations of effective GIC due to circuit orientation (similar **to Figures I-7** and **I-8** but systematically taking into account all possible circuit orientations). These results illustrate the relative effect of different waveshapes in a broad system setting and should not be interpreted as a vulnerability assessment of any particular network.

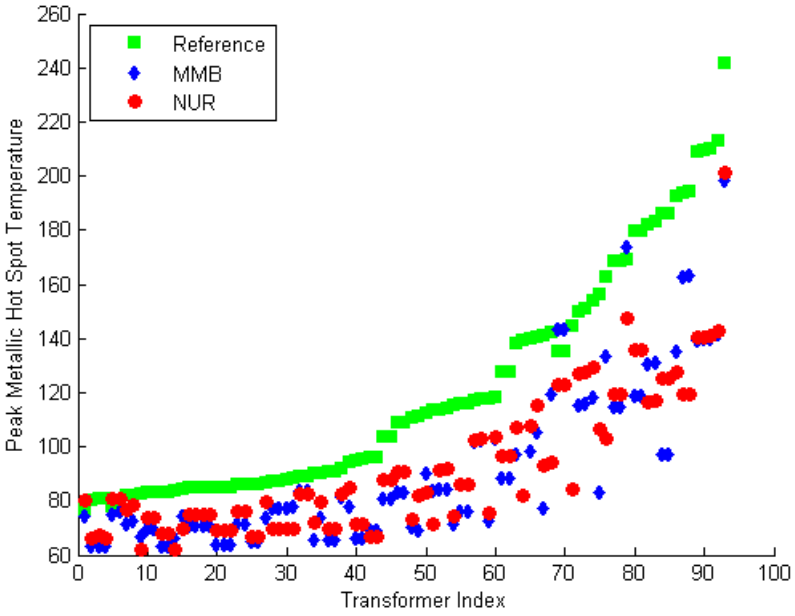


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

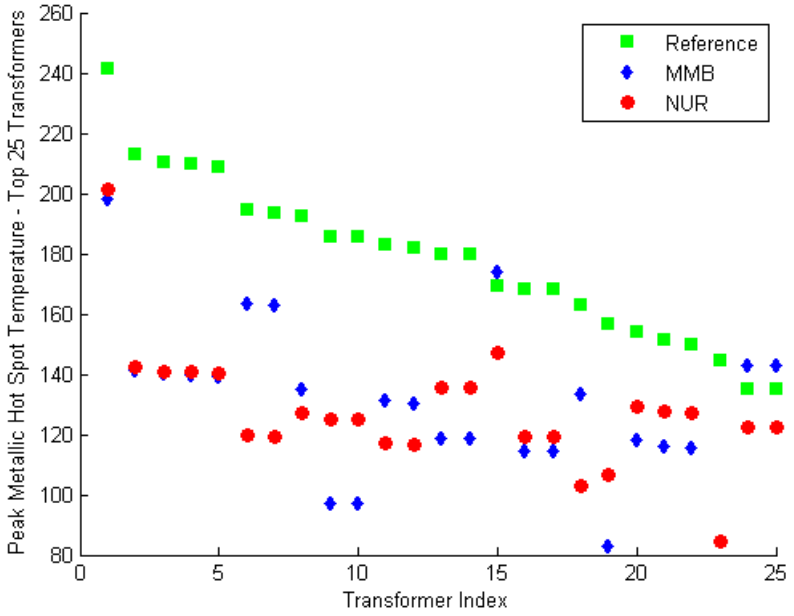


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field

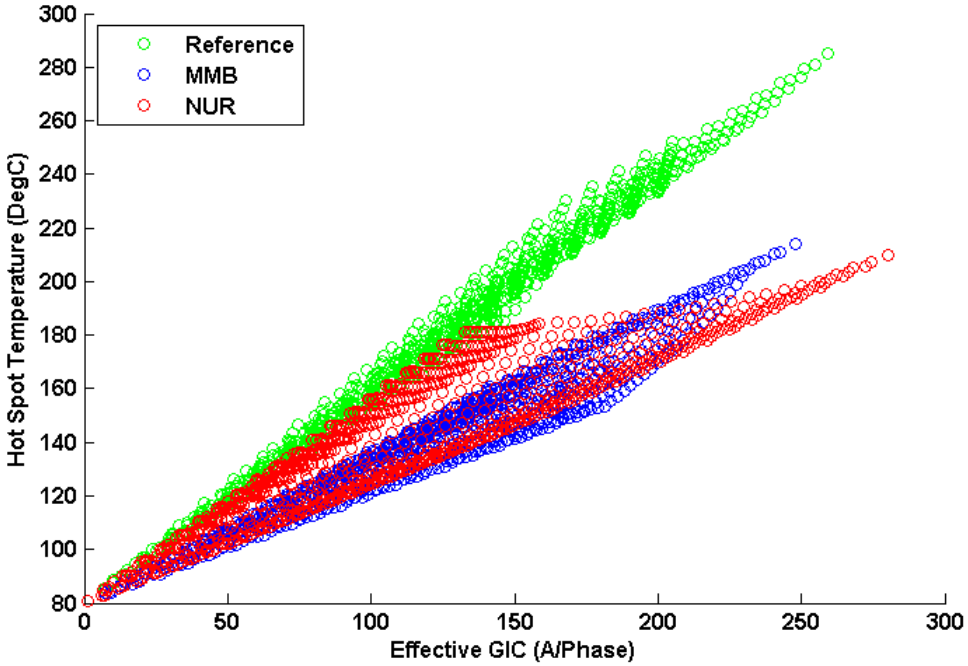


Figure I-9: Calculated Peak Metallic Hot Spot Temperature for all possible circuit orientations and effective GIC.

Appendix II – Scaling the Benchmark GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude[6] and local earth conductivity[7] [3]**.** 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 Geomagnetic Field

The benchmark 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 reference geomagnetic field waveshape 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], [24]-[25], 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 $0.1 \leq \alpha \leq 1.0$.

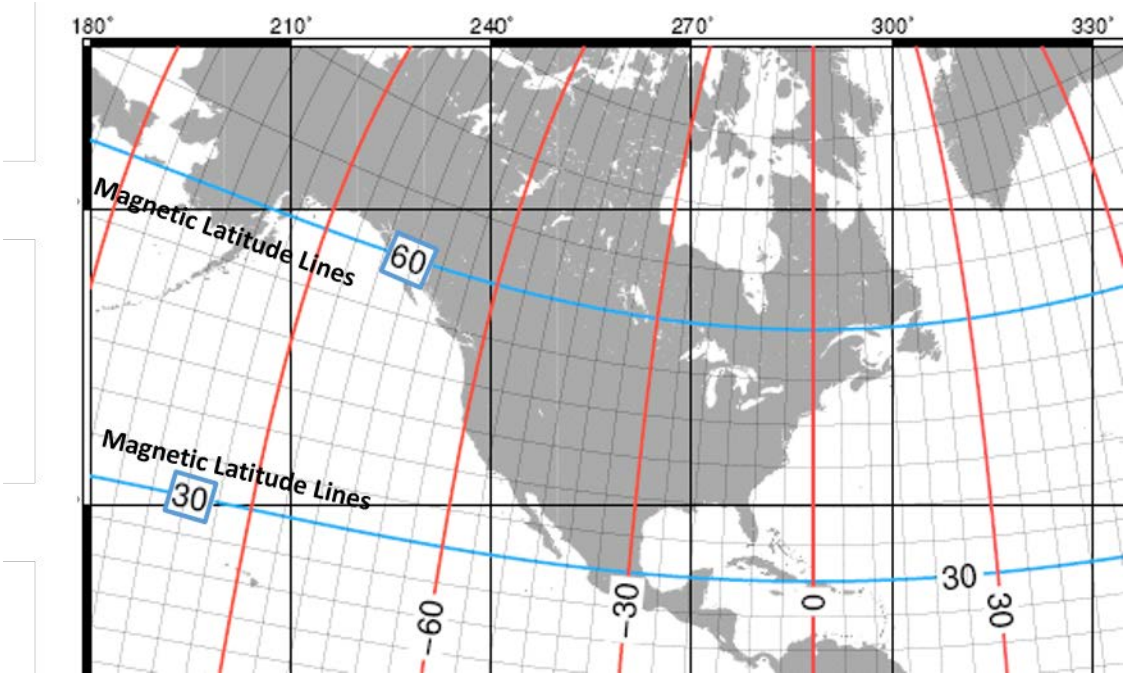


Figure II-1: Geomagnetic Latitude Lines in North America

[6] 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.

[7] 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.

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 benchmark 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 [12, 15]. The peak geoelectric field depends on the geomagnetic field waveshape and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic waveshape using the plane wave method and taking the maximum value of the resulting waveforms

$$E_N = (z(t)/\mu_o) * B_E(t)$$
$$E_E = -(z(t)/\mu_o) * B_N(t) \qquad \text{(II.2)}$$
$$E_{peak} = \max\left\{\left|E_E(t), E_N(t)\right|\right\}$$

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 waveshapes,

$E_E(t)$, $E_N(t)|$ 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.

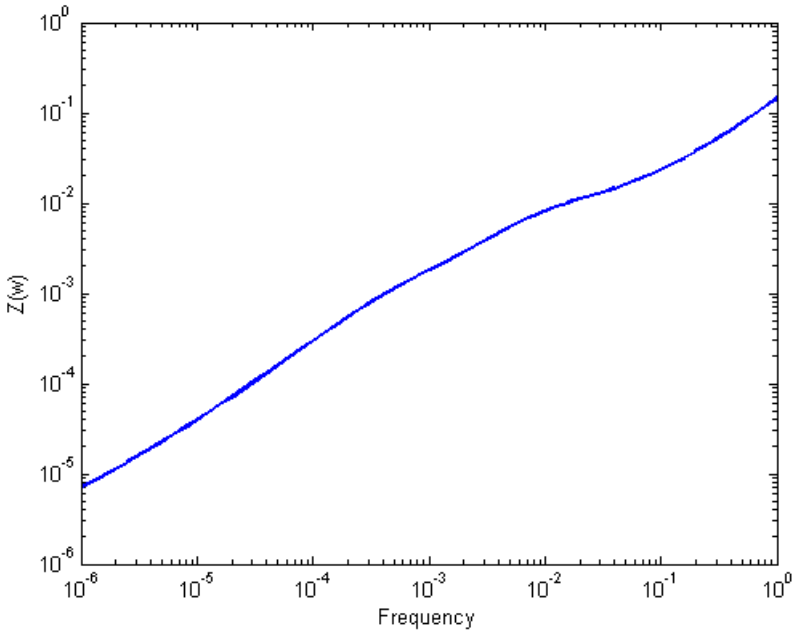


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

If a utility does not have the capability of calculating the waveshape or time series for the geoelectric field, an earth conductivity scaling factor β 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)

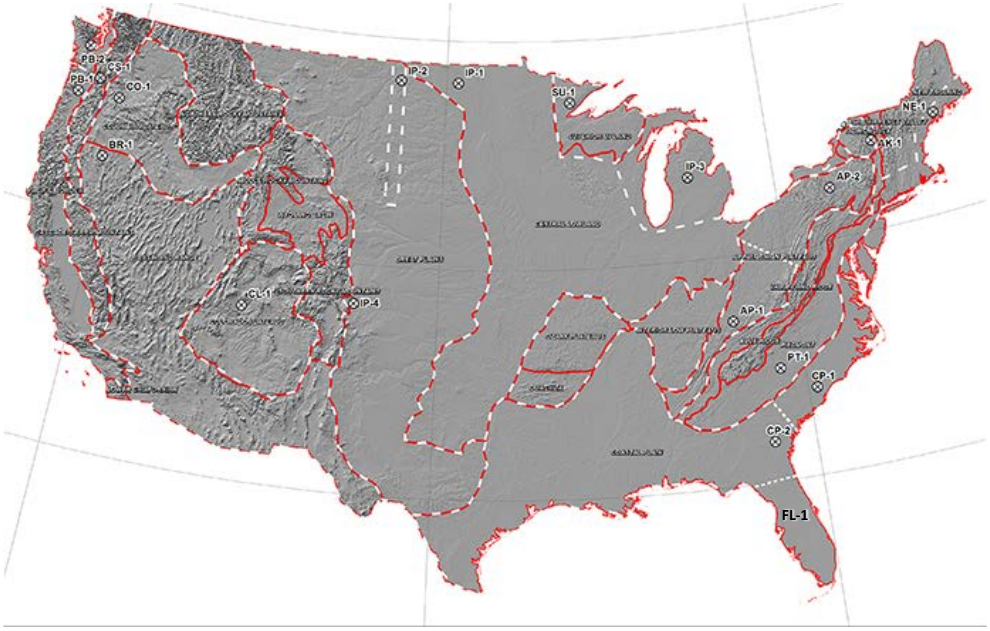
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad \text{(II.3)}$$

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.
- 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 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 8 V/km. Both geoelectric field peaks amplitudes are calculated using the reference 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. However, the reference time series produces generally more conservative values of β when compared to the time series of reference storm of the NERC interim report of 2012 [14], measurements at the Nurmijarvi (NUR) and Memanbetsu (MMB) geomagnetic observatories for the "Halloween event" of October 29-31, 2003, and other recordings of the March 1989 event at high latitudes (Meanook observatory, Canada). The average variation between minimum and maximum β is approximately 12 percent. **Figure II-4** illustrates the values of β calculated using the 10-second recordings for these geomagnetic field time series.
- 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 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 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

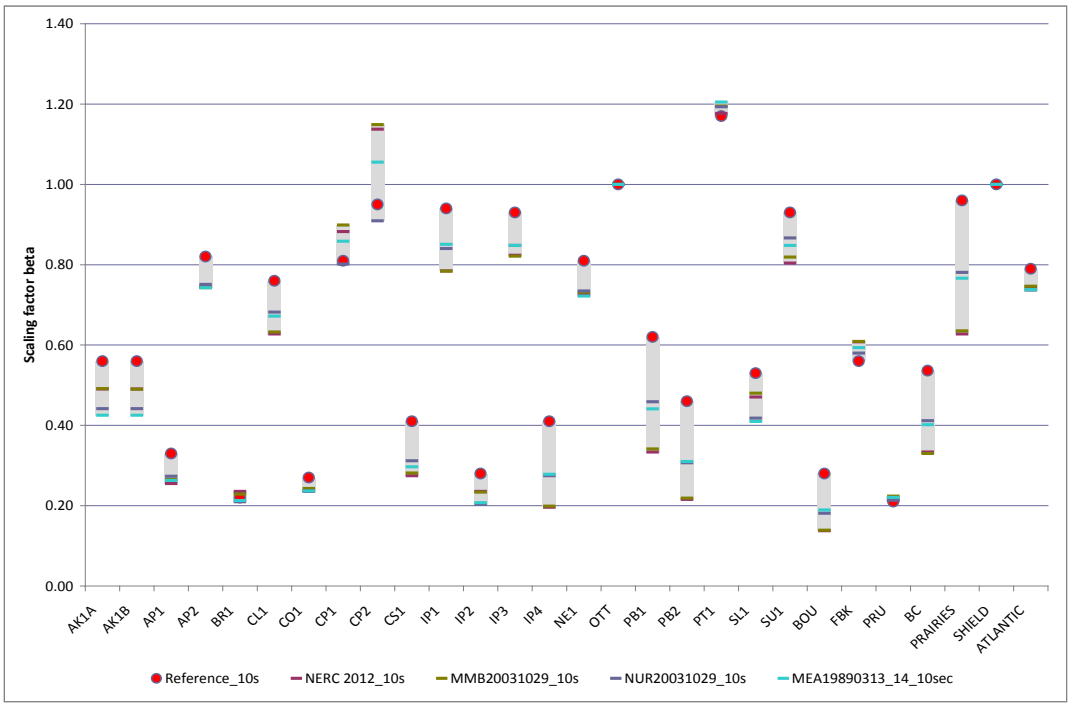


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles correspond to the values in Table II-2

Example Calculations

Example 1

Consider a transmission service territory that lies in a geographical latitude of 45.5°, which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly. If the service territory has the same earth conductivity as the benchmark then β=1, and the peak geoelectric field will be

$$\alpha = 0.56$$
$$\beta = 1.0$$
$$E_{peak} = 8 \times 0.56 \times 1 = 4.5 V/km$$

If the service territory spans more than one physiographic region (i.e. several locations within the service territory have a different earth model) then the largest α can be used across the entire service territory for conservative results. Alternatively, the network can be split into multiple subnetworks, and the corresponding geoelectric field amplitude can be applied to each subnetwork.

Example 2

Consider a service territory that lies in a geographical latitude of 45.5° which translates to a geomagnetic latitude of 55°. The scaling factor α calculated using II.1 is 0.56; therefore, the benchmark waveshape and the peak geoelectric field will be scaled accordingly.

The service territory has lower conductivity than the reference benchmark conductivity, therefore, according to the conductivity factor β from Table II-2., the calculation follows:

Conductivity factor β=1.17

$$\alpha = 0.56$$

$$E_{peak} = 8 \times 0.56 \times 1.17 = 5.2V / km$$

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Screening Criterion for Transformer Thermal Impact Assessment

Project 2013-03 (Geomagnetic Disturbance Mitigation)

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

Summary

Proposed standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events requires applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. The standard requires transformer thermal impact assessments to be performed on power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. Transformers are exempt from the thermal impact assessment requirement if the maximum effective geomagnetically-induced current (GIC) in the transformer is less than 75 A per phase as determined by GIC analysis of the system. Based on published power transformer measurement data as described below, an effective GIC of 75 A per phase is a conservative screening criterion. To provide an added measure of conservatism, the 75 A per phase threshold, although derived from measurements in single-phase units, is applicable to transformers with all core types (e.g., three-limb, three-phase).

Justification

Applicable entities are required to carry out a thermal assessment with GIC(t) calculated using the benchmark GMD event geomagnetic field time series or waveshape for effective GIC values above a screening threshold. The calculated GIC(t) for every transformer will be different because the length and orientation of transmission circuits connected to each transformer will be different even if the geoelectric field is assumed to be uniform. However, for a given thermal model and maximum effective GIC there are upper and lower bounds for the peak hot spot temperatures. These are shown in **Figure 1** using three available thermal models based on direct temperature measurements.

The results shown in **Figure 1** summarize the peak metallic hot spot temperatures when GIC(t) is calculated using (1), and systematically varying GIC_E and GIC_N to account for all possible orientation of circuits connected to a transformer. The transformer GIC (in A/phase) for any value of E_E (t) and E_N(t) can be calculated using equation (1) from reference [1].

$$GIC(t) = \left|E(t)\right| \cdot \left\{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\right\} \quad (1)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \tag{2}$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \tag{3}$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \tag{4}$$

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/V/km.

It should be emphasized that with the thermal models used and the benchmark GMD event geomagnetic field waveshape, peak hot spot temperatures must lie below the envelope shown in **Figure 1**. The x-axis in Figure 1 corresponds to the absolute value of peak GIC(t). Effective maximum GIC for a transformer corresponds to a worst-case geoelectric field orientation, which is network-specific. Figure 1 represents a possible range, not the specific thermal response for a given effective GIC and orientation.

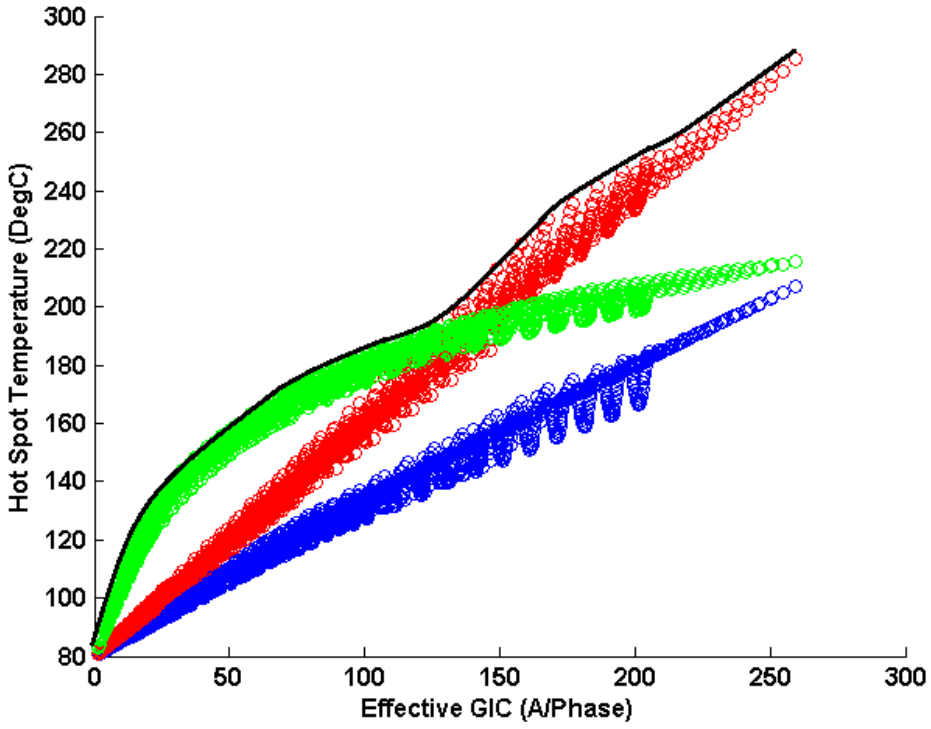


Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: SVC coupling transformer model [2]. Blue: Fingrid model [3]. Green: Autotransformer model [4].

Consequently, with the most conservative thermal models known at this point in time, the peak metallic hot spot temperature obtained with the benchmark GMD event waveshape assuming an effective GIC magnitude of 75 A per phase will result in a peak temperature between 160°C and 172°C when the bulk oil temperature is 80°C (full load bulk oil temperature). The upper boundary of 172°C remains well below the metallic hot spot 200°C threshold for short-time emergency loading suggested in IEEE Std C57.91-2011 [5] (see Table 1).

TABLE 1:
Excerpt from Maximum Temperature Limits Suggested in IEEE C57.91-2011

	Normal life expectancy loading	Planned loading beyond nameplate rating	Long-time emergency loading	Short-time emergency loading
Insulated conductor hottest-spot temperature °C	120	130	140	180
Other metallic hot-spot temperature (in contact and not in contact with insulation), °C	140	150	160	200
Top-oil temperature °C	105	110	110	110

The selection of the 75 A per phase screening threshold is based on the following considerations:

- A thermal assessment using the most conservative thermal models known to date will not result in peak hot spot temperatures above 172°C. Transformer thermal assessments should not be required by Reliability Standards when results will fall well below IEEE Std C57.91-2011 limits.
- Applicable entities may choose to carry out a thermal assessment when the effective GIC is below 75 A per phase to take into account the age or condition of specific transformers where IEEE Std C57.91- 2011 limits could be assumed to be lower than 200°C.
- The models used to determine the 75 A per phase screening threshold are known to be conservative at higher values of effective GIC, especially the SVC coupling transformer model in [2].
- Thermal models in peer-reviewed technical literature, especially those calculated models without experimental validation, are less conservative than the models used to determine the screening threshold. Therefore, a technically-justified thermal assessment for effective GIC below 75 A per phase using the benchmark GMD event geomagnetic field waveshape will always result in a "pass" on the basis of the state of the knowledge at this point in time.
- Based on simulations, the 75 A per phase screening threshold will result in a maximum instantaneous peak hot spot temperature of 172°C. However, IEEE Std C57.91- 2011 limits assume short term emergency operation (typically 30 minutes). As illustrated in **Figure 2**, simulations of the 75 A per phase screening threshold result in 30-minute duration hot spot temperatures of about

155°C. The threshold provides an added measure of conservatism in not taking into account the duration of hot spot temperatures.

- The models used in the determination of the threshold are conservative but technically justified.
- Winding hot spots are not the limiting factor in terms of hot spots due to half-cycle saturation, therefore the screening criterion is focused on metallic part hot spots only.

The 75 A per phase screening threshold was determined using single-phase transformers, but is applicable to all types of transformer construction. While it is known that some transformer types such as three-limb, three-phase transformers are intrinsically less susceptible to GIC, it is not known by how much, on the basis of experimentally-supported models.

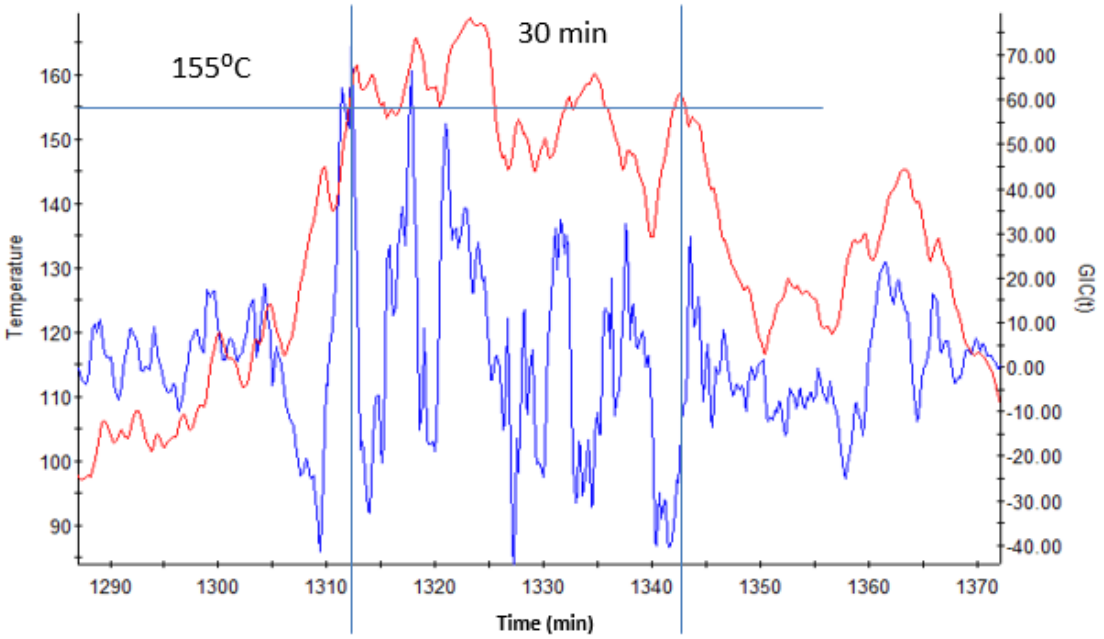


Figure 2: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: metallic hot spot temperature. Blue: GIC(t) that produces the maximum hot spot temperature with peak GIC(t) scaled to 75 A/phase.

Appendix

The envelope used for thermal screening (Figure 1) is derived from two thermal models. The first is based on laboratory measurements carried out on 500/16.5 kV 400 MVA single-phase Static Var Compensator (SVC) coupling transformer [2]. Temperature measurements were carried out at relatively small values of GIC (see **Figure 3**). The asymptotic thermal response for this model is the linear extrapolation of the known measurement values. Although the near-linear behavior of the asymptotic thermal response is consistent with the measurements made on a Fingrid 400 kV 400 MVA five-leg core-type fully-wound transformer [3] (see **Figures 4 and 5**), the extrapolation from low values of GIC is very conservative, but reasonable for screening purposes.

The second transformer model is based on a combination of measurements and modeling for a 400 kV 400 MVA single-phase core-type autotransformer [4] (see **Figures 6 and 7**). The asymptotic thermal behavior of this transformer shows a "down-turn" at high values of GIC as the tie plate increasingly saturates but relatively high temperatures for lower values of GIC. The hot spot temperatures are higher than for the two other models for GIC less than 125 A per phase.

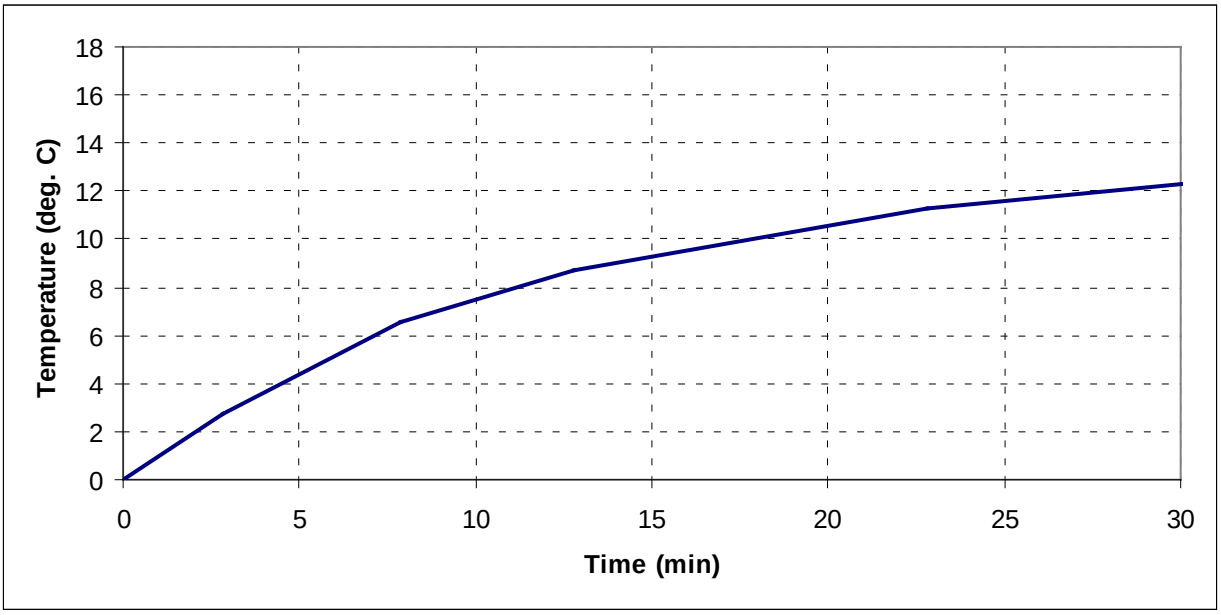


Figure 3: Thermal step response of the tie plate of a 500 kV 400 MVA single-phase SVC coupling transformer to a 5 A per phase dc step.

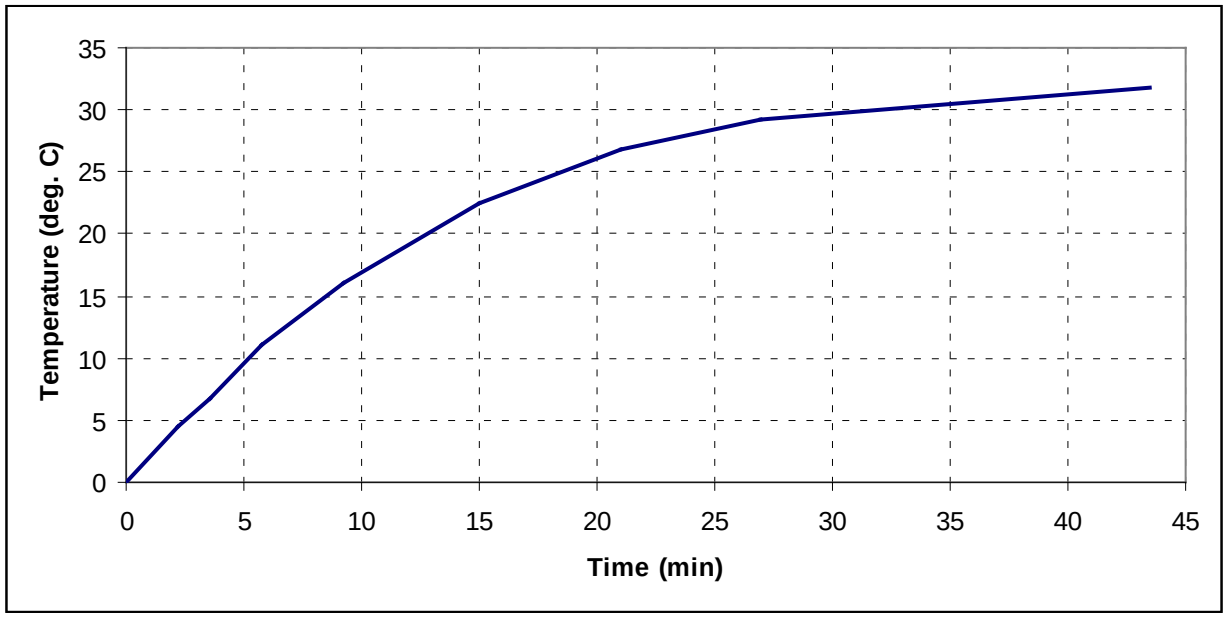


Figure 4: Step thermal response of the top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer to a 16.67 A per phase dc step.

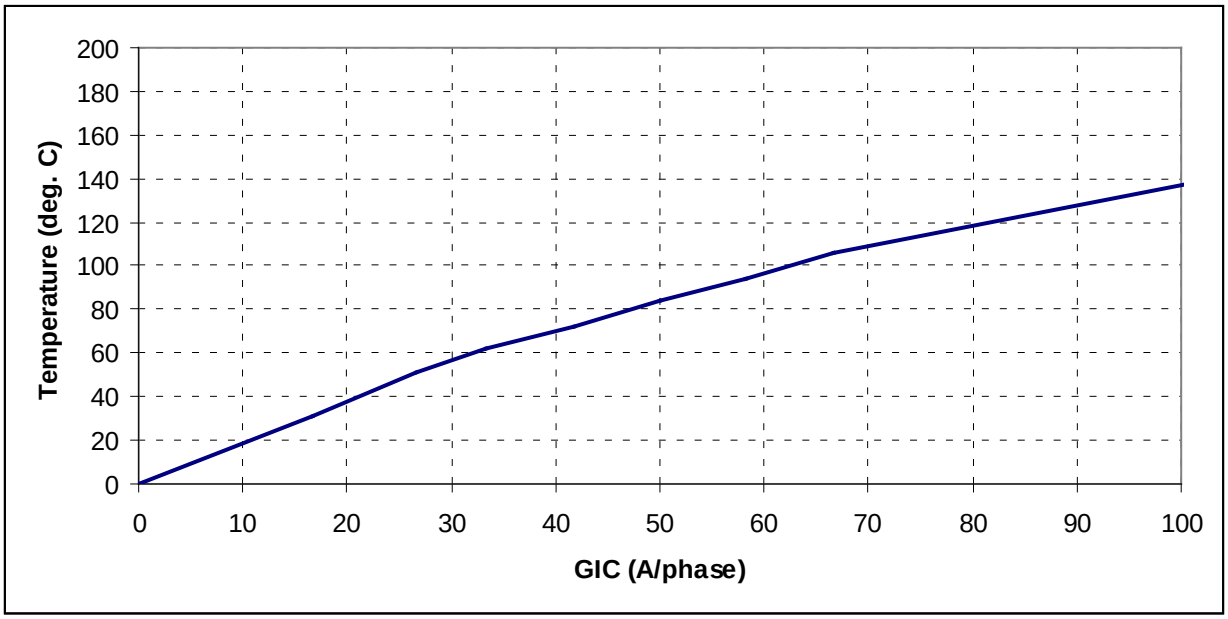


Figure 5: Asymptotic thermal response of the top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer.

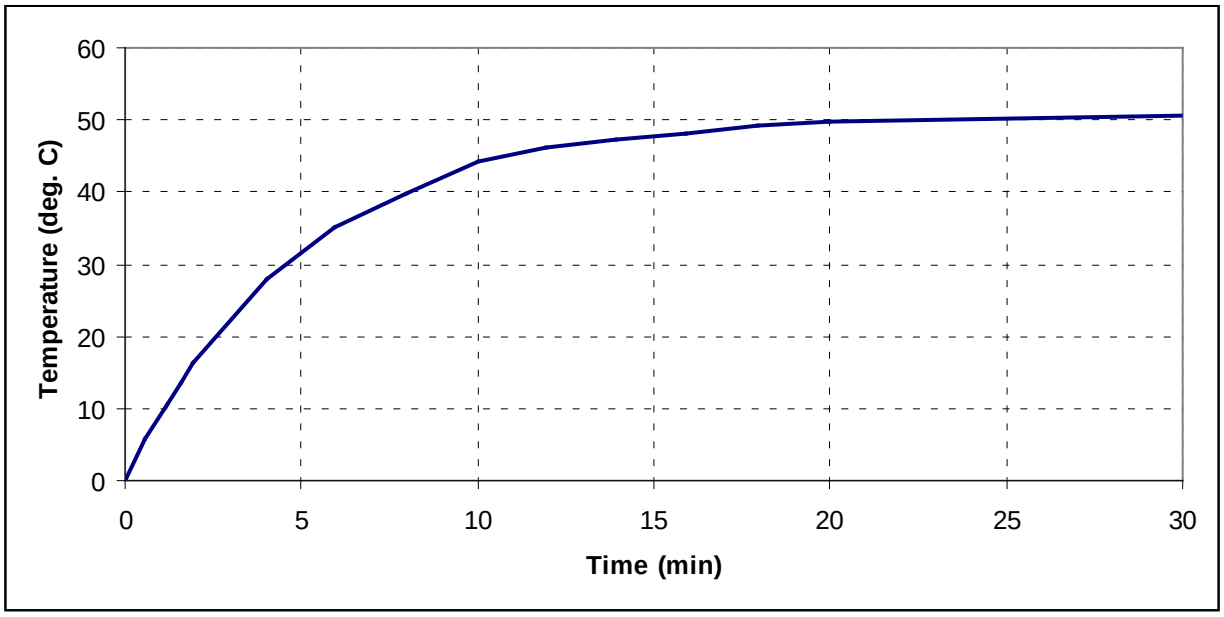


Figure 6: Step thermal response of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer to a 10 A per phase dc step.

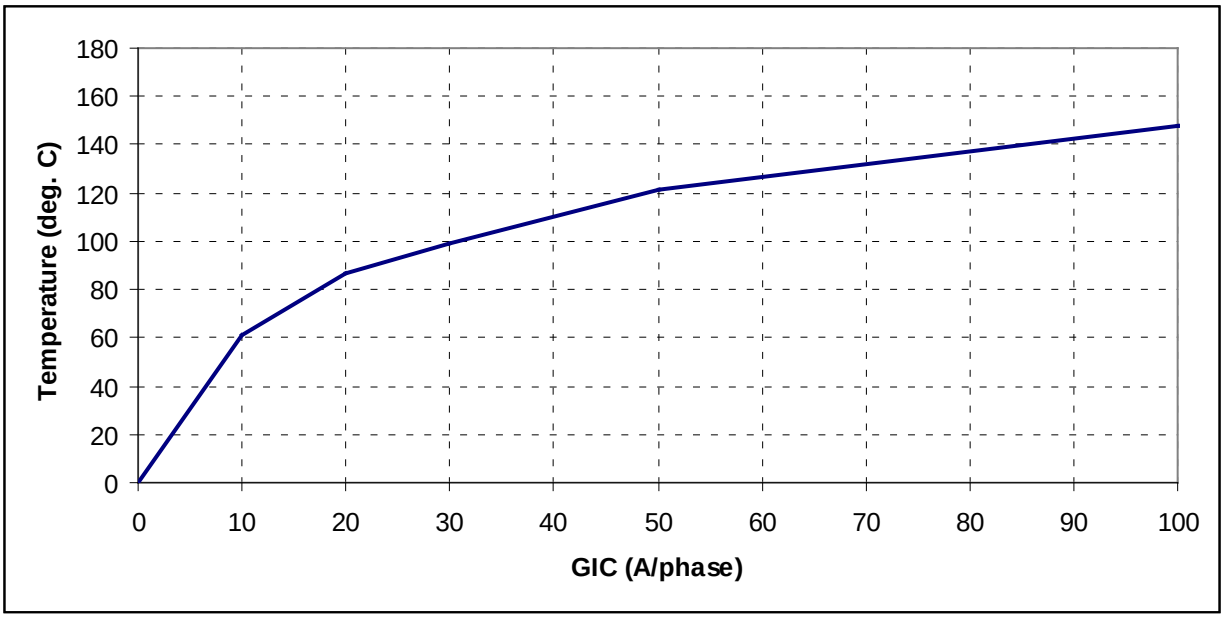


Figure 7: Asymptotic thermal response of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer.

The envelope in **Figure 1** can be used as a conservative thermal assessment for effective GIC values of 75 A per phase and greater (see Table 2).

Table 2: 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

For instance, if effective GIC is 130 A per phase and oil temperature is assumed to be 80°C, peak hot spot temperature is 193°C. This value is below the 200°C IEEE Std C57.91-2011 threshold for short time emergency loading and this transformer will have passed the thermal assessment. If the full heat run oil temperature is 67°C at maximum ambient temperature, then 150 A per phase of effective GIC translates into a peak hot spot temperature of 200°C and the transformer will have passed. If the limit is lowered to 180°C to account for the condition of the transformer, then this would be an indication to "sharpen the pencil" and perform a detailed assessment. Some methods are described in Reference [1].

The temperature envelope in Figure 1 corresponds to the values of effective GIC that result in the highest temperature for the benchmark GMD event. Different values of effective GIC could result in lower temperatures using the same model. For instance, the difference in upper and lower bounds of peak temperatures for the SVC coupling transformer model for 150 A per phase is approximately 30°C. In this case, GIC(t) should be generated to calculate the peak temperatures for the actual configuration of the transformer within the system as described in Reference [1]. Alternatively, a more precise thermal assessment could be carried out with a thermal model that more closely represents the thermal behavior of the transformer under consideration.

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Transformer Thermal Impact Assessment White Paper

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 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.

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.

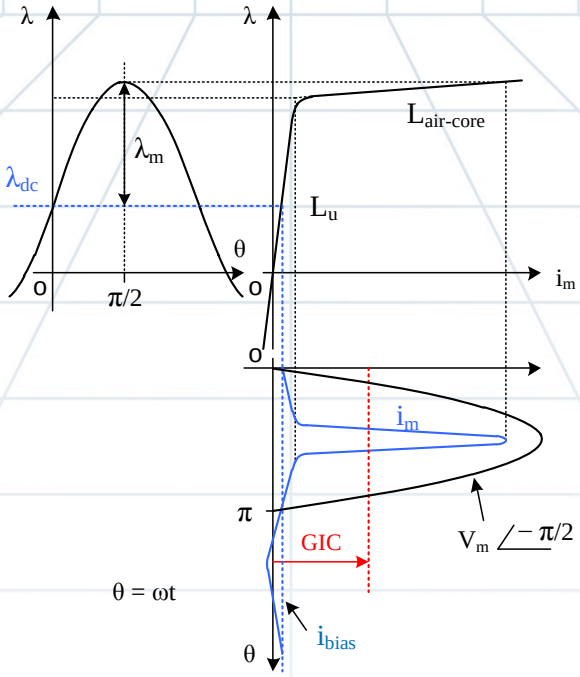


Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

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] for hot spot heating during short-term emergency operation. 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 "waveshape" 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 2 from the "Screening Criterion for Transformer Thermal Impact Assessment" white paper [7]. This table, shown as Table 1 below, provides the peak metallic hot spot temperatures that can be reached using conservative thermal models. To use Table 1, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after 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.

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

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)[1] or International Council on Large Electric Systems (CIGRE) may also provide technically justified methods for performing thermal assessments. All thermal assessment methods should be demonstrably equivalent to assessments that use the benchmark GMD event.

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 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. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC waveshape is equivalent to, for example, a 2 minute pulse. Also, manufacturers generally maintain that in

[1] For instance, IEEE Std C57.163-2015 Guide for Establishing Power Transformer Capability while under Geomagnetic Disturbances

the absence of transformer standards defining thermal duty due to GIC, such capability curves must be developed for every transformer design and vintage.

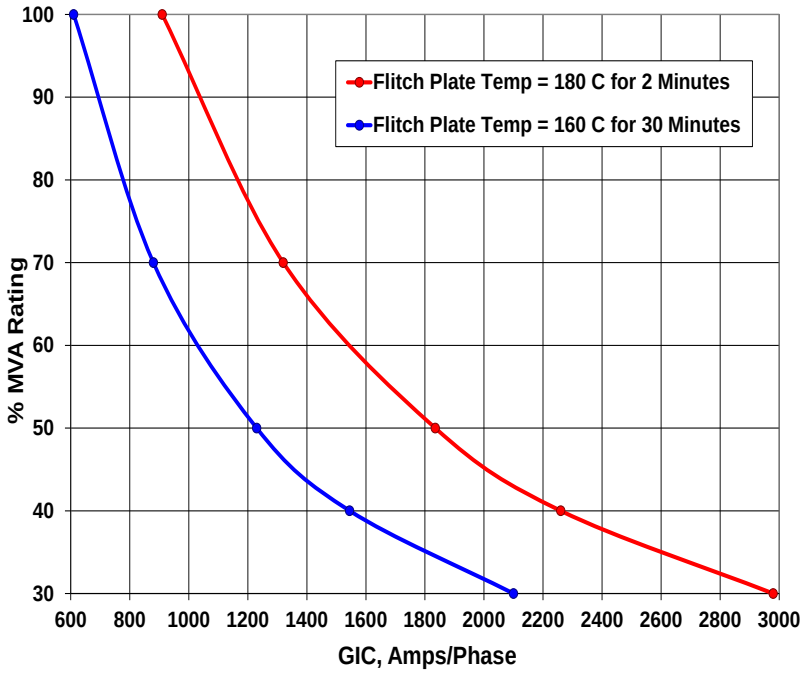


Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[2]. The input to this type of simulation is the time series or waveshape 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] 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]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[2] Technical details of this methodology can be found in [4].

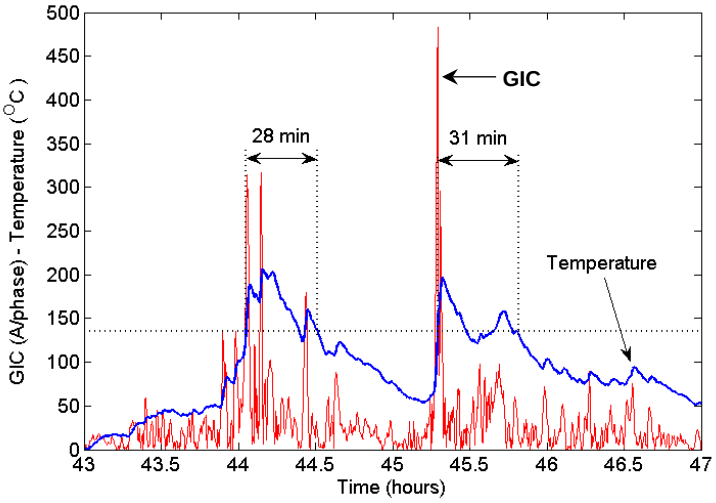


Figure 3: Sample Tie Plate Temperature Calculation
Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" 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 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].

$$GIC(t) = \left|E(t)\right| \cdot \left\{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\right\} \quad (2)$$

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/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] after the appropriate geomagnetic latitude scaling factor α is applied[3]. 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 conductivity scaling factor β[4]. 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]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)} \quad (6)$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)} \quad (7)$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

[3] 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.

[4] 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.

It should be emphasized that even for the same reference event, the GIC(t) waveshape 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 to test all transformers is incorrect.

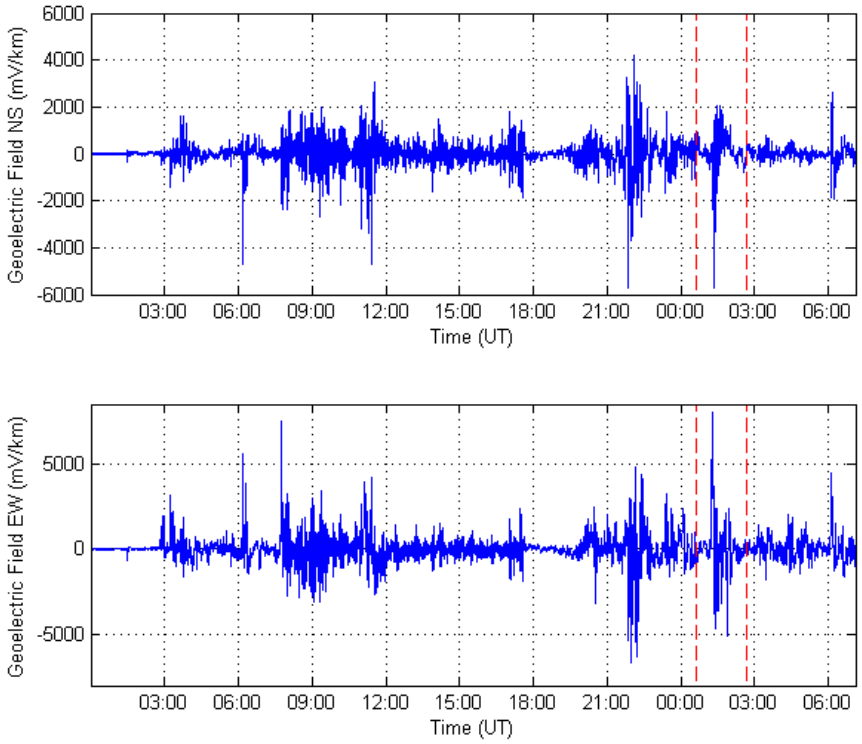


Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

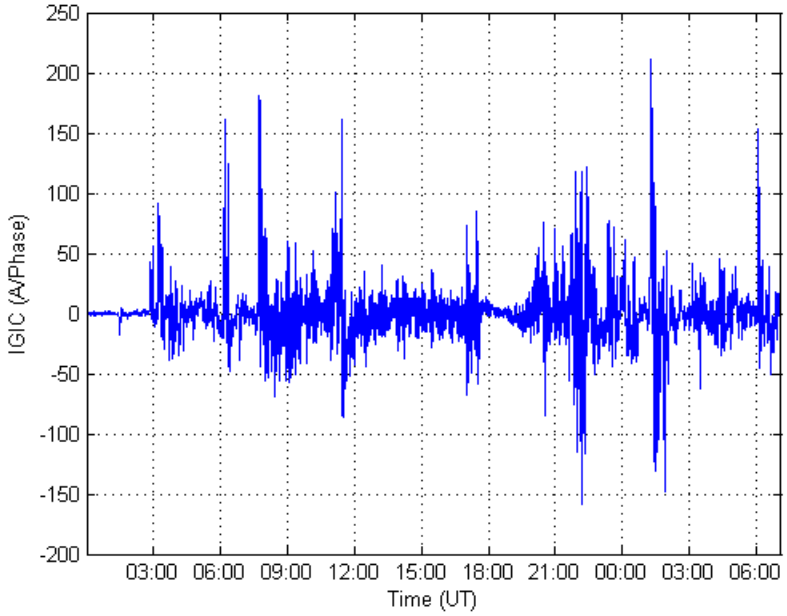


Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

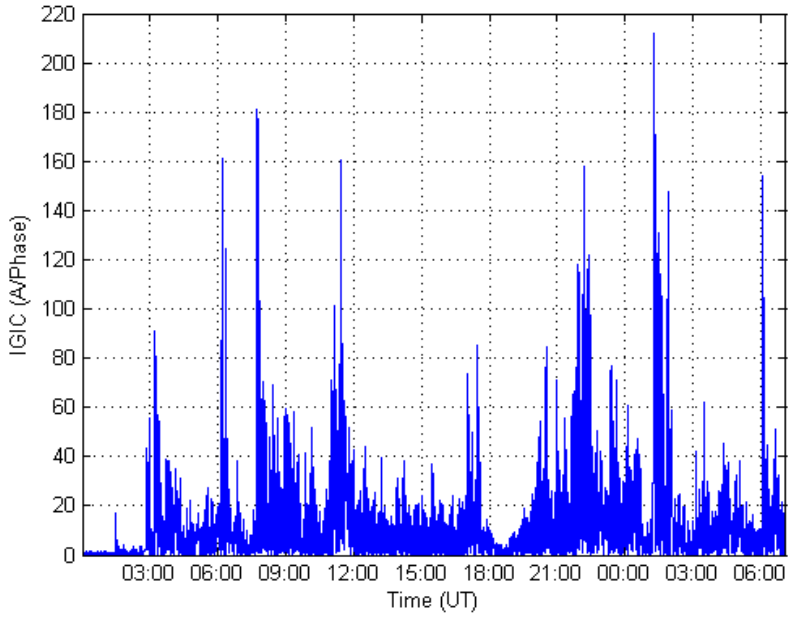


Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

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] 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.[5]

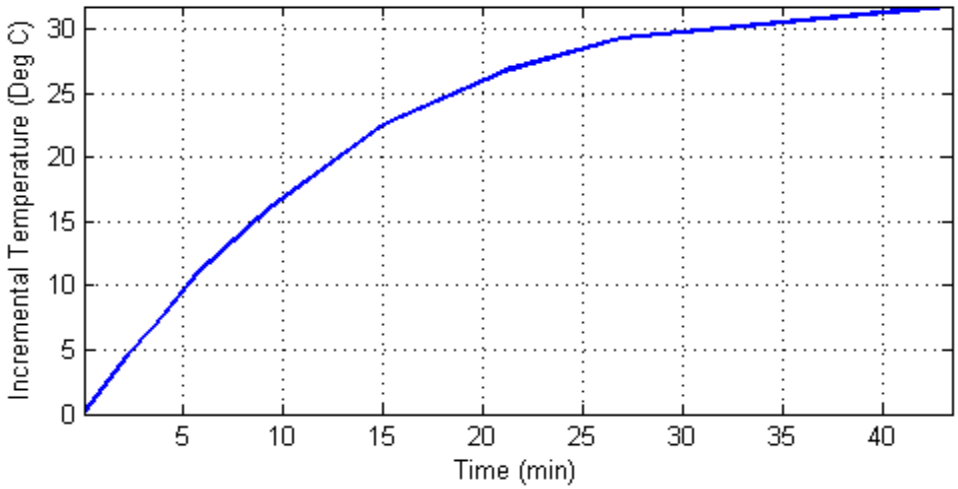


Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step
Metallic hot spot heating.

[5] 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.

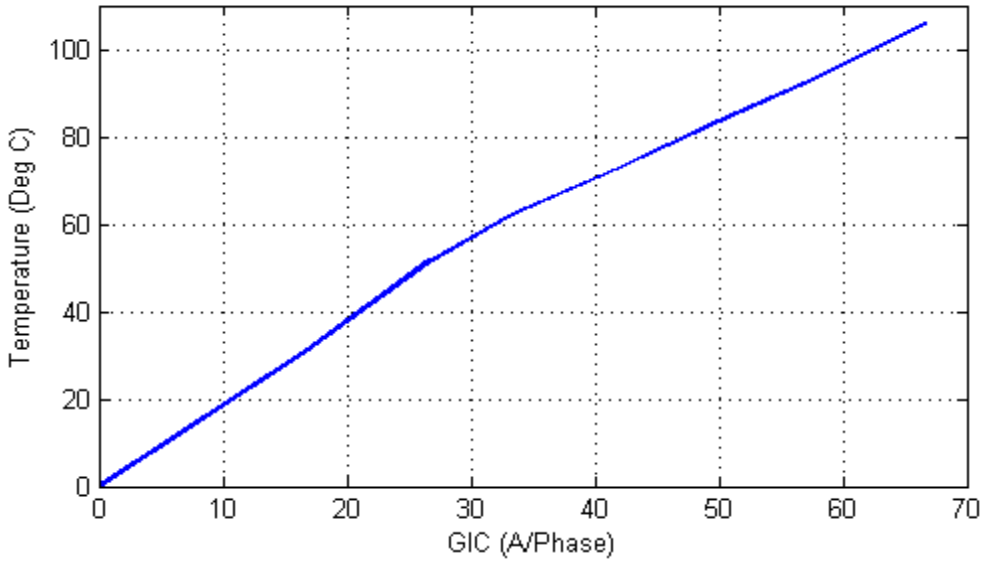


Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

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.

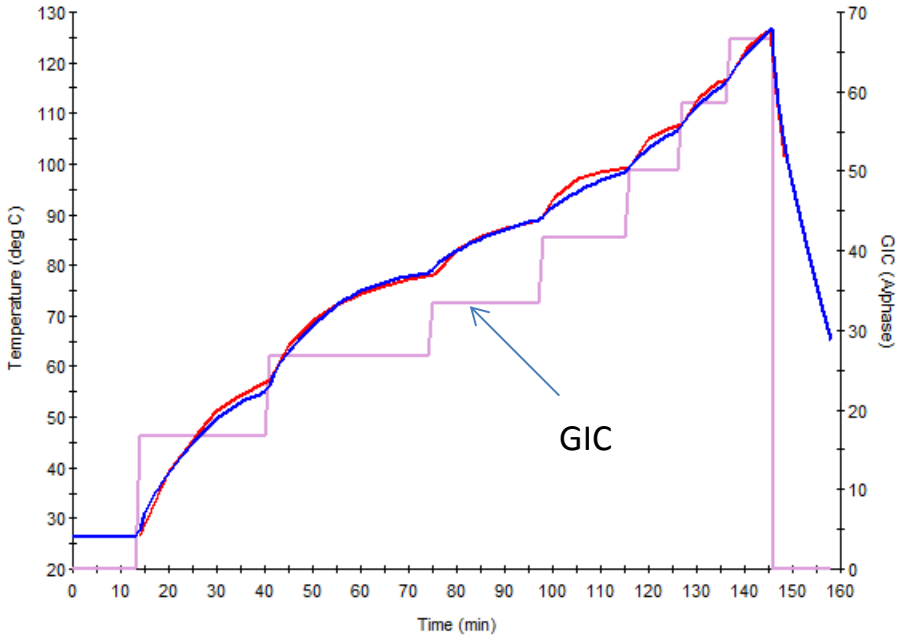


Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). Injected current is represented by the magenta trace.

To obtain the thermal response of the transformer to a GIC waveshape 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 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. 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 hot spot temperature time series $\theta(t)$. **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

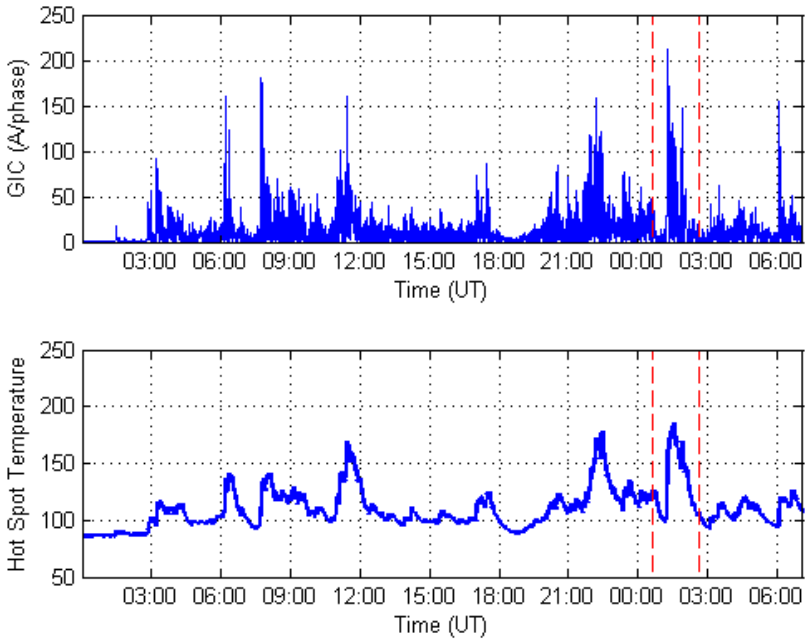


Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature $\theta(t)$ Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

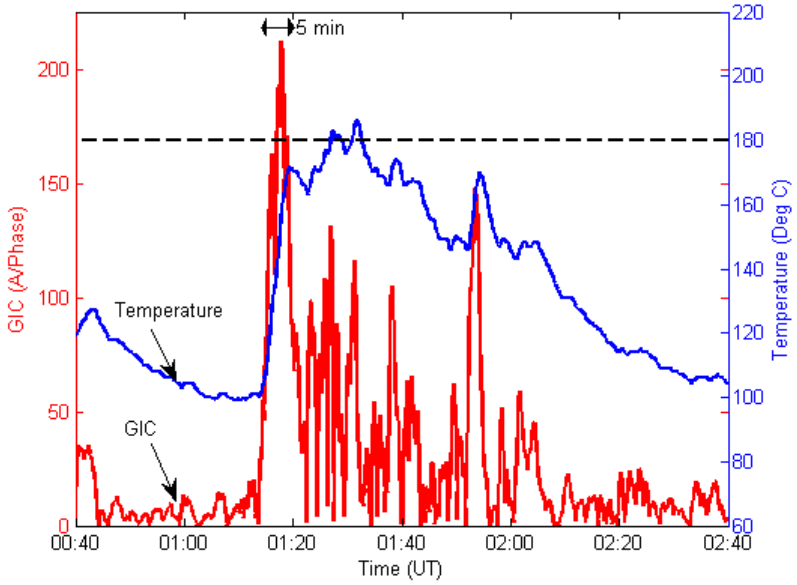


Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std C57.91 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.

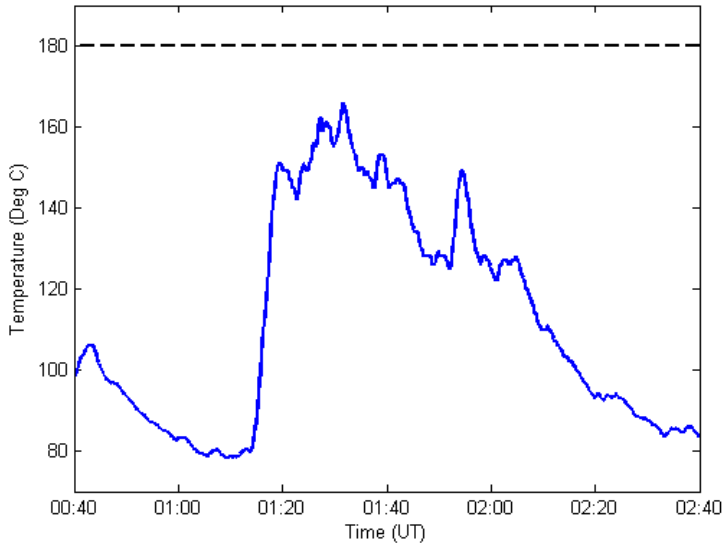


Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

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).

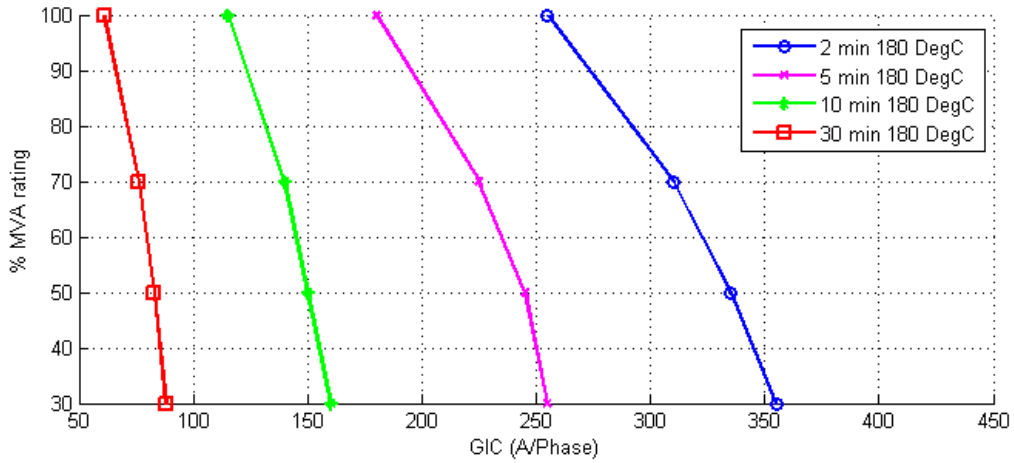


Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

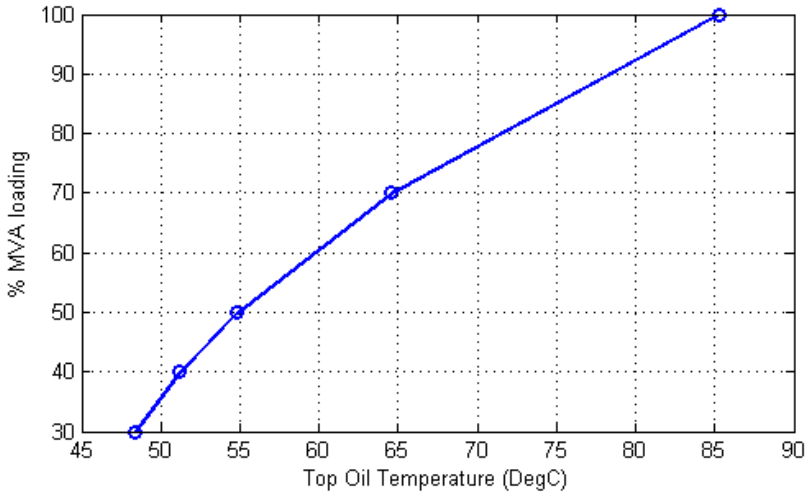


Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

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 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.

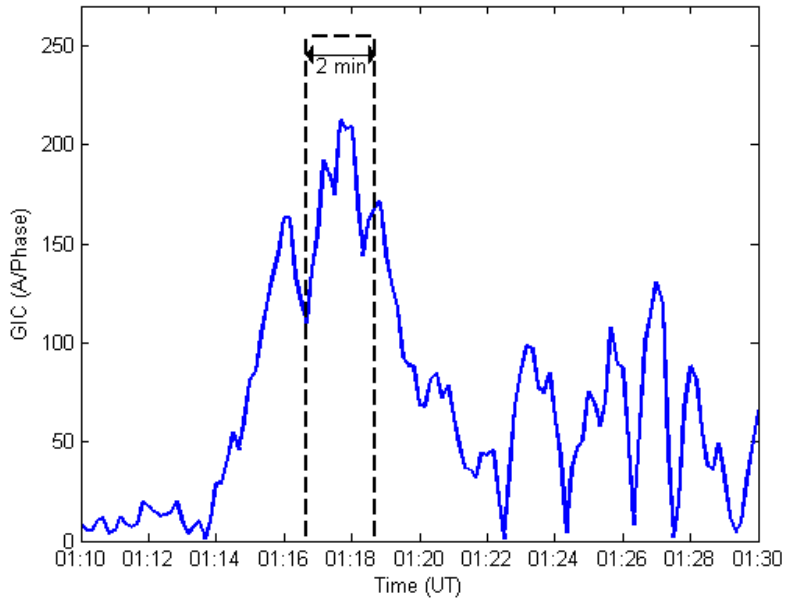


Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

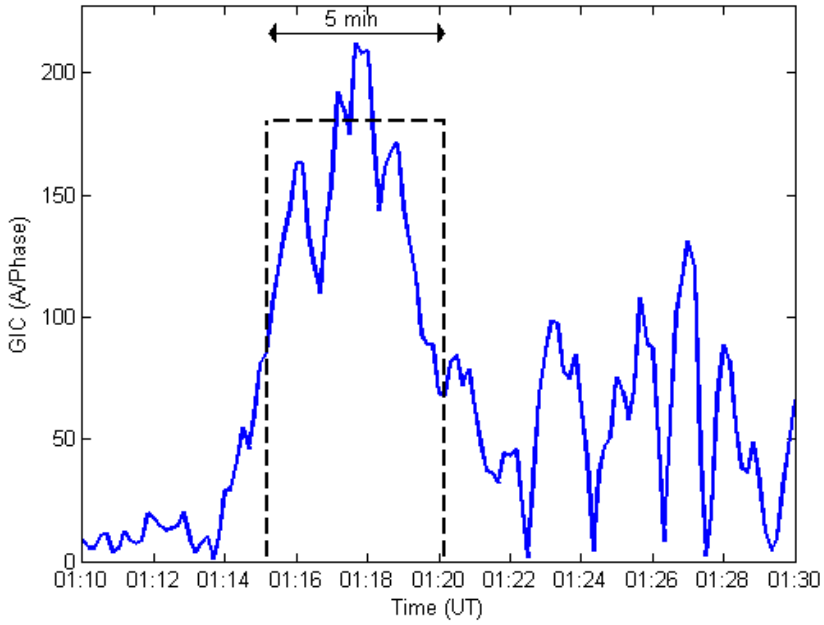


Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

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 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.

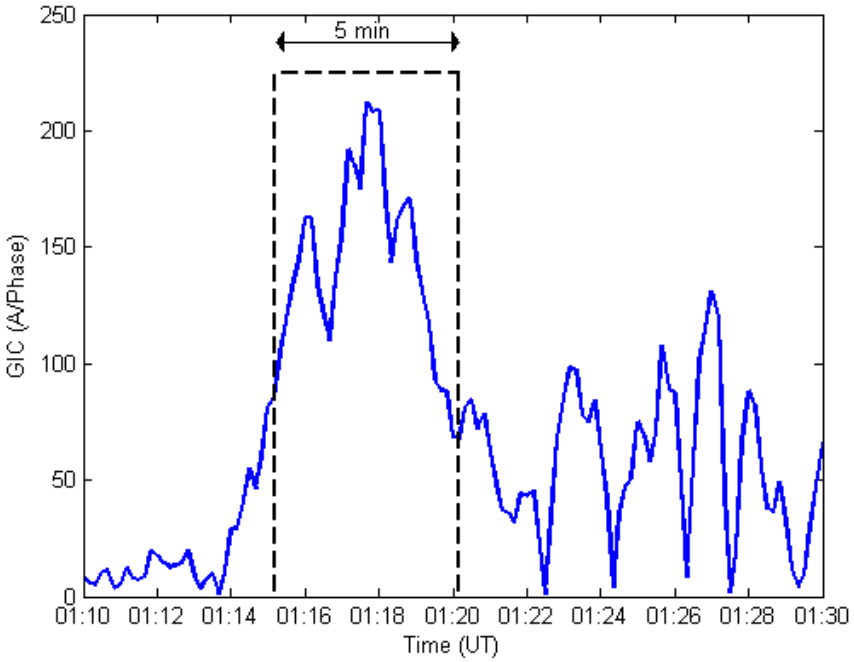


Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

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] 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] 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] 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/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] 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] "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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transformer Thermal Impact Assessment White Paper

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 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.

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.

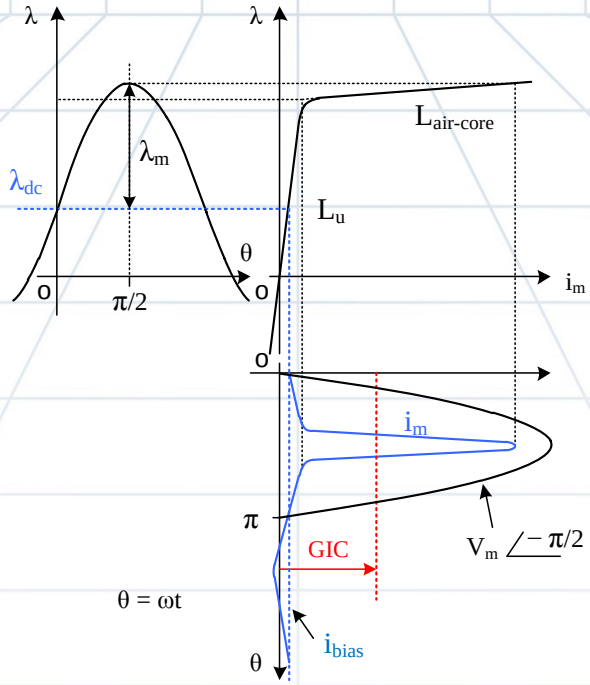


Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.

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] for hot spot heating during short-term emergency operation. 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 "waveshape" 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 2 from the "Screening Criterion for Transformer Thermal Impact Assessment" white paper [7]. This table, shown as Table 1 below, provides the peak metallic hot spot temperatures that can be reached using conservative thermal models. To use Table 1, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after 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.

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

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)[1] or International Council on Large Electric Systems (CIGRE) may also provide technically justified methods for performing thermal assessments. All thermal assessment methods should be demonstrably equivalent to assessments that use the benchmark GMD event.

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 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. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC waveshape is equivalent to, for example, a 2 minute pulse. Also, manufacturers generally maintain that in

[1] For instance, IEEE Std C57.163-2015 Guide for Establishing Power Transformer Capability while under Geomagnetic Disturbances

the absence of transformer standards defining thermal duty due to GIC, such capability curves must be developed for every transformer design and vintage.

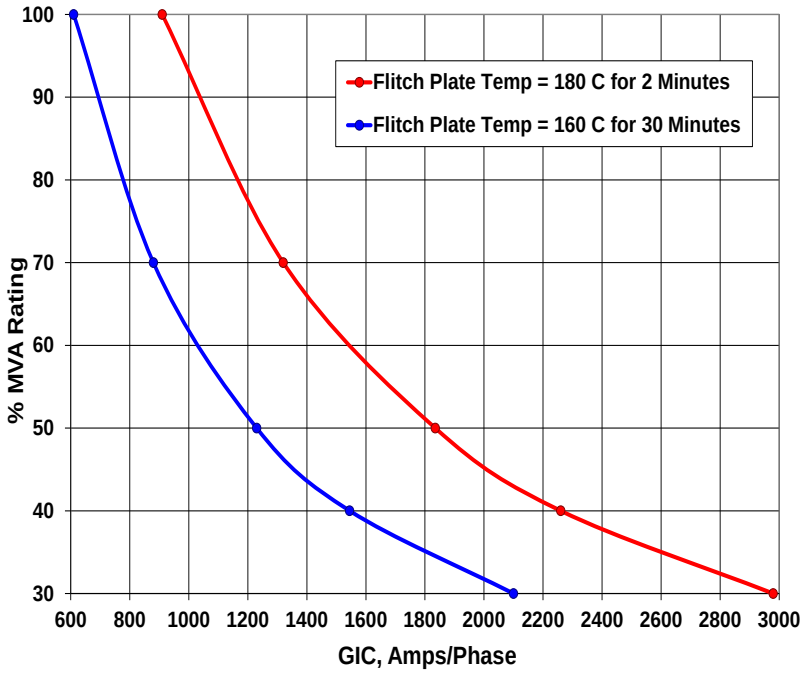


Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[2]. The input to this type of simulation is the time series or waveshape 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] 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]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[2] Technical details of this methodology can be found in [4].

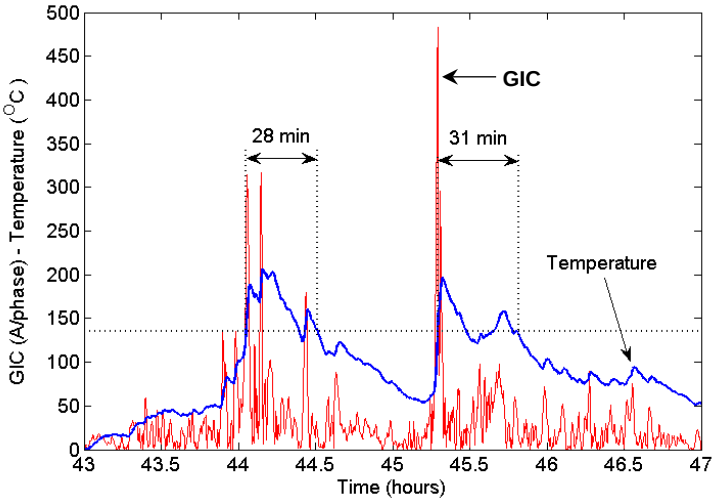


Figure 3: Sample Tie Plate Temperature Calculation
Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" 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 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/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] after the appropriate geomagnetic latitude scaling factor α is applied[3]. 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 conductivity scaling factor β[4]. 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]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)} \quad (6)$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)} \quad (7)$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

[3] 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.

[4] 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.

It should be emphasized that even for the same reference event, the GIC(t) waveshape 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 to test all transformers is incorrect.

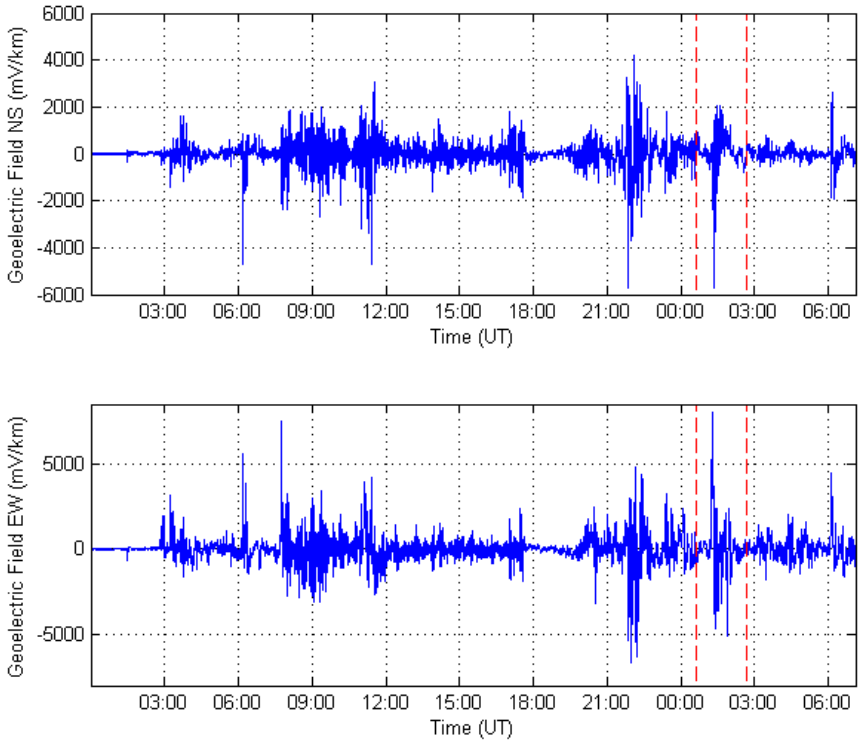


Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

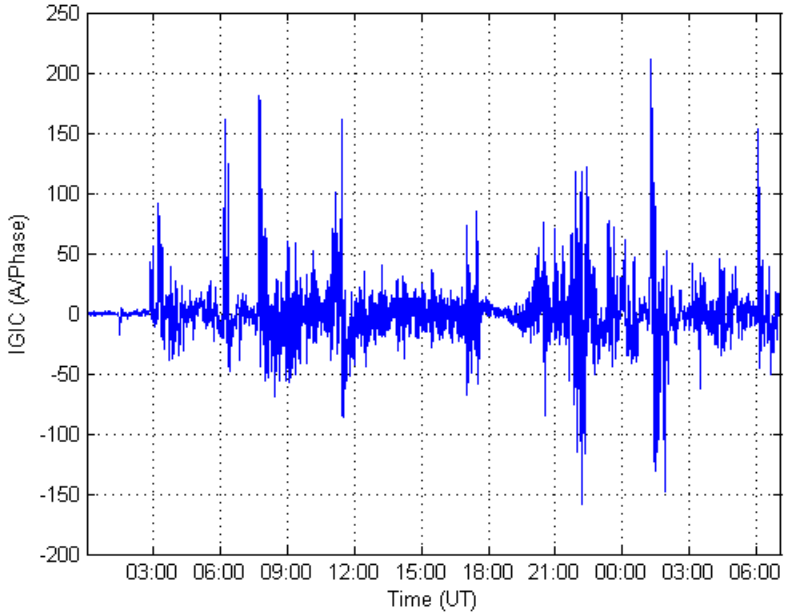


Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

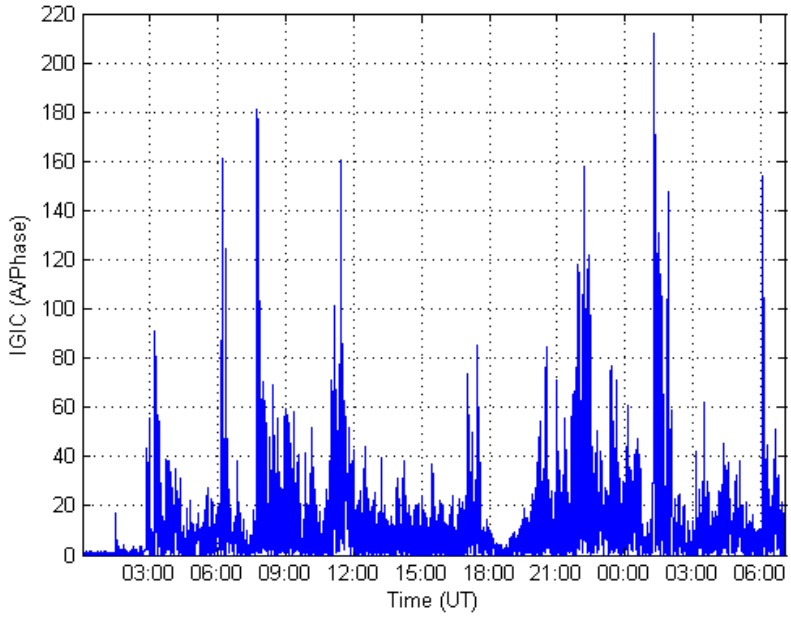


Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

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] 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.[5]

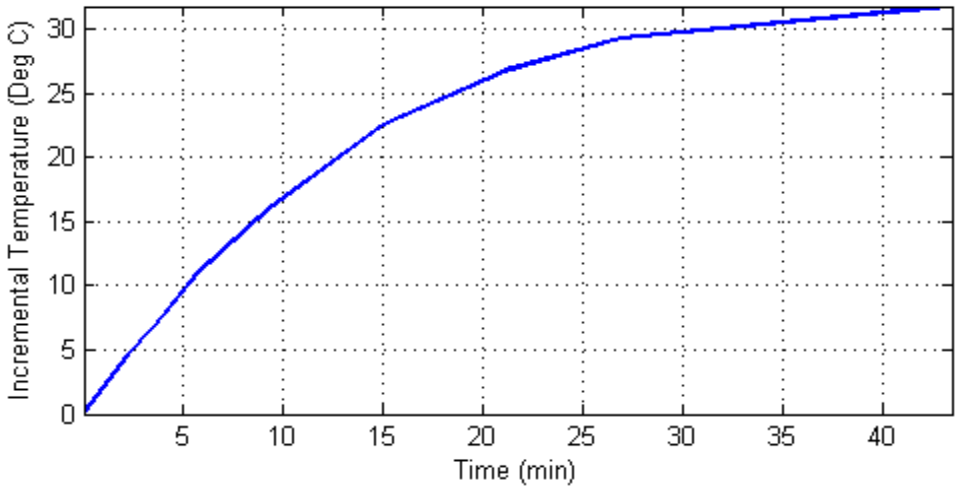


Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step
Metallic hot spot heating.

[5] 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.

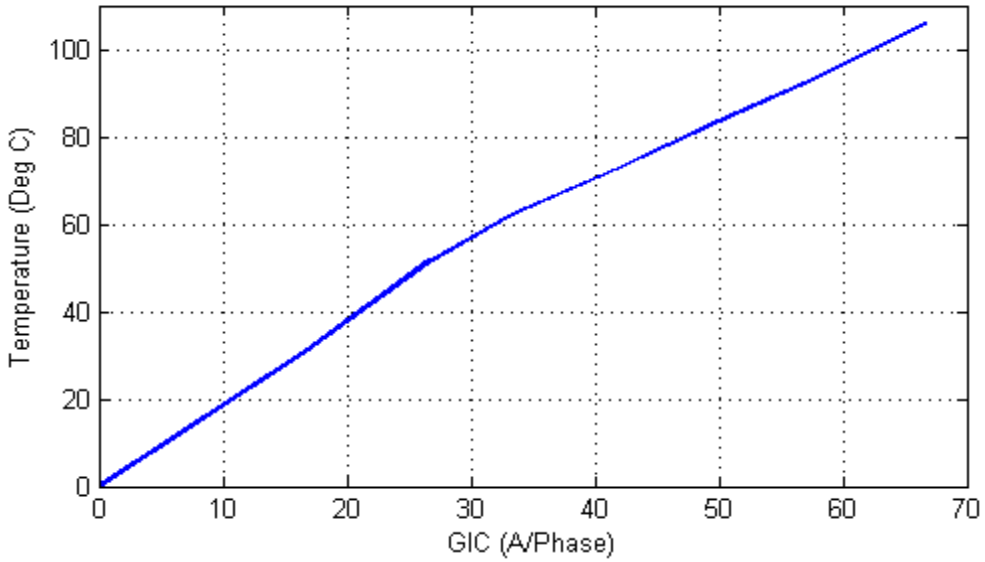


Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

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.

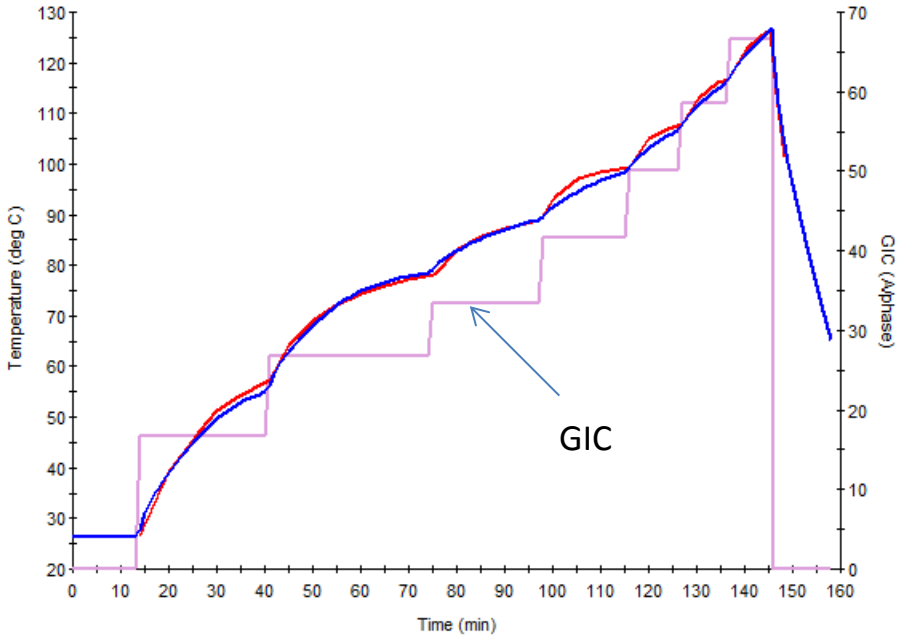


Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). Injected current is represented by the magenta trace.

To obtain the thermal response of the transformer to a GIC waveshape 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 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. 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 hot spot temperature time series $\theta(t)$. **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

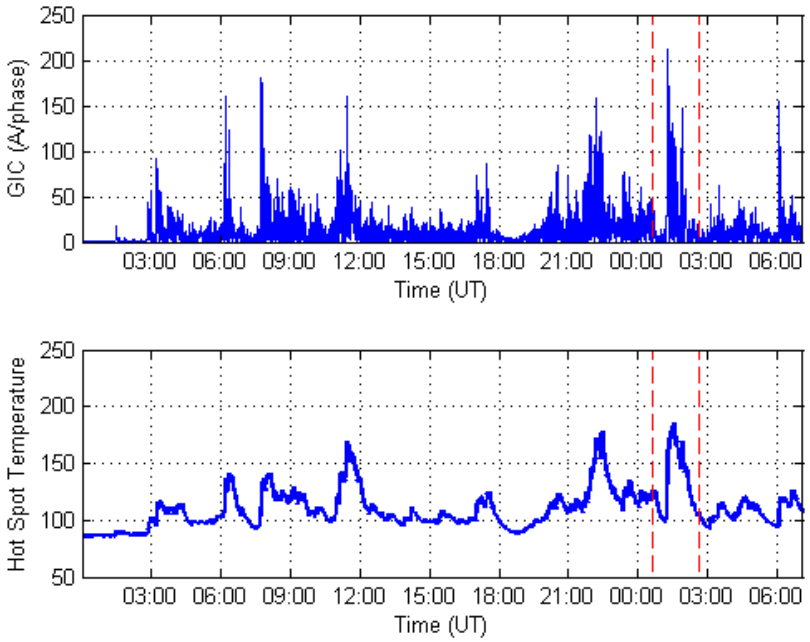


Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature $\theta(t)$ Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

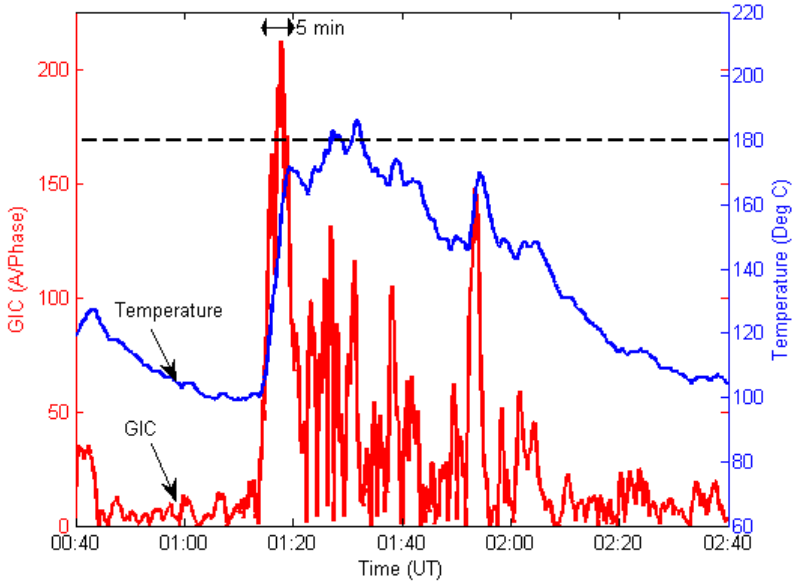


Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std C57.91 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.

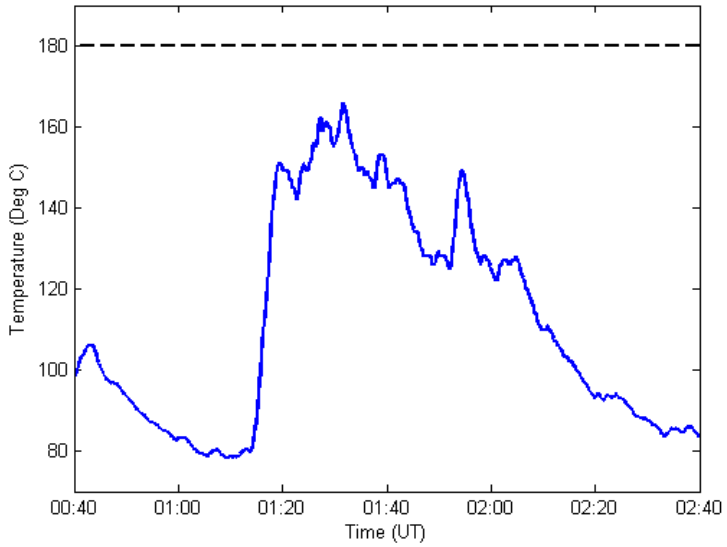


Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

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).

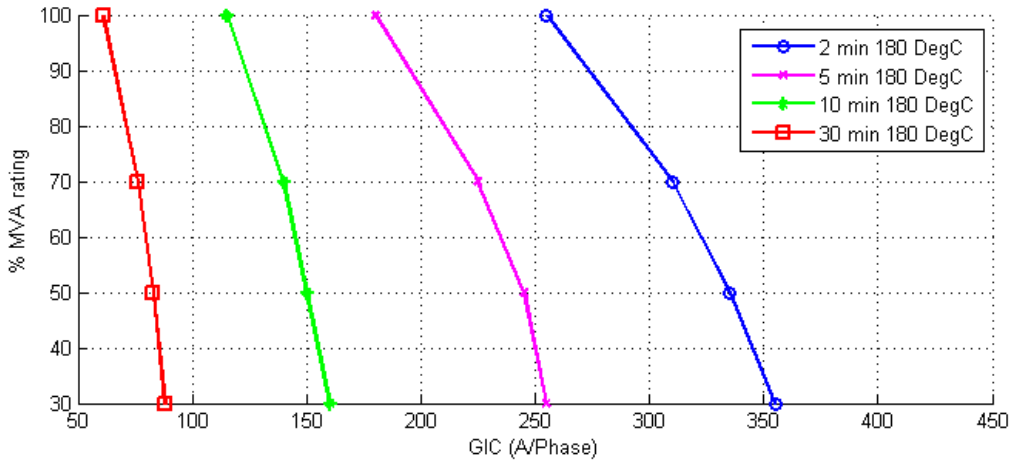


Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

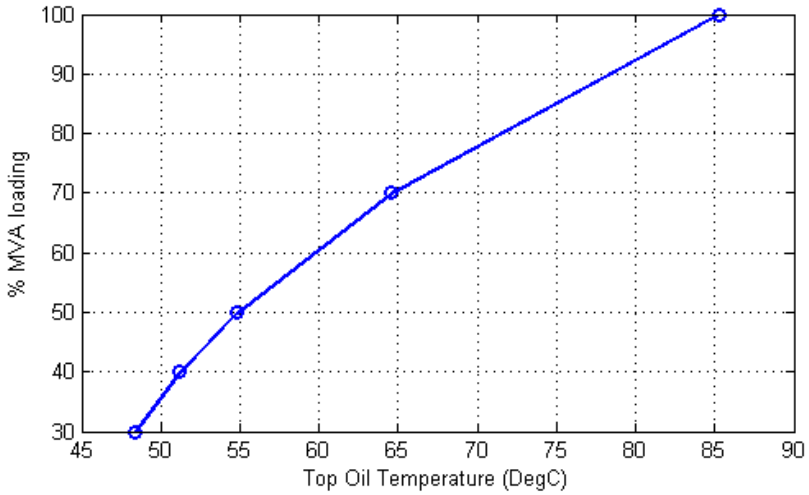


Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

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 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.

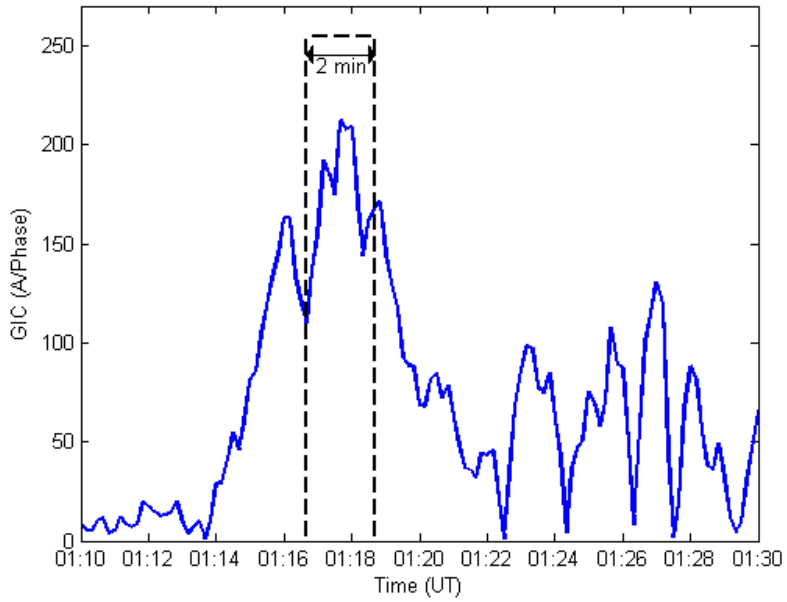


Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

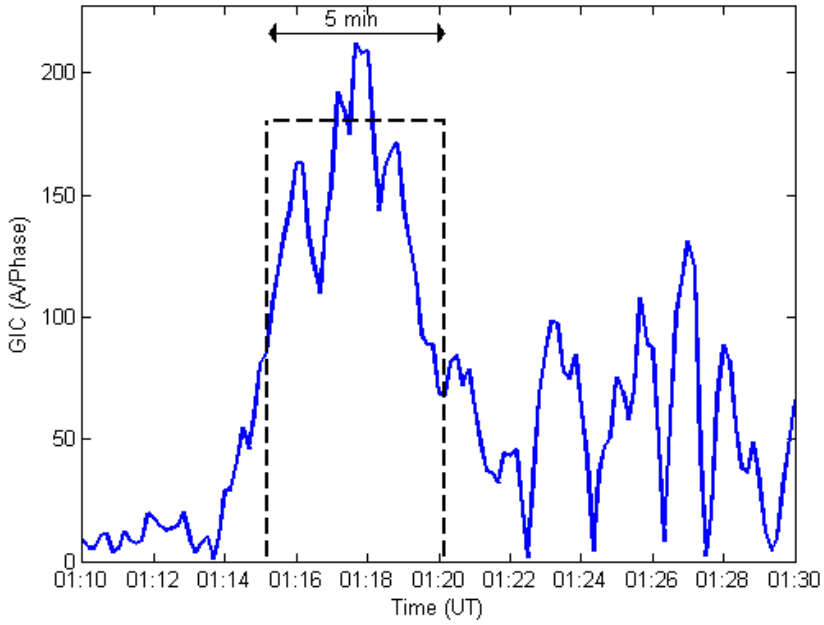


Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

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 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.

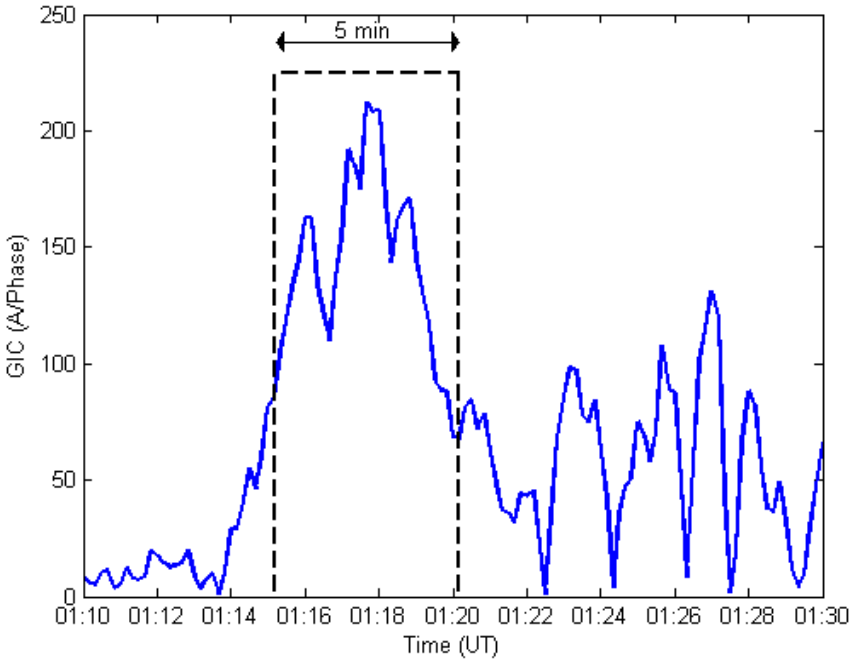


Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

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] 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] 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] 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/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] 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] "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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Meeting Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation Standard Drafting Team

May 11, 2016 | 8:00 – 10:00 a.m. Eastern

Conference Call with Web Access

ReadyTalk Webinar | Enter Access Code: 6251541

Dial-in: 1-866-740-1260 | Access Code: 6251541 | Security Code: 201303

The purpose of this web meeting is to review and discuss a correction to the *Screening Criterion for Transformer Thermal Impact Assessment* white paper related to the proposed TPL-007-1 reliability standard. The proposed standard and related white papers are available on the project page.

For more information or assistance, contact Senior Standards, Mark Olson (via email) or by phone at (404) 446-9760.

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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Standards Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation | Revised White Papers

Comment Period Open through June 13, 2016

Now Available

A comment period is open for **Project 2013-03 Geomagnetic Disturbance Mitigation** revised white papers. Stakeholders may provide comments using the link below through **8 p.m. Eastern, Monday, June 13, 2016.**

The standards drafting team (SDT) identified an error in Figure 1 of the *Screening Criterion for Transformer Thermal Impact Assessment* white paper (Screening Criterion white paper). The error resulted in incorrect plotting of simulated power transformer peak hot-spot heating from the Benchmark GMD Event. The SDT has corrected Figure 1 and revised related sections in the Screening Criterion white paper. The SDT has also made related revisions to other Project 2013-03 white papers. The revisions do not affect requirements in proposed TPL-007-1 but are being incorporated into the project white papers to maintain accuracy.

Commenting

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

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email) or by phone at (404) 446-9760.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Meeting Announcement

Project 2013-03 Geomagnetic Disturbance Mitigation Standard Drafting Team

June 24, 2016 | 8:30 – 10:30 a.m. Eastern

Conference Call with Web Access

ReadyTalk Webinar | Enter Access Code: 6251541

Dial-in: 1-866-740-1260 | Access Code: 6251541 | Security Code: 201303

The Standard Drafting Team (SDT) will review and discuss stakeholder comments and recommendations on the white papers associated with proposed reliability standard TPL-007-1. In May, the SDT corrected Figure 1 of the *Screening Criterion for Transformer Thermal Impact Assessment* white paper, and made corresponding revisions to text in the project white papers. The revisions were posted on May 13, 2016, for a 30-day comment period. Proposed standard TPL-007-1 and related white papers are available on the project page.

For more information or assistance, contact Senior Standards Developer, Mark Olson (via email) or by phone at (404) 446-9760.

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20160623-3025 FERC PDF (Unofficial) 06/23/2016

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD16-5-000

June 23, 2016

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Shamai Elstein
Senior Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation for Approval of the Revised Definition of Special Protection System

Dear Mr. Elstein:

On May 11, 2016, the North American Electric Reliability Corporation (NERC) filed a petition for Commission approval, pursuant to section 215(d)(1) of the Federal Power Act (FPA)[1] and Section 39.5 of the Commission's regulations[2] of proposed revised definition of "Special Protection System" (SPS) in the *Glossary of Terms Used in NERC Reliability Standards* (Glossary). NERC also seeks approval of the proposed implementation plan and the retirement of the currently-effective SPS definition.

In its petition, NERC states that the NERC Glossary definition for Remedial Action Scheme (RAS) is a cross-reference to the definition of the term "Special Protection System" and reads: "See 'Special Protection System."[3] In Project 2010-05.2, NERC revised the definition of RAS which was approved by the Commission in Order

[1] 16 U.S.C. § 824o (2012).

[2] 18 C.F.R. § 39.5 (2015).

[3] NERC Petition at 7.

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No. 818.[4] The revised definition of RAS "adds clarity and granularity that will allow for proper identification of Remedial Action Schemes and a more consistent application of related Reliability Standards."[5]

In its petition, NERC explains that given Commission approval of the revised definition of RAS and the continued, inconsistent usage the terms "Remedial Action Scheme" and "Special Protection System," it has revised the definition of SPS to refer to the Commission-approved revised definition for RAS. This proposed definition, which states "See Remedial Action Scheme," will ensure that any reference to either SPS or RAS refers to the revised definition of RAS approved by the Commission on November 19, 2015.[6]

NERC also explains that, per its implementation plan, the proposed effective date is "on the later of the effective date of the applicable governmental authority's order approving the revised definition of Special Protection System or the effective date of the revised definition of Remedial Action Scheme approved by the Commission on November 19, 2015." The proposed effective date ensures that all references to either term in NERC or Regional Entity documents invoke the revised definition of RAS approved by the Commission on November 19, 2015.[7]

NERC's filing was noticed on May 11, 2016, with interventions, comments and protests due on or before June 10, 2016. No interventions, comments or protests were received.

NERC's uncontested petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2015), effective as of the date of this order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by

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[4] *Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, Order No. 818, 153 FERC ¶ 61,228 (2015).

[5] *Id.* P 23.

[6] NERC Petition at 11.

[7] *Id.*

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the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2015).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

Document Content(s)

DLO_RD16-5.DOCX.....1-3

156 FERC ¶ 61,017
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Availability of Certain North American Electric Reliability Corporation Databases to the Commission	Docket No. RM15-25-000

ORDER CLARIFYING EFFECTIVE DATE AND COMPLIANCE DATE

July 7, 2016

1. In Order No. 824, the Commission issued a final rule amending its regulations, pursuant to section 215 of the Federal Power Act (FPA),[1] to require the North American Electric Reliability Corporation (NERC) to provide the Commission, and Commission staff, with access, on a non-public and ongoing basis, to certain databases compiled and maintained by NERC.[2] The Commission directed that "[t]his rule will become effective upon issuance of the final rule in Docket No. RM16-15-000."[3]

2. To conform with Federal Register guidelines, the Commission clarifies the final rule's effective date and compliance date as follows:

> *Effective date:* This rule will become effective [**INSERT DATE of publication in the FEDERAL REGISTER**].

[1] 16 U.S.C. § 824o (2012).

[2] *Availability of Certain North American Electric Reliability Corporation Databases to the Commission*, Order No. 824, 155 FERC ¶ 61,275 (June 16, 2016).

[3] *Id.* P 75.

Compliance date: The compliance date is based on issuance of the final rule in Docket No. RM16-15-000. The Commission will publish a document in the Federal Register announcing the compliance date.

This clarification conforms the Database Final Rule to the Commission's stated intent of deferring Commission access to the databases "until the Commission issues a final rule adopting regulations to implement its recently-expanded authority to protect against the disclosure of 'critical electric infrastructure information.'"[4]

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

[4] *Id.* P 46.

156 FERC ¶ 61,051
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM16-18-000

Cyber Systems in Control Centers

(Issued July 21, 2016)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Inquiry.

SUMMARY: In this Notice of Inquiry, the Federal Energy Regulatory Commission seeks comment on possible modifications to the Critical Infrastructure Protection Reliability Standards regarding the cybersecurity of Control Centers used to monitor and control the bulk electric system in real time.

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

ADDRESSES: You may submit comments, identified by docket number and in accordance with the requirements posted on the Commission's website, http://www.ferc.gov. Comments may be submitted by any of the following methods:

- Agency Website: Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format, at http://www.ferc.gov/docs-filing/efiling.asp.

- Mail/Hand Delivery: Those unable to file electronically must mail or hand deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

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

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SUPPLEMENTARY INFORMATION:

156 FERC ¶ 61,051
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Cyber Systems in Control Centers Docket No. RM16-18-000

NOTICE OF INQUIRY

(Issued July 21, 2016)

1. In this Notice of Inquiry, pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission seeks comment on the need for, and possible effects of, modifications to the Critical Infrastructure Protection (CIP) Reliability Standards regarding the cybersecurity of Control Centers used to monitor and control the bulk electric system in real time.[2] Cyber systems are used extensively for the operation and maintenance of interconnected transmission networks.[3] A 2015 cyberattack on the electric grid in

[1] 16 U.S.C. 824o. Section 215(a)(3) of the FPA defines "Reliability Standard" to include "…requirements for the operation of existing bulk-power system facilities, including cybersecurity protection…"

[2] NERC defines "Control Center" as "[o]ne 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…." NERC Glossary of Terms Used in Reliability Standards (May 17, 2016) at 33 (NERC Glossary).

[3] Cyber systems are referred to as "BES Cyber Systems" in the CIP Reliability Standards. The NERC Glossary defines BES Cyber Systems as "One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity." NERC Glossary at 15. The NERC Glossary defines "BES Cyber Asset" as "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,

(continued…)

Ukraine is an example of how cyber systems used to operate and maintain interconnected networks, unless adequately protected, may be vulnerable to cyberattack. While certain controls in the CIP Reliability Standards may reduce the risk of such attacks,[4] the Commission seeks comment on whether additional controls should be required.

2. Specifically, as discussed below, the Commission seeks comment on possible modifications to the CIP Reliability Standards - and any potential impacts on the operation of the Bulk-Power System resulting from such modifications - to address the following matters: (1) separation between the Internet and BES Cyber Systems in Control Centers performing transmission operator functions; and (2) computer administration practices that prevent unauthorized programs from running, referred to as "application whitelisting," for cyber systems in Control Centers.

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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." *Id.*

[4] *See, e.g.*, Reliability Standard CIP-005-5 (Electronic Security Perimeter(s)), Requirement R2, which protects against unauthorized interactive remote access; Reliability Standard CIP-006-6 (Physical Security of BES Cyber Systems), Requirement R2, which protects against unauthorized physical access and Reliability Standard CIP-007-6 (System Security Management), Requirement R3, which protects against malware.

I. Background

3. On January 28, 2008, the Commission approved an initial set of eight CIP Reliability Standards pertaining to cybersecurity.[5] In addition, the Commission directed NERC to develop certain modifications to the CIP Reliability Standards. Since 2008, the CIP Reliability Standards have undergone multiple revisions to address Commission directives and respond to emerging cybersecurity issues.

4. On December 23, 2015, three regional electric power distribution companies in Ukraine experienced a cyberattack resulting in power outages that affected at least 225,000 customers. An analysis conducted by a team from the Electricity Information Sharing and Analysis Center (E-ISAC) and SANS Industrial Control Systems (SANS ICS) observed that "the cyber attacks in Ukraine are the first publicly acknowledged incidents to result in power outages."[6]

5. On February 25, 2016, the U.S. Department of Homeland Security (DHS) Industrial Control Systems Cyber Emergency Response Team issued an "Alert" in

[5] *Mandatory Reliability Standards for Critical Infrastructure Protection*, Order No. 706, 122 FERC ¶ 61,040, *denying reh'g and granting clarification*, Order No. 706-A, 123 FERC ¶ 61,174 (2008), *order on clarification*, Order No. 706-B, 126 FERC ¶ 61,229 (2009), *order denying clarification*, Order No. 706-C, 127 FERC ¶ 61,273 (2009).

[6] E-ISAC, Analysis of the Cyber Attack on the Ukrainian Power Grid (March 18, 2016) at 3, http://www.nerc.com/pa/CI/ESISAC/Documents/E-ISAC_SANS_Ukraine_DUC_18Mar2016.pdf.

response to the Ukraine incident.[7] The Alert stated that the cyberattack was sophisticated and well planned. The Alert reported that the cyberattacks at each company occurred within 30 minutes of each other and affected multiple central and regional facilities. The Alert also explained that during the cyberattacks:

> malicious remote operation of the breakers was conducted by multiple external humans using either existing remote administration tools at the operating system level or remote industrial control system (ICS) client software via virtual private network (VPN) connections. The companies believe that the actors acquired legitimate credentials prior to the cyber-attack to facilitate remote access.

In addition, the Alert reported that the affected companies indicated that the attackers wiped some systems at the conclusion of the cyberattack, which erased selected files, rendering systems inoperable.

6. In response to the Ukraine incident, the Alert recommended the following key examples of best practice mitigation strategies:

> procurement and licensing of trusted hardware and software systems; knowing who and what is on your network through hardware and software asset management automation; on time patching of systems; and strategic technology refresh.[8]

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[7] *See* Department of Homeland Security, Alert (IR-ALERT-H-16-056-01) *Cyber-Attack Against Ukrainian Critical Infrastructure* (February 25, 2016) (Alert), https://ics-cert.us-cert.gov/alerts/IR-ALERT-H-16-056-01.

[8] *Id.* at Mitigation Section. By "strategic technology refresh," the Alert referred to the benefit of replacing legacy cyber systems that no longer receive security patches and, as a result, might not be secure.

II. Request for Comments

7. The Commission seeks comment on whether to modify the CIP Reliability Standards to better secure Control Centers from cyberattacks. The Commission also seeks comment on the potential consequences or complications arising from implementing such modifications. In response to lessons learned from the Alert and analyses of the Ukraine incident, the Commission seeks comment on whether to modify the CIP Reliability Standards to require: (1) separation between the Internet and BES Cyber Systems in Control Centers performing transmission operator functions; and (2) "application whitelisting" for BES Cyber Systems in Control Centers.

A. Isolation of Transmission Operator Control Centers from the Internet

8. In response to the Ukraine incident, the Alert recommended that:

> [o]rganizations should isolate [industrial control system] networks from any untrusted networks, especially the Internet. All unused ports should be locked down and all unused services turned off. If a defined business requirement or control function exists, only allow real-time connectivity to external networks. If one-way communication can accomplish a task, use optical separation ('data diode'). If bidirectional communication is necessary, then use a single open port over a restricted network path.

9. Commission-approved Reliability Standard CIP-007-6, Requirement R1 (Ports and Services), Part 1.1 requires, where technically feasible, unused logical ports to be disabled.[9] In addition, Reliability Standard CIP-007-6, Requirement R1, Part 1.2 requires

[9] Logical ports are connection points where two applications communicate to identify different applications or processes running on a cyber asset.

protection of physical ports against unnecessary use.[10] These requirements therefore address the Alert's recommendation that "[a]ll unused ports should be locked down and all unused services turned off."

10. The current CIP Reliability Standards do not require isolation between the Internet and BES Cyber Systems in Control Centers performing transmission operator functions through use of physical (hardware) or logical (software) means. Although BES Cyber Systems are protected by electronic security perimeters and the disabling of unused logical ports, BES Cyber Systems are permitted, within the scope of the current CIP Reliability Standards, to route, or connect, to the Internet.[11] Requiring physical separation between the Internet and cyber systems in Control Centers performing transmission operator functions would require data connections to Control Centers or other facilities owned by transmission operators over dedicated data lines owned or leased by the transmission operator, rather than allowing communications over the Internet.[12] Logical separation, in some contexts, can achieve a similar objective through different means.

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[10] A physical port serves as an interface or connection between a cyber asset and another cyber asset, or peripheral device, using a physical medium such as a cable.

[11] NERC defines an electronic security perimeter as "the logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol." NERC Glossary at 39.

[12] *See* Alert at Mitigation Section; *see also* Department of Homeland Security, *Seven Steps to Effectively Defend Industrial Control Systems* at 3.

11. The Commission seeks comment on whether the CIP Reliability Standards should be modified to require isolation between the Internet and BES Cyber Systems in Control Centers performing the functions of a transmission operator. In addition, the Commission seeks comment on the operational impact to the Bulk-Power System if BES Cyber Systems were isolated from the Internet in all Control Centers performing transmission operator functions. Specifically, the Commission seeks comment on what, if any, reliability issues might arise from such a requirement. For example, would requiring isolation prevent an activity required by another Reliability Standard? If isolation is required, is logical isolation preferable to physical isolation (or vice versa) and, if so, why? The Commission also seeks comment on whether and how such a requirement might affect a transmission operator's communications with its reliability coordinator or other applicable entities required under the Reliability Standard. Finally, if isolation is not required, are there communications with these Control Centers for which the use of one-way data diodes would be reliable and appropriate?

B. Application Whitelisting for BES Cyber Systems in Control Centers

12. Application whitelisting is a computer administration practice used to prevent unauthorized programs from running.[13] The purpose is primarily to protect computers and networks from harmful applications, and, to a lesser extent, to prevent unnecessary demand for computer resources. The "whitelist" is a list of applications granted

[13] *See* Alert at Mitigation Section.

permission to run by the user or an administrator. Whitelisting works best when applied to static cyber systems.[14]

13. In response to the Ukraine incident, the Alert recommended that:

> asset owners take defensive measures by leveraging best practices to minimize the risk from similar malicious cyber activity. Application Whitelisting (AWL) can detect and prevent attempted execution of malware uploaded by malicious actors. The static nature of some systems, such as database servers and HMI computers, make these ideal candidates to run AWL. Operators are encouraged to work with their vendors to baseline and calibrate AWL deployments.

Similarly, a December 2015 document by DHS identifies application whitelisting as the first of seven strategies to defend industrial control systems and states that this strategy would have "potentially mitigated" 38 percent of ICS-CERT Fiscal Year 2014 and 2015 incidents, more than any of the other strategies.[15] While the NERC Guidelines and Technical Basis document associated with Reliability Standard CIP-007-6, Requirement R3 identifies application whitelisting as an option for mitigating malicious cyber activity, its use is not mandatory.[16] The Guidelines and Technical Basis discussion in Reliability Standard CIP-007-6 explains:

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[14] *Id.*

[15] Seven Steps to Effectively Defend Industrial Control Systems at 1.

[16] Reliability Standard CIP-007-6, Requirement R3 provides that "[e]ach Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in CIP-007-6 Table R3 – Malicious Code Prevention" and lists application whitelisting as an option. In addition, the CIP Reliability Standards require a combination of ensuring that an individual's privileges are the minimum necessary to perform their work function (i.e., "least privilege") and anti-

(continued…)

> Due to the wide range of equipment comprising the BES Cyber Systems and the wide variety of vulnerability and capability of that equipment to malware as well as the constantly evolving threat and resultant tools and controls, it is not practical within the standard to prescribe how malware is to be addressed on each Cyber Asset. Rather, the Responsible Entity determines on a BES Cyber System basis, which Cyber Assets have susceptibility to malware intrusions and documents their plans and processes for addressing those risks and provides evidence that they follow those plans and processes. There are numerous options available including traditional antivirus solutions for common operating systems, white-listing solutions, network isolation techniques, Intrusion Detection/Prevention (IDS/IPS) solutions, etc.[17]

14. While application whitelisting is identified above as one available option, the Ukraine incident and the subsequent Alert raise the question of whether application whitelisting should be required. Application whitelisting could be a more effective mitigation tool than other mitigation measures because whitelisting allows only software applications and processes that are reviewed and tested before use in the system network. By knowing all installed applications, the security professional can set the application whitelisting program to know the application is approved; all unapproved applications will trigger an alert.

15. The Commission seeks comment on whether the CIP Reliability Standards should be modified to require application whitelisting for all BES Cyber Systems in Control Centers. Is application whitelisting appropriate for all such systems? If not, are there

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malware (i.e., "blacklisting"). *See, e.g.*, Reliability Standard CIP-004-6, Requirement R4 and Guidelines and Technical Basis; Reliability Standard CIP-007-6, Requirement R3.

[17] Reliability Standard CIP-007-6, Guidelines and Technical Basis, at 4.

certain devices or components on such systems for which it is appropriate? In addition, the Commission seeks comment on the operational impact, including potential reliability concerns, for each approach.

III. Comment Procedures

16. The Commission invites interested persons to submit comments, and other information on the matters, issues and specific questions identified in this notice. Comments are due **[INSERT DATE that is 60 days from publication in the FEDERAL REGISTER]**. Comments must refer to Docket No. RM16-18-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

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

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

19. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section

below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

IV. Document Availability

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

21. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

22. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676)

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

By direction of the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

156 FERC ¶ 61,052
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Revised Critical Infrastructure Protection Reliability Standards — Docket No. RM15-14-001

ORDER NO. 822-A

ORDER DENYING REHEARING

(Issued July 21, 2016)

1. In Order No. 822, the Commission approved seven modified critical infrastructure protection (CIP) Reliability Standards submitted by the North American Electric Reliability Corporation (NERC).[1] In addition, pursuant to section 215(d)(5) of the Federal Power Act (FPA), the Commission directed NERC to develop additional modifications to the Critical Infrastructure Protection (CIP) Reliability Standards.[2] Foundation for Resilient Societies (Resilient Societies) and Isologic filed requests for

[1] *Revised Critical Infrastructure Protection Reliability Standards*, Order No. 822, 81 Fed. Reg. 4177 (January 26, 2016), 154 FERC ¶ 61,037 (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).

[2] 16 U.S.C. § 824o(d)(5) (2012).

rehearing of Order No. 822.[3] For the reasons discussed in the body of this order, we deny rehearing.[4]

I. Background

2. In Order No. 791, the Commission approved the CIP version 5 Standards.[5] In addition, pursuant to section 215(d)(5) of the FPA, the Commission directed NERC, *inter alia*, to develop a definition for the term "communication networks" for inclusion in the NERC Glossary of Terms and to develop new or modified Reliability Standards to address the protection of nonprogrammable components of communications networks.[6] Order No. 791 concluded that, without the modifications directed by the Commission, a reliability gap might exist because the CIP version 5 Standards "do not address security controls needed to protect the nonprogrammable components of communications networks."[7] On February 13, 2015, NERC submitted a petition seeking approval of the revised CIP Reliability Standards that NERC developed in response to the directives in Order No. 791.

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[3] The rehearing requests submitted by Resilient Societies and Isologic raise similar issues and cite to each other for support. *See, e.g.*, Resilient Societies Request at 13; Isologic Request at 2.

[4] On March 29, 2016, Resilient Societies, Isologic and Applied Control Solutions, LLC filed a joint motion to "reopen the evidentiary record in Docket No. RM15-14-000." However styled, the joint motion is a supplemental request for rehearing of Order No. 822. As the joint motion was filed beyond the 30 days allowed by statute, 16 U.S.C. § 825l(a) (2012), the Federal Power Act does not allow us to consider the supplement here. *See also* 18 C.F.R. § 385.713(b) (2014); *Public Service Company of New Hampshire*, 134 FERC ¶ 61,041, at P 7 n.13 (2011). We note, however, that certain issues raised in the joint motion may be considered through other procedures discussed below.

[5] *Version 5 Critical Infrastructure Protection Reliability Standards*, Order No. 791, 78 Fed. Reg. 72,755 (Dec. 3, 2013), 145 FERC ¶ 61,160 (2013), *order on clarification and reh'g*, Order No. 791-A, 146 FERC ¶ 61,188 (2014) (approving Reliability Standards CIP-002-5, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1 and CIP-011-1 (CIP version 5 Standards)).

[6] Order No. 791, 145 FERC ¶ 61,160 at P 150.

[7] *Id.* P 149.

II. Discussion

A. Communication Networks and Substations

Order No. 822

3. Order No. 822 approved NERC's proposed alternative to the directive in Order No. 791 that NERC develop a definition of "communication networks." The approved alternative required responsible entities to develop controls to secure nonprogrammable components of communication networks at Control Centers with High or Medium Impact BES Cyber Systems.[8] The Commission determined that NERC's alternative addressed, in part, the concerns in Order No. 791 regarding the security of nonprogrammable components of communication networks. However, the Commission determined that further "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."[9] Accordingly, in addition to approving the CIP Reliability Standards, the Commission directed NERC, pursuant to section 215(d)(5) of the FPA, to modify Reliability Standard CIP-006-6 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).[10]

4. In addition, Order No. 822 directed NERC to conduct a study to assess the effectiveness of the CIP version 5 Standards regarding remote access controls, the risks posed by remote-access related threats and vulnerabilities, and appropriate mitigating controls for any identified risks. The Commission directed NERC to consult with Commission staff on the general content of the remote access report, which is due within one year of the implementation of the CIP version 5 Standards for High and Medium Impact BES Cyber Systems.[11]

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[8] Order No. 822, 154 FERC ¶ 61,037 at P 52.

[9] *Id.* P 53.

[10] *Id.*

[11] *Id.* P 64.

Request

5. Resilient Societies and Isologic contend that the Commission erred in approving NERC's alternative approach to the Order No. 791 directive to create a NERC Glossary of Terms definition for "communication networks." Resilient Societies and Isologic maintain that the Commission's decision to approve NERC's alternative approach and not to require an "inclusive" definition of communication networks, which includes substations, violates the intent of FPA section 215.[12] Resilient Societies cites the definition of "reliable operation" and "cybersecurity incident" in FPA section 215 to assert that the "unambiguous Congressional intent to protect 'communication networks' from 'cybersecurity incidents' … is indicated by the careful definition of 'cybersecurity incident' in Section 215."[13] Resilient Societies also contends that the Commission, by approving NERC's alternative approach, unlawfully delayed consideration of protecting a broader definition of communication networks.

6. Resilient Societies maintains that Order No. 822 erred by excluding electric grid substations from mandatory cyber protections in the CIP Reliability Standards.[14] In addition, Resilient Societies raises a concern that Order No. 822 does not reflect lessons learned from a December 23, 2015 cyber attack on Ukraine's electric grid. In particular, Resilient Societies notes that the targets of the attack in the Ukraine incident were, in relevant part, electric grid substations and associated control centers.[15]

Commission Determination

7. We deny rehearing of the determinations contained in Order No. 822 pertaining to the protection of communication networks in the CIP Reliability Standards.

8. There is no support for Resilient Societies' assertion that FPA section 215 requires development of a definition of communication networks for inclusion in the NERC Glossary of Terms. While the definition of "cybersecurity incident" in FPA section 215(a)(7) contains the term "communication networks," section 215 nowhere directs the Electric Reliability Organization (ERO) or the Commission to define that

[12] *See* Resilient Societies Request at 3-6; Isologic Request at 17-18.

[13] Resilient Societies Request at 5.

[14] *Id.* at 6-9.

[15] *Id.* at 8.

term. The Commission also rejects the contention that the definition of "reliable operation" in FPA section 215(a)(4) mandates the broader definition of "communication networks" advocated by Resilient Societies, which includes substations.

9. FPA section 215(d)(2) states that the Commission "may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest." In Order No. 822, the Commission determined that the CIP Reliability Standards, by protecting control centers with High and Medium Impact BES Cyber Systems, met that standard and satisfied in part the reliability gap discussed in Order No. 791. The Commission concluded, however, that modifications to the CIP Reliability Standards "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."[16] Order No. 822 also directed NERC to develop modifications to Reliability Standard CIP-006-6 to protect control centers with Low Impact assets. These determinations, taken together, address Resilient Societies' assertions of error regarding the need to define the term communication networks and, instead, reflect ongoing efforts by the ERO and Commission to develop and approve CIP Reliability Standards that satisfy the standard set forth in FPA section 215(d)(2) for approving Reliability Standards and address evolving cybersecurity threats to the Bulk-Power System.[17]

10. We also reject the claim that substations are excluded from protection under the CIP Reliability Standards. All bulk electric system substations within the Commission's jurisdiction under FPA section 215 are protected under the CIP Reliability Standards. All BES Cyber Assets contained in those substations are classified as High, Medium or Low Impact under the CIP Reliability Standards and, thus, are subject to the corresponding controls imposed by the CIP Reliability Standards.[18] Further, Resilient Societies appears to advocate for the protection of distribution level substations that are not included in the bulk power system. Section 215 of the FPA, however, authorizes the ERO to develop

[16] Order No. 822, 154 FERC ¶ 61,037 at P 53.

[17] Order No. 822 explained the Commission's reasons for accepting NERC's alternative proposal to the Order No. 791 directive to create a NERC Glossary of Terms definition for "communication networks." *See* Order No. 822, 154 FERC ¶ 61,037 at PP 52-55.

[18] *See* Order No. 791, 145 FERC ¶ 61,160 at P 41 (citing Reliability Standard CIP-002-5).

and the Commission to approve Reliability Standards that "provide for the protection of the bulk power system," and does not apply to local distribution facilities.[19] Thus, we deny this aspect of the request for rehearing as outside the scope of the Commission's authority.

11. With respect to Resilient Societies' concern that Order No. 822 did not incorporate lessons learned from the Ukraine incident, any relevant lessons from the Ukraine incident could be considered in future versions of the CIP Reliability Standards.[20] As discussed above, Order No. 822 directed NERC to conduct a study to assess the effectiveness of the CIP version 5 Standards remote access controls, the risks posed by remote-access related threats and vulnerabilities, and appropriate mitigating controls for any identified risks. We expect the remote access study to address remote communications associated with Control Centers and substations. In addition, we expect NERC to incorporate analyses of the Ukraine incident conducted by the Department of Homeland Security, NERC and others in the remote access study, and we direct Commission staff, as part of the consultative process between NERC staff and Commission staff directed in Order No. 822, to work with NERC staff to evaluate the Ukraine incident in the remote access study.[21] In addition to the remote access study, the Commission is also concurrently issuing a Notice of Inquiry concerning: (1) isolation between the internet and cyber systems in control centers performing transmission operator functions; and (2) mandatory application "whitelisting" for all cyber systems in control centers.[22]

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[19] *See* 16 U.S.C. § 824o(a)(3).

[20] The Commission issued Order No. 822 less than one month after the Ukraine incident and more than one month prior to the release of a Department of Homeland Security Industrial Control Systems Cyber Emergency Response Team alert on the Ukraine incident. *See* ICS-CERT Alert IR-ALERT-H-16-056-01, https://ics-cert.us-cert.gov/alerts/IR-ALERT-H-16-056-01.

[21] Order No. 822, 154 FERC ¶ 61,037 at P 64 ("NERC should consult with Commission staff to determine the general contents of the directed report.").

[22] *See Cyber Systems in Control Centers*, Notice of Inquiry, Docket No. RM16-18-000 (2016).

B. Removal of Malware under CIP Reliability Standards

Request

12. Resilient Societies contends that Order No. 822 erred by not requiring the removal of cyber malware embedded in the Bulk-Power System. Resilient Societies requests that the Commission modify Order No. 822 "to include the duty to assess, to monitor, and to remove cyber malware from the system components of NERC-registered entities subject to FERC jurisdiction."[23]

Commission Determination

13. We deny Resilient Societies' rehearing request regarding the removal of malware under the CIP Reliability Standards. The CIP Reliability Standards already address the threat posed by malicious code to the Bulk-Power System. Specifically, Reliability Standard CIP-007-6, Requirement R3 requires responsible entities to "[d]eploy method(s) to deter, detect, or prevent malicious code" (Requirement R3.1) and to "mitigate the threat of detected malicious code" (Requirement R3.2). In the Guidelines and Technical Basis section of Reliability Standard CIP-007-6, the subsection devoted to Requirement R3.2 makes clear that "[w]hen malicious code is detected on a Cyber Asset within the applicability of this requirement, the threat posed by that code must be mitigated."

C. Other Request

Request

14. Resilient Societies requests that "the Commission modify its Order No. 822 to clarify that it is not the intent of the Commission to preclude complementary operational cybersecurity programs; and that the requirements of [Commission] Order No. 822 are not intended as a barrier to essential cybersecurity protections otherwise duly authorized."[24]

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[23] Resilient Societies Request at 10.

[24] *Id.* at 12.

Commission Determination

15. In Order No. 822, the Commission approved the CIP Reliability Standards pursuant to FPA section 215(d)(2). Nothing in Order No. 822 or the CIP Reliability Standards purports to preclude additional measures designed to address cybersecurity threats.[25]

The Commission orders:

The Commission hereby denies rehearing, for the reasons discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

[25] *See, e.g.*, 16 U.S.C. § 824o(i)(3) (2012) ("nothing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard").

156 FERC ¶ 61,017
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Availability of Certain North American Electric Reliability Corporation Databases to the Commission — Docket No. RM15-25-000

ORDER NO. 828

ORDER CLARIFYING EFFECTIVE DATE AND COMPLIANCE DATE

July 7, 2016

1. In Order No. 824, the Commission issued a final rule amending its regulations, pursuant to section 215 of the Federal Power Act (FPA),[1] to require the North American Electric Reliability Corporation (NERC) to provide the Commission, and Commission staff, with access, on a non-public and ongoing basis, to certain databases compiled and maintained by NERC.[2] The Commission directed that "[t]his rule will become effective upon issuance of the final rule in Docket No. RM16-15-000."[3]

2. To conform with Federal Register guidelines, the Commission clarifies the final rule's effective date and compliance date as follows:

> *Effective date:* This rule will become effective [**INSERT DATE of publication in the FEDERAL REGISTER**].

[1] 16 U.S.C. § 824o (2012).

[2] *Availability of Certain North American Electric Reliability Corporation Databases to the Commission*, Order No. 824, 155 FERC ¶ 61,275 (June 16, 2016).

[3] *Id.* P 75.

Compliance date: The compliance date is based on issuance of the final rule in Docket No. RM16-15-000. The Commission will publish a document in the Federal Register announcing the compliance date.

This clarification conforms the Database Final Rule to the Commission's stated intent of deferring Commission access to the databases "until the Commission issues a final rule adopting regulations to implement its recently-expanded authority to protect against the disclosure of 'critical electric infrastructure information.'"[4]

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

[4] *Id.* P 46.

156 FERC ¶ 61,062
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM16-8-000; Order No. 828]

Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities

(Issued July 21, 2016)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is modifying the *pro forma* Small Generator Interconnection Agreement (SGIA). The *pro forma* SGIA establishes the terms and conditions under which public utilities must provide interconnection service to small generating facilities of no larger than 20 megawatts. The Commission is modifying the *pro forma* SGIA to require newly interconnecting small generating facilities to ride through abnormal frequency and voltage events and not disconnect during such events. The specific ride through settings must be consistent with Good Utility Practice and any standards and guidelines applied by the transmission provider to other generating facilities on a comparable basis. The Commission already requires generators interconnecting under the Large Generator Interconnection Agreement to meet such requirements, and it would be unduly discriminatory not to also impose these requirements on small generating facilities. The Commission concludes

that newly interconnecting small generating facilities should have ride through requirements comparable to large generating facilities.

EFFECTIVE DATE: This Final Rule will become effective **[Insert Date 65 days after publication in the FEDERAL REGISTER]**.

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SUPPLEMENTARY INFORMATION:

156 FERC ¶ 61,062
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities	Docket No. RM16-8-000

ORDER NO. 828

FINAL RULE

(Issued July 21, 2016)

1. In this Final Rule, the Commission modifies the *pro forma* Small Generator Interconnection Agreement (SGIA) originally set forth in Order No. 2006[1] and revised in Order No. 792[2] to require small generating facilities interconnecting through the SGIA to ride through abnormal frequency and voltage events and not disconnect during such events.[3] Pursuant to section 206 of the Federal Power Act (FPA), the Commission finds

[1] *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180, *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006) (Order No. 2006).

[2] *Small Generator Interconnection Agreements and Procedures*, Order No. 792, 145 FERC ¶ 61,159 (2013), *clarified*, Order No. 792-A, 146 FERC ¶ 61,214 (2014) (Order No. 792).

[3] In Order No. 2003, the Commission defined "ride through" to mean a generating facility staying connected to and synchronized with the transmission system during

(continued ...)

that, given the changes to conditions since the Commission last evaluated whether to impose ride through requirements on small generating facilities, the revisions to the *pro forma* SGIA are necessary to remedy undue discrimination by ensuring that small generating facilities have ride through requirements comparable to large generating facilities.[4]

2. As a result of this Final Rule, small generating facilities are required to not disconnect automatically or instantaneously from the system or equipment of the transmission provider and any affected systems for an under-frequency or over-frequency condition, or an under-voltage or over-voltage condition. Furthermore, the transmission provider must coordinate the small generating facility's protective equipment settings with any automatic load shedding program (e.g., under-frequency load shedding, under-voltage load shedding). The specific ride through settings must be consistent with Good Utility Practice and any standards and guidelines applied by the transmission provider to other generating facilities on a comparable basis. These requirements will apply to new interconnection customers that execute or request the unexecuted filing of an SGIA on or

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system disturbances within a range of over- and under-frequency conditions, in accordance with Good Utility Practice. *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 562 n.88 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008) (Order No. 2003). Reliability Standard PRC-024-1 requires bulk electric system generation to ride through over- and under- voltage conditions.

[4] 16 U.S.C. 824e.

after the effective date of this Final Rule. These requirements will also apply to existing interconnection customers that, pursuant to a new interconnection request, execute or request the unexecuted filing of a new or modified SGIA on or after the effective date of this Final Rule.

I. Background

3. The *pro forma* SGIA establishes the terms and conditions under which public utilities must provide interconnection service to small generating facilities of no larger than 20 megawatts (MW). Currently, the *pro forma* SGIA does not mandate that small generating facilities have the capability to ride through voltage or frequency disturbances.

4. In Order No. 2006, the Commission explored whether voltage ride through requirements proposed for large wind generating facilities should apply to small generating facilities.[5] A commenter during that proceeding asked the Commission to implement ride through standards for small generating facilities similar to those proposed for large generating facilities. However, other commenters responded that special capabilities, such as low voltage ride through, were not needed for any small generating facility, whether wind-powered or not. The Commission concluded that wind generating facilities interconnecting under Order No. 2006 would be small and would have minimal

[5] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 24.

impact on the transmission provider's electric system and, therefore, need not be subject to ride through requirements.[6]

5. More recently, the Commission again addressed these requirements with regard to small generating facilities in Order No. 792.[7] In that proceeding, the Commission proposed to revise section 1.5.4 of the *pro forma* SGIA to address the reliability concern related to automatic disconnection of small generating facilities during over- and under-frequency events, which could become a greater concern at high penetrations of distributed energy resources.[8] The proposed revisions to section 1.5.4 would have required the interconnection customer to design, install, maintain, and operate its small generating facility, in accordance with the latest version of the applicable standards to prevent automatic disconnection during over- and under-frequency events.[9]

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[6] *Id.* The penetration of small generating facilities has increased since the Commission analyzed the impact of small generating facilities in Order No. 2006. *See infra* P 8.

[7] Order No. 792, 145 FERC ¶ 61,159.

[8] *Small Generator Interconnection Agreements and Procedures*, Notice of Proposed Rulemaking, 142 FERC ¶ 61,049, at P 46 (2013) (Order No. 792 NOPR). NERC defines distributed energy resources to mean resources that are distributed geographically and not centralized like traditional generation resources. NERC, *Essential Reliability Services Task Force Measures Report*, (Nov. 2015), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.

[9] *Id.*

6. The Commission declined to adopt this proposed revision in Order No. 792.[10] Instead, the Commission recognized that the Institute of Electrical and Electronics Engineers (IEEE) was, at the time, in the process of amending IEEE Standard 1547, which is an interconnection standard for interconnecting distributed resources with electric power systems that is referenced in the Small Generator Interconnection Procedures.[11] The Commission also noted that IEEE was about to begin a full IEEE Standard 1547 revision process in 2014, where frequency and voltage ride through requirements in the standard were to be evaluated. The Commission concluded that it would continue to monitor the IEEE Standard 1547 revision process and could revise the *pro forma* SGIA as it relates to IEEE Standard 1547 in the future, if necessary.[12]

7. Since the Commission issued Order No. 792, IEEE has completed a partial revision of IEEE Standard 1547, which is IEEE Standard 1547a. IEEE is now in the process of fully revising IEEE Standard 1547. The partially revised standard, IEEE Standard 1547a, permits generating facilities to have wider trip settings compared with IEEE Standard 1547. These wider trip settings allow generating facilities to stay connected to the grid for greater frequency or voltage excursions facilitating their ability

[10] Order No. 792, 145 FERC ¶ 61,159 at P 220.

[11] *Id.*

[12] *Id.*

to ride through such excursions. IEEE Standard 1547a also permits – but does not mandate – ride through requirements.[13]

8. Following the Commission's evaluation of the need for ride through requirements for small generating facilities in the Order Nos. 2006 and 792 rulemaking proceedings, the impact of small generating facilities on the grid has changed, and the amount has increased. For example, as the North American Electric Reliability Corporation (NERC) has noted in multiple reports, the mix of generation resources is changing and the high penetration of distributed energy resources will impact the reliability of the electric grid if sufficient care is not taken to mitigate potential adverse impacts.[14] NERC also has found that a lack of coordination between small generating facilities and Reliability Standards can lead to events where system load imbalance may increase during frequency excursions or voltage deviations due to the disconnection of distributed energy resources, which may exacerbate a disturbance on the Bulk-Power System.[15] In addition, the

[13] IEEE Standard 1547a contains "must trip" requirements; it does not have "must ride through" requirements. By widening the trip settings, IEEE Standard 1547a permits generating facilities to trip at a later time. This change effectively allows generating facilities to ride through disturbances, but they are not required to do so.

[14] *See* NERC Special Report, *Potential Bulk System Reliability Impacts of Distributed Resources* (Aug. 2011), http://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf; *see also* NERC Integration of Variable Generation Task Force Draft Report, *Performance of Distributed Energy Resources During and After System Disturbance* (Dec. 2013), http://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20I1/IVGTF17_PC_FinalDraft_December_clean.pdf.

[15] NERC Essential Reliability Services Report at 21.

Commission has observed the growth in grid-connected solar photovoltaic generation since the issuance of Order No. 2006 and the growth in small generator interconnection requests driven by state renewable portfolio standards, reductions in cost for solar panels, and deployment of new technologies.[16] Moreover, technology now available to newly interconnecting small generating facilities, such as smart inverters, permits the capability to ride through frequency and voltage disturbances.[17]

II. Notice of Proposed Rulemaking

9. On March 23, 2016, the Commission issued a Notice of Proposed Rulemaking that proposed to add new section 1.5.7 to the *pro forma* SGIA,[18] which would require small generating facilities to ride through defined frequency and voltage disturbances.

10. In response to the NOPR, eleven entities submitted substantive comments, which generally support the Commission's proposal.[19] These comments have informed our determinations in this Final Rule.

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[16] *See, e.g.*, Order No. 792, 145 FERC ¶ 61,159 at P 15; Solar Energy Indus. Ass'n, Solar Industry Data, http://www.seia.org/research-resources/solar-industry-data (last visited Jul. 5, 2016).

[17] *See* Electric Power Research Institute, *Recommended Settings for Voltage and Frequency Ride Through of Distributed Energy Resources*, 28-29 (May 2015), http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002006203.

[18] *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, 154 FERC ¶ 61,222 (2016) (NOPR).

[19] Appendix A lists the entities that submitted comments and the shortened names used throughout this Final Rule to describe those entities.

III. Discussion

11. For the reasons discussed below, we adopt the NOPR proposal and require small generating facilities to ride through abnormal frequency and voltage events comparable to large generating facilities. We find that, given the changes to conditions since the Commission last evaluated whether to impose ride through requirements on small generating facilities, the revisions to the *pro forma* SGIA are necessary to remedy undue discrimination by ensuring that small generating facilities have ride through requirements comparable to large generating facilities.[20] Specifically, since the Commission's last consideration of this issue, IEEE has revised its standards, and IEEE Standard 1547a now provides wider trip settings that allow small generating facilities more leeway to ride through disturbances. In addition, distributed energy resources have had an increasing presence and impact on the electric system. The absence of ride through requirements for small generating facilities increases the risk that an initial voltage or frequency disturbance may cause a significant number of small generating facilities to trip across a particular area or Interconnection, further exacerbating the initial disturbance. Large generating facilities are already subject to ride through requirements to avoid these types of occurrences.[21]

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[20] 16 U.S.C. 824e. The Commission routinely evaluates the effectiveness of its regulations and policies in light of changing industry conditions to determine if changes in these conditions and policies are necessary. *See, e.g.*, *Integration of Variable Energy Resources*, Order No. 764, FERC Stats. & Regs, ¶ 31,331 (2012).

[21] *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 562 n.88.

12. The Commission acknowledges that some areas have a greater penetration of distributed resources than others at this time. Nevertheless, the Commission believes that the proposed reforms to the *pro forma* SGIA are appropriate on an industry-wide basis now. The Commission continues to affirm that this Final Rule is not intended to interfere with state interconnection procedures or agreements in any way. The *pro forma* SGIA applies only to interconnections made subject to a jurisdictional open access transmission tariff (OATT) for the purposes of jurisdictional wholesale sales. Similar to the approach in Order Nos. 2006 and 792, the Commission hopes that the changes to the *pro forma* SGIA resulting from this Final Rule will be helpful to states when updating their own interconnection rules, but the states are under no obligation to adopt the provisions of the Commission's proposal.[22]

A. Revision of the *Pro Forma* SGIA

1. NOPR Proposal

13. In the NOPR, the Commission proposed to revise the *pro forma* SGIA to include proposed section 1.5.7, which would require interconnection customers to ensure the frequency ride through capability and the voltage ride through capability of small generating facilities that execute or request the unexecuted filing of interconnection agreements following the effective date of the proposed section 1.5.7. Proposed section 1.5.7 would also require a small generating facility not to disconnect automatically or

[22] Order No. 792, 145 FERC ¶ 61,159 at P 27; Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 8.

instantaneously from the system or equipment of the transmission provider and any affected systems for an under-frequency or over-frequency condition, or an under-voltage or over-voltage condition. In addition, the transmission provider must coordinate the small generating facility's protective equipment settings with any automatic load shedding program.

2. Comments

14. The substantive comments filed in response to the NOPR generally support the proposal to modify the *pro forma* SGIA.[23] Commenters agree with the need for fair and equitable treatment between small and large generating facilities, the need for effective protections for system operation while also avoiding increased costs, and the potential to improve system stability and reliability over the coming years by adopting the proposed modifications to the *pro forma* SGIA.[24] Commenters acknowledge the proposal's benefits, stating it will simplify operational conditions, especially considering the rising small generator penetration levels on the distribution system.[25] NERC states that revising the *pro forma* SGIA to impose ride through requirements would be consistent

[23] Peak Reliability Comments at 3; Idaho Power Comments at 2; PNM Comments at 1; SoCal Edison Comments at 2; ISO/RTO Council Comments at 6; Trade Associations Comments at 4; Bonneville Comments at 1; EPRI Comments at 7; NERC Comments at 2; PG&E Comments at 2.

[24] SoCal Edison Comments at 2; Peak Reliability Comments at 3; EPRI Comments at 7.

[25] PNM Comments at 2; Trade Associations Comments at 7.

with the results of a number of NERC's reliability assessments.[26] Trade Associations and PNM agree that the absence of ride through requirements for small generating facilities increases the risk that an initial voltage or frequency disturbance may cause a significant number of small generating facilities to trip offline, exacerbating the initial disturbance.[27]

15. Idaho Power claims that if more small generation facilities connect to its system, without the proposed changes to the *pro* forma SGIA, it would become increasingly difficult for it to comply with Reliability Standards PRC-006-2 (Automatic Underfrequency Load Shedding) and BAL-003-1.1 (Frequency Response and Frequency Bias Setting).[28]

16. The ISO/RTO Council recommends that the proposed required characteristics for small generating facilities should be demonstrated "as tested," and that this should be specified in the *pro forma* SGIA section 1.5.7. The ISO/RTO Council notes that demonstrating characteristics "as tested" is already required under section 24 of the large generator interconnection agreement (LGIA). The ISO/RTO Council further explains that, while the *pro forma* SGIA does not presently have such language, the "as tested"

[26] NERC Comments at 4.

[27] PNM Comments at 2; Trade Associations Comments at 7.

[28] Idaho Power Comments at 2.

requirement applies to small generating facilities pursuant to the directives in Order No. 2006.[29]

17. Some commenters request that the Commission delay implementation of the Final Rule. While EPRI does not believe that additional action is required for other existing interconnected small generating facilities, EPRI comments that additional reliability studies may be required if aggregate penetration levels increase sufficiently before the modifications to the *pro forma* SGIA and revised IEEE Standard 1547 become effective.[30] EPRI notes the need for timely revision and balloting of IEEE Standard 1547, as well as prompt adoption of the standard.[31] Trade Associations suggest waiting until after key industry standards are approved and the safety and effectiveness of smart inverter technology is validated. [32] Trade Associations request time to allow entities to resolve outstanding concerns such as personnel and asset safety, as well as the ability to effectively coordinate protections systems between the local utility and interconnecting resources.[33] EPRI and IEEE assert that relevant stakeholders, including transmission owners and transmission operators, should engage with the IEEE Standard 1547 revision

[29] ISO/RTO Council Comments at 7 (citing Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 59).

[30] EPRI Comments at 7.

[31] *Id.* at 7-8.

[32] Trade Associations Comments at 7-8; EPRI Comments at 7-8.

[33] Trade Associations Comments at 7-8.

process to ensure that the final framework and requirements for ride through can be consistently applied to meet individual system needs.[34]

18. Trade Associations claim that the new ride through capability requirements are only possible through smart inverter technology, but point out that key associated specifications contained in the reference standards remain unapproved. Trade Associations explain that distribution feeders are often designed as radial feeders that depend on remote generation to quickly disconnect when the utility source is disconnected. According to Trade Associations, failure to do so may result in unintentional islands which create safety hazards for personnel and customers, as well as liability concerns. Trade Associations caution that directing small generation facilities to ride through disturbances may create islanding conditions and relaxed response to fault conditions.

19. Further, Trade Associations claim that more industry discussion is needed to ensure that small generators' interconnections meet the unique regional utility safety and reliability concerns before the proposed revisions to section 1.5.7 of the *pro forma* SGIA are adopted. Trade Associations suggest that the Commission include the issues in this proceeding in the three regional technical conferences recommended by Edison Electric Institute in Docket No. RM16-6-000.[35]

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[34] EPRI Comments at 7-8.

[35] Trade Associations Comments at 13-14. In Docket No. RM16-6-000, the Commission issued a Notice of Inquiry seeking comment on the need for reforms to its

(continued ...)

20. Trade Associations also suggest that the Commission explore how changes made to the *pro forma* SGIA often influence state regulations. Trade Associations note that distribution level interconnections are broadly supported by industry standards and company interconnection rules; and alignment to *pro forma* SGIA may be inappropriate for some state regulations.[36]

3. Commission Determination

21. As discussed above, we find the revisions to the *pro forma* SGIA adopted herein are necessary to remedy treatment that is unjust, unreasonable, and unduly discriminatory and preferential because there is no technical or economic basis to require small and large generating facilities to follow different requirements in regards to voltage and frequency ride through. Our revisions will place similar requirements on large generating facilities and small generating facilities for ride through capabilities. As discussed above, the NOPR proposal received widespread support from commenters. Further, the absence of ride through requirements for small generating facilities may have adverse impacts on the reliability of the electric grid. We find that the lack of ride through requirements for small generating facilities is unduly discriminatory. This is due to the increased presence and impact of small generating facilities, including distributed energy resources, on the electric system, that could create reliability issues if

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rules and regulations regarding the provision and compensation of primary frequency response.

[36] Trade Associations Comments at 14.

they do not have the capability to ride through voltage or frequency disturbances. Further, improvements in technology, such as smart inverters, make it economically feasible for small generating facilities to ride through voltage and frequency disturbances. We acknowledge that some areas have a greater penetration of distributed resources than others at this time. Nevertheless, we believe that the proposed reforms to the *pro forma* SGIA are appropriate on an industry-wide basis now and that deferred action would not be appropriate.

22. We recognize the work of the IEEE 1547 Working Group, but we determine that there is a pressing need to establish ride through capability requirements at this time because we expect a continuing increase in penetration of small generating facilities. The revisions to the *pro forma* SGIA that we now approve will require the small generating facility to implement ride through settings based on a technical standard established by the transmission provider.

23. While Trade Associations point out that IEEE is revising IEEE Standard 1547, the standard does not currently require ride through capability. We are acting now to ensure that all affected jurisdictional small generating facilities will have the ride through capability, as allowed by IEEE Standard 1547a.[37]

24. We are persuaded by the ISO/RTO Council's recommendation to add the "as tested" language to section 1.5.7 of the *pro forma* SGIA to harmonize the requirements

[37] As we also explained in the NOPR, the Commission's proposal was not intended to impede the ongoing efforts of the IEEE 1547 Working Group, and we reiterate that point here. NOPR, 154 FERC ¶ 61,222 at P 8 n.19.

between the *pro forma* SGIA and th*e pro forma* LGIA. Pursuant to this "as tested" language, the interconnection customer must provide the successfully completed test results to the transmission provider in a similar manner as in section 24.4 of the *pro forma* LGIA. We believe that the addition of "as tested" language does not create an extra burden on either party to an interconnection agreement because the *pro forma* SGIA already includes testing requirements in section 2.1.[38] The "as tested" language assures the transmission provider that the required ride through capability can actually be performed by the small generating facility.

25. We hereby adopt new section 1.5.7 of the *pro forma* SGIA showing the changes made to the Commission's proposal in the NOPR as follows:

> 1.5.7 The Interconnection Customer shall ensure "frequency ride through" capability and "voltage ride through" capability of its Small Generating Facility. The Interconnection Customer shall enable these capabilities such that its Small Generating Facility shall not disconnect automatically or instantaneously from the system or equipment of the Transmission Provider and any Affected Systems for a defined under-frequency or over-frequency condition, or an under-voltage or over-voltage condition, as tested pursuant to section 2.1 of this agreement. The defined conditions shall be in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. . . .

[38] *Pro forma* SGIA, Section 2.1 "Equipment Test and Inspection."

26. We recognize the Trade Associations' concern about potential tension between ride through requirements and anti-islanding protection. Ensuring the safety of utility lineworkers is critically important, and an issue the Commission takes seriously. Based on our consideration of the record, we believe that the ride through requirements adopted herein are technically and safely achievable. In particular, we note that this Final Rule provides significant flexibility for transmission providers to account for potential safety and islanding concerns. For example, the transmission provider can determine specific ride through settings needed to address those concerns so long as those settings are consistent with Good Utility Practice and any standards and guidelines applied to other generating facilities on a comparable basis.

27. Furthermore, we note that islanding and personnel safety are not new issues resulting from this Final Rule; to the contrary, they will continue to be important concerns regardless of the reforms adopted in this Final Rule. Accordingly, we emphasize the importance of implementing ride through requirements through careful coordination between the interconnection customer and the transmission provider, as well as the utilization of appropriate safety procedures for utility personnel, particularly effective and thorough communication for lineworkers in the field, when performing remedial actions following a system disturbance. We support the continued efforts by industry to explore innovative ways to detect island conditions in order to mitigate the risk of unintentional islands.

28. In light of our goal to prevent undue discrimination, we seek to provide guidelines that will be applied to generating facilities on a comparable basis, while allowing for

justified differences on a case by case basis. For example, if a transmission provider believes a particular facility has a higher risk of unintentional islanding due to specific conditions on that facility, the revisions to the *pro forma* SGIA will permit the transmission provider to coordinate with the small generating facility to set ride through settings appropriate for those conditions, in accordance with Good Utility Practice and the appropriate technical standards. For facilities with a lower risk of forming an unintentional island, the transmission provider can implement a longer ride through requirement, in accordance with Good Utility Practice and the appropriate technical standards. We believe that the flexibility provided by section 1.5.7 allows for appropriate ride through requirements while recognizing the need to address any safety concerns.

B. Referencing Specific Technical Standards

1. NOPR Proposal

29. In the NOPR, the Commission proposed to avoid prescriptive frequency and voltage ride through requirements to allow for the development of appropriate system-specific standards, noting that the standards can be based on work developed by recognized standards settings bodies, such as IEEE.

2. Comments

30. Commenters request that the proposed rule contain explicit references to standards such as the Reliability Standards and IEEE and UL standards.[39] The ISO/RTO Council states that Reliability Standards already provide requirements for coordination

[39] ISO/RTO Council Comments at 7.

of automatic under-frequency generator tripping with automatic under-frequency load shedding programs that should be incorporated in the new ride through requirements. The ISO/RTO Council suggests that the *pro forma* SGIA explicitly reference Reliability Standard PRC-024 (Generator Frequency and Voltage Protective Relay Settings) and applicable regional Reliability Standards as part of the definition of "Good Utility Practice" and for the coordination of automatic generator tripping with automatic load shedding.[40] The ISO/RTO Council also recommends that the *pro forma* SGIA refer to the Reliability Standards and regional Reliability Standards for coordination of automatic generator tripping with automatic load shedding, and as appropriate, permit individual transmission providers to also reference their automatic load-shed program.

31. Commenters assert that specifying certain technical standards would be beneficial for consistent enforceability; specifically, some commenters suggest that the *pro forma* SGIA reference IEEE and UL 1741 standards to describe "Good Utility Practice."[41] EPRI and IEEE comment that failure to harmonize ride through requirements with the proposed draft IEEE 1547 requirements may introduce confusion and ultimately delay testing and compliance, exposing the electric system to an increased reliability risk.[42] PNM recognizes that there are challenges to developing specific settings applicable to

[40] *Id*. at 6-7.

[41] PNM Comments at 3; EPRI Comments at 13; IEEE Comments at 2.

[42] EPRI Comments at 13; IEEE Comments at 2.

all small generating facilities.[43] However, PNM states that the Commission should still consider documenting some ride through expectation similar to those outlined in the LGIA requirements. PNM requests that the *pro forma* SGIA revisions consider a minimum ride through duration based on fault clearing times and a minimum voltage. PNM also requests that the Commission specify the location where the frequency and voltage measurements are taken to comply with the requirements, such as the point of interconnection.

32. SoCal Edison observes that the California Public Utilities Commission (CPUC) has established, through its retail Rule 21 tariff, smart inverter requirements for small generators interconnecting to the distribution systems of California's investor owned utilities, and low/high voltage ride through and low/high frequency ride through are part of the new required capabilities for small generators.[44] SoCal Edison explains that the CPUC ordered all investor owned utilities "to seek approval as may be needed for conforming changes to harmonize their federal wholesale Tariffs interconnection specifications with the revisions to Electric Tariff Rule 21."[45]

3. Commission Determination

33. We are not persuaded by commenters' arguments for the need to reference specific technical standards and decline to incorporate by reference any specific standard

[43] PNM Comments at 2.

[44] SoCal Edison Comments at 3.

[45] *Id*.

into the *pro forma* SGIA or to specify ride through duration and voltage and frequency levels. We therefore decline to modify the NOPR proposal in this regard.

34. To accommodate the differences in voltage and frequency ride through capabilities inherent in the different generation technologies, we believe that requiring basic performance expectations without explicitly specifying the duration or voltage and frequency levels allows the flexibility to apply appropriate ride through settings with coordination and approval of the transmission operator. As EPRI and IEEE note, the ride through requirement framework in the draft IEEE Standard 1547 is being structured along "performance categories" that take into account the technological differences of various types of small generating facilities. Once finalized, IEEE Standard 1547 may be used as a technical guide to meet the requirements adopted herein. Until revisions to IEEE Standard 1547 are finalized, however, transmission providers and affected interconnection customers must coordinate appropriate alternative frequency and voltage ride through settings.

35. Furthermore, as a pragmatic matter, by setting minimum ride through capability requirements that are not tied to a specific standard, the requirements in section 1.5.7 of the *pro forma* SGIA would remain applicable following any updates from IEEE Standard 1547 or other applicable standards, without having to modify the *pro forma* SGIA each time any such standard is updated.

36. In response to PNM's clarification request, we clarify that the point of interconnection is the appropriate place to measure frequency and voltage to comply with the ride through requirements.

C. Regional Differences

1. NOPR Proposal

37. The Commission proposed to permit RTOs and ISOs to seek "independent entity variations" from the proposed revisions to the *pro forma* SGIA.

2. Comments

38. Multiple commenters support the Commission's proposal to permit RTOs and ISOs to seek "independent entity variations" from the proposed revisions to the *pro forma* SGIA.[46]

39. Trade Associations request that the Commission also affirm the ability of transmission providers that are not members of RTOs or ISOs to seek variations from the *pro forma* SGIA to ensure consistency with regional reliability requirements. Trade Associations explain that differences in resource penetration and configuration (such as state renewable portfolio standards or wind generation in remote locations) have led to regional reliability requirements. Trade Associations note that the Commission recognized in Order No. 2003 that such regional reliability requirements might justify variations to *pro forma* interconnection agreements and procedures.[47] SoCal Edison believes that, to the extent that some regions may need additional time to implement the

[46] Trade Associations Comments at 12-13; SoCal Edison Comments at 4; ISO/RTO Council Comments at 6.

[47] Trade Associations Comments at 12-13.

proposed ride through requirements on small generating facilities, the Commission should grant such time.[48]

3. Commission Determination

40. We adopt the NOPR proposal and permit ISOs and RTOs to seek "independent entity variations" from revisions to the *pro forma* SGIA.[49] Also, as proposed in the NOPR, if a transmission provider seeks a deviation from section 1.5.7 of the *pro forma* SGIA, it must demonstrate that the deviation is consistent with or superior to the principles set forth in this Final Rule.

41. In addition, we clarify that we will also consider requests for "regional reliability variations," provided that such requests are supported by references to regional Reliability Standards, explain why these regional Reliability Standards support the requested variation, and include the text of the referenced Reliability Standards.[50] While some regions currently have greater penetration of small generation facilities than others, we are acting now to set a national minimum ride through capability before future increases in deployment of small generation facilities.

[48] SoCal Edison Comments at 4.

[49] *See* Order No. 792, 145 FERC ¶ 61,159 at P 274 (citing Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 822-827).

[50] *See id*. P 273 (citing Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 546).

IV. Compliance and Implementation

42. Section 35.28(f)(1) of the Commission's regulations requires every public utility with a non-discriminatory open access transmission tariff OATT on file to also have an SGIA on file with the Commission.[51]

43. We reiterate that the requirements of this Final Rule apply to all newly interconnecting small generating facilities that execute or request the unexecuted filing of an SGIA on or after the effective date of this Final Rule as well as existing interconnection customers that, pursuant to a new interconnection request, execute or request the unexecuted filing of a new or modified SGIA on or after the effective date.

44. We require each public utility transmission provider that has an SGIA within its OATT to submit a compliance filing within 65 days following publication in the Federal Register.[52] The compliance filing must demonstrate that it meets the requirements set forth in this proposal.

45. The Commission recently issued Order No. 827, a final rule in Docket No. RM16-1-000, directing transmission providers to submit SGIA revisions related to reactive

[51] 18 CFR 35.28(f)(1).

[52] For purposes of this Final Rule, a public utility is a utility that owns, controls, or operates facilities used for transmitting electric energy in interstate commerce, as defined by the FPA. *See* 16 U.S.C. 824(e). A non-public utility that seeks voluntary compliance with the reciprocity condition of an OATT may satisfy that condition by filing an OATT, which includes an SGIA.

power requirements to the Commission.[53] Those compliance filings are due to the Commission on September 21, 2016. To facilitate administrative efficiency, we will require the compliance filings for this Final Rule and Order No. 827 to be filed in one combined filing. Once this Final Rule is published in the Federal Register, the Commission will provide a short extension to the compliance dates in both proceedings such that the compliance dates are the same.

46. As discussed above, we are not requiring changes to interconnection agreements that were executed prior to the effective date of this Final Rule. Instead, the requirements of this Final Rule apply to newly interconnecting small generating facilities that execute or request the unexecuted filing of an interconnection agreement on or after the effective date. The requirements of this Final Rule also apply to existing small generating facilities that, pursuant to a new interconnection request, require new or modified interconnection agreements that are executed or requested to be filed unexecuted on or after the effective date.

47. Some public utility transmission providers may have provisions in their existing SGIAs or other document(s) subject to the Commission's jurisdiction that the Commission has deemed to be consistent with or superior to the *pro forma* SGIA or are permissible under the independent entity variation standard or regional reliability

[53] *Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 81 Fed. Reg. 40,793 (Jun. 23, 2016), 155 FERC ¶ 61,277 (2016).

standard.[54] Where these provisions would be modified by this Final Rule, public utility transmission providers must either comply with this Final Rule or demonstrate that these previously-approved variations continue to be consistent with or superior to the *pro forma* SGIA as modified by this Final Rule or continue to be permissible under the independent entity variation standard or regional reliability standard.[55]

48. We find that transmission providers that are not public utilities must adopt the requirements of this Final Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[56]

V. Information Collection Statement

49. The following collection of information contained in this Final Rule is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995.[57] OMB's regulations require approval

[54] *See* Order No. 792, 145 FERC ¶ 61,159 at P 270.

[55] *See* 18 CFR 35.28(f)(1)(i).

[56] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,760-63 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[57] 44 U.S.C. 3507(d).

of certain information collection requirements imposed by agency rules.[58] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this Final Rule will not be penalized for failing to respond to this collection of information unless the collection of information displays a valid OMB control number.

50. The reforms adopted in this Final Rule revise the Commission's *pro forma* SGIA in accordance with section 35.28(f)(1) of the Commission's regulations.[59] This Final Rule applies to all newly interconnecting small generating facilities that execute or request the unexecuted filing of an SGIA on or after the effective date of this Final Rule as well as existing interconnection customers that, pursuant to a new interconnection request, execute or request the unexecuted filing of a new or modified SGIA on or after the effective date, to ensure frequency ride through capability and voltage ride through capability in accordance with good utility practice and consistent with any standards and guidelines that are applied to other generating facilities in the balancing authority area on a comparable basis. The reforms adopted in this Final Rule would require filings of SGIAs with the Commission. The Commission anticipates the revisions required by this Final Rule, once implemented, will not significantly change existing burdens on an ongoing basis. With regard to those public utility transmission providers that believe that they already comply with the revisions adopted in this Final Rule, they can demonstrate

[58] 5 CFR 1320.11.

[59] 18 CFR 35.28(f)(1).

their compliance in the filing required 65 days after the effective date of this Final Rule. The Commission will submit the proposed reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[60]

51. While the Commission expects the revisions adopted in this Final Rule will provide significant benefits, the Commission understands that implementation would entail some costs. The Commission solicited comments on the accuracy of provided burden and cost estimates and any suggested methods for minimizing the respondents' burdens. The Commission did not receive any comments concerning its burden or cost estimates. As explained above, we will require the compliance filings for this Final Rule and Order No. 827 to be filed in one combined filing. We expect that this will reduce the burden on public utility transmission providers at the time the Commission gives notice of the extension of the compliance date and requirement to combine compliance filings.

Burden Estimate: The Commission believes that the burden estimates below are representative of the average burden on respondents. The estimated burden and cost for the requirements adopted in this Final Rule follow.[61]

[60] 44 U.S.C. 3507(d).

[61] Commission staff estimates that industry is similarly situated in terms of hourly cost (wages plus benefits). Based on the Commission 2016 average cost (wages plus benefits), $74.50/hour is used.

FERC 516A revisions in RM16-8					
	No. of Respondents[62] (1)	**Annual No. of Responses per Respondent (2)**	**Total No. of Responses (1)*(2)=(3)**	**Average Burden (Hrs.) & Cost ($) Per Response (4)**	**Total Annual Burden Hrs. & Total Annual Cost ($) (3)*(4)=(5)**
Conforming SGIA changes to incorporate revisions	118	1	118	7.5 hrs.; $558.75	885 hrs.; $65,932.50
Total			118	7.5 hrs.; $558.75	885 hrs.; $65,932.50

Cost to Comply: The Commission has projected the additional cost of compliance as follows:[63]

- Year 1: $65,932.50 for all affected entities ($558.75/utility)
- Year 2 and subsequent years: $0

After implementation in Year 1, the reforms proposed in this Final Rule would be complete.

Title: FERC-516A, Standardization of Small Generator Interconnection Agreements and Procedures.

[62] Number of Applicable Registered Entities.

[63] The costs for Year 1 would consist of filing proposed changes to the *pro forma* SGIA with the Commission within 65 days of the effective date of the final revision plus initial implementation. The Commission does not expect any ongoing costs beyond the initial compliance in Year 1.

Action: Revision of currently approved collection of information.

OMB Control No.: 1902-0203

Respondents for this Rulemaking: Businesses or other for profit and/or not-for-profit institutions.

Frequency of Information: One-time during Year 1.

Necessity of Information: The Commission adopts changes to the *pro forma* SGIA in order to more efficiently and cost-effectively interconnect generating facilities no larger than 20 MW (small generating facilities) to Commission-jurisdictional transmission systems. The purpose of this Final Rule is to revise the *pro forma* SGIA so small generating facilities can be reliably and efficiently integrated into the electric grid and to ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. This Final Rule seeks to achieve this goal by amending the *pro forma* SGIA to include new section 1.5.7.

Internal Review: The Commission has reviewed the changes and has determined that the changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements.

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

53. Comments on the collection of information and the associated burden estimate in the Final Rule should be sent to the Commission in this docket and may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission], at the following e-mail address: oira_submission@omb.eop.gov. Please reference OMB Control No. 1902-0203 and the docket number of this rulemaking in your submission.

VI. Regulatory Flexibility Act

54. The Regulatory Flexibility Act of 1980 (RFA)[64] generally requires a description and analysis of rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

55. The Small Business Administration (SBA) revised its size standards (effective January 22, 2014) for electric utilities from a standard based on megawatt hours to a standard based on the number of employees, including affiliates. Under SBA's

[64] 5 U.S.C. 601-612.

standards, some transmission owners will fall under the following category and associated size threshold: electric bulk power transmission and control, at 500 employees.[65]

56. The Commission estimates that the total number of public utility transmission providers that would have to modify the SGIAs within their currently effective OATTs is 118. Of these, the Commission estimates that approximately 43% are small entities. The Commission estimates the average cost to each of these entities will be minimal, requiring on average 7.5 hours or $558.75. According to SBA guidance, the determination of significance of impact "should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors."[66] The Commission does not consider the estimated burden to be a significant economic impact. As a result, the Commission certifies that the reforms adopted in this Final Rule would not have a significant economic impact on a substantial number of small entities.

VII. Environmental Analysis

57. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect

[65] 13 CFR 121.201, Sector 22 (Utilities), NAICS code 221121 (Electric Bulk Power Transmission and Control).

[66] U. S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act*, at 18 (May 2012), https://www.sba.gov/sites/default/files/advocacy/rfaguide_0512_0.pdf.

on the human environment.[67] As we stated in the NOPR, the Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for the revisions adopted in this Final Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[68] The revisions adopted in this Final Rule would update and clarify the application of the Commission's standard interconnection requirements to small generating facilities.

58. Therefore, this Final Rule falls within the categorical exemptions provided in the Commission's regulations, and as a result neither an Environmental Impact Statement nor an Environmental Assessment is required.

VIII. Document Availability

59. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal

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

[68] 18 CFR 380.4(a)(15).

business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

60. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.

61. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

IX. Effective Date and Congressional Notification

62. The Final Rule is effective [**INSERT DATE 65 days from publication in FEDERAL REGISTER**]. However, as noted above, the requirements of this Final Rule will apply only to all newly interconnecting small generating facilities that execute or request the unexecuted filing of an SGIA on or after the effective date of this Final Rule as well as existing interconnection customers that, pursuant to a new interconnection request, execute or request the unexecuted filing of a new or modified SGIA on or after the effective date. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this Final Rule is not a "major rule" as defined in section 351 of the Small Business

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

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A

List of Substantive Commenters (RM16-8-000)

Bonneville	Bonneville Power Administration
Trade Associations	Edison Electric Institute/American Public Power Association/Large Public Power Council /National Rural Electric Cooperative Association
EPRI	Electric Power Research Institute
Idaho Power	Idaho Power Company
IEEE	Institute of Electrical and Electronics Engineers
ISO/RTO Council	ISO/RTO Council
NERC	North American Electric Reliability Corporation
PG&E	Pacific Gas and Electric Company
Peak Reliability	Peak Reliability
PNM	Public Service Company of New Mexico
SoCal Edison	Southern California Edison Company

In addition, Entergy Services, Inc. submitted non-substantive comments.

156 FERC ¶ 61,050
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM15-14-002; Order No. 829]

Revised Critical Infrastructure Protection Reliability Standards

(Issued July 21, 2016)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) directs the North American Electric Reliability Corporation to develop a new or modified Reliability Standard that addresses supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations. The new or modified Reliability Standard is intended to mitigate the risk of a cybersecurity incident affecting the reliable operation of the Bulk-Power System.

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

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SUPPLEMENTARY INFORMATION:

156 FERC ¶ 61,050
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Revised Critical Infrastructure Protection Reliability Standards — Docket No. RM15-14-002

ORDER NO. 829

FINAL RULE

(Issued July 21, 2016)

1. Pursuant to section 215(d)(5) of the Federal Power Act (FPA),[1] the Commission directs the North American Electric Reliability Corporation (NERC) to develop a new or modified Reliability Standard that addresses supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations. The new or modified Reliability Standard is intended to mitigate the risk of a cybersecurity incident affecting the reliable operation of the Bulk-Power System.

2. The record developed in this proceeding supports our determination under FPA section 215(d)(5) that it is appropriate to direct the creation of mandatory requirements

[1] 16 U.S.C. 824o(d)(5).

that protect aspects of the supply chain that are within the control of responsible entities and that fall within the scope of our authority under FPA section 215. Specifically, we direct NERC to develop a forward-looking, objective-based Reliability Standard to require each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations.[2] The new or modified Reliability Standard should address the following security objectives, discussed in detail below: (1) software integrity and authenticity; (2) vendor remote access; (3) information system planning; and (4) vendor risk management and procurement controls. In making this directive, the Commission does not require NERC to impose any specific controls, nor does the Commission require NERC to propose "one-size-fits-all" requirements. The new or modified Reliability Standard should instead require responsible entities to develop a plan to meet the four objectives, or some equally efficient and effective means to meet these objectives, while providing flexibility to responsible entities as to how to meet those objectives.

[2] *Revised Critical Infrastructure Protection Reliability Standards*, Notice of Proposed Rulemaking, 80 Fed. Reg. 43,354 (Jul. 22, 2015), 152 FERC ¶ 61,054, at P 66 (2015) (NOPR).

I. Background

A. Section 215 and Mandatory Reliability Standards

3. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[3] Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[4] and subsequently certified NERC.[5]

B. Notice of Proposed Rulemaking

4. The NOPR, *inter alia*, identified as a reliability concern the potential risks to bulk electric system reliability posed by the "supply chain" (i.e., the sequence of processes involved in the production and distribution of, *inter alia*, industrial control system hardware, software, and services). The NOPR explained that changes in the bulk electric system cyber threat landscape, exemplified by recent malware campaigns targeting supply chain vendors, have highlighted a gap in the Critical Infrastructure Protection

[3] 16 U.S.C. 824o(e).

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

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

(CIP) Reliability Standards.[6] To address this gap, the NOPR proposed to direct that NERC develop a forward-looking, objective-driven Reliability Standard that provides security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations.[7]

5. Recognizing that developing supply chain management requirements would likely be a significant undertaking and require extensive engagement with stakeholders to define the scope, content, and timing of the Reliability Standard, the Commission sought comment on: (1) the general proposal to direct that NERC develop a Reliability Standard to address supply chain management; (2) the anticipated features of, and requirements that should be included in, such a standard; and (3) a reasonable timeframe for development of a Reliability Standard.[8]

6. In response to the NOPR, thirty-four entities submitted comments on the NOPR proposal regarding supply chain risk management. A list of these commenters appears in Appendix A.

C. January 28, 2016 Technical Conference

7. On January 28, 2016, Commission staff led a Technical Conference to facilitate a dialogue on supply chain risk management issues that were identified by the Commission

[6] NOPR, 152 FERC ¶ 61,054 at P 63.

[7] *Id.* P 66.

[8] *Id.*

in the NOPR. The January 28 Technical Conference addressed: (1) the need for a new or modified Reliability Standard; (2) the scope and implementation of a new or modified Reliability Standard; and (3) current supply chain risk management practices and collaborative efforts.

8. Twenty-four entities representing industry, government, vendors, and academia participated in the January 28 Technical Conference through written comments and/or presentations.[9]

9. We address below the comments submitted in response to the NOPR and comments made as part of the January 28 Technical Conference.

II. Discussion

10. Pursuant to section 215(d)(5) of the FPA, the Commission determines that it is appropriate to direct NERC to develop a new or modified Reliability Standard(s) that address supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations.[10] Based on the comments received in response to the NOPR and at the technical conference, we determine that the record in this proceeding supports the development of

[9] Written presentations at the January 28, 2016 Technical Conference and the Technical Conference transcript referenced in this Final Rule are accessible through the Commission's eLibrary document retrieval system in Docket No. RM15-14-000.

[10] 16 U.S.C. 824o(d)(5) ("The Commission . . . may order the [ERO] to submit to the Commission a proposed reliability standard or a modification to a reliability standard that addresses as specific matter if the Commission considers such a new or modified reliability standard appropriate to carry out this section.").

mandatory requirements for the protection of aspects of the supply chain that are within the control of responsible entities and that fall within the scope of our authority under FPA section 215.

11. In its NOPR comments, NERC acknowledges that "supply chains for information and communications technology and industrial control systems present significant risks to [Bulk-Power System] security, providing various opportunities for adversaries to initiate cyberattacks."[11] Several other commenters also recognized the risks posed to the bulk electric system by supply chain security issues and generally support, or at least do not oppose, Commission action to address the reliability gap.[12] For example, in prepared remarks submitted for the January 28 Technical Conference, one panelist noted that attacks targeting the supply chain are on the rise, particularly attacks involving third party service providers.[13] In addition, it was noted that, while many responsible entities are already independently assessing supply chain risks and asking vendors to address the

[11] NERC NOPR Comments at 8.

[12] *See* Peak NOPR Comments at 3-6; ITC NOPR Comments at 13-15; CyberArk NOPR Comments at 4; Ericsson NOPR Comments at 2; Isologic and Resilient Societies Joint NOPR Comments at 9-12; ACS NOPR Comments at 4; ISO NE NOPR Comments at 2-3; NEMA NOPR Comments at 1-2.

[13] Olcott Technical Conference Comments at 1-2.

risks, these individual efforts are likely to be less effective than a mandatory Reliability Standard.[14]

12. We recognize, however, that most commenters oppose development of Reliability Standards addressing supply chain management for various reasons. These commenters contend that Commission action on supply chain risk management would, among other things, address or influence activities beyond the scope of the Commission's FPA section 215 jurisdiction.[15] Commenters also assert that the existing CIP Reliability Standards adequately address potential risks to the bulk electric system from supply chain issues.[16] In addition, commenters claim that responsible entities have minimal control over their suppliers and are not able to identify all potential vulnerabilities associated with each of their products or parts; therefore, even if a responsible entity identifies a vulnerability created by a supplier, the responsible entity does not necessarily have any authority,

[14] Galloway Technical Conference Comments at 1 ("…ISO-NE supports the Commission's proposal to direct NERC to develop requirements relating to supply chain risk management. We believe that the risks to the reliability of the Bulk Electric System that result from compromised third-party software are real, significant and largely unaddressed by existing reliability standards. While many public utilities are already assessing these risks and asking vendors to address them, these one-off efforts are far less likely to be effective than an industry-wide reliability standard.").

[15] *See* Trade Associations NOPR Comments at 24; Southern NOPR Comments at 14-16; CEA NOPR Comments at 4-5; NIPSCO NOPR Comments at 7.

[16] *See* Trade Associations NOPR Comments at 20-25; Gridwise NOPR Comments at 3; Arkansas NOPR Comments at 6; G&T Cooperatives NOPR Comments at 8-9; NEI NOPR Comments at 3-5; NIPSCO NOPR Comments at 5-6; Luminant NOPR Comments at 4-5; SCE NOPR Comments at 4.

influence or means to require the supplier to apply mitigation.[17] Other commenters argue that the Commission's proposal may unintentionally inhibit innovation.[18] A number of commenters assert that voluntary guidelines would be more effective at addressing the Commission's concerns.[19] Finally, commenters are concerned that the contractual flexibility necessary to effectively address supply chain concerns does not fit well with a mandatory Reliability Standard.[20]

13. As discussed below, we conclude that our directive falls within the Commission's authority under FPA section 215. We also determine that, notwithstanding the concerns raised by commenters opposed to the NOPR proposal, it is appropriate to direct the development of mandatory requirements to protect industrial control system hardware, software, and computing and networking services associated with bulk electric system operations. Many of the commenters' concerns are addressed by the flexibility inherent in our directive to develop a forward-looking, objective-based Reliability Standard that includes specific security objectives that a responsible entity must achieve, but affords flexibility in how to meet these objectives. The Commission does not require NERC to

[17] *See* Arkansas NOPR Comments at 5-6; G&T Cooperatives NOPR Comments at 9; Trade Associations NOPR Comments at 25.

[18] *See* Arkansas NOPR Comments at 6; G&T Cooperatives NOPR Comments at 9; NERC NOPR Comments at 13.

[19] *See* Trade Associations NOPR Comments at 23; Southern NOPR Comments at 13; AEP NOPR Comments at 5; NextEra NOPR Comments at 4-5; Luminant NOPR Comments at 5.

[20] *See* Arkansas NOPR Comments at 6; Southern NOPR Comments at 13.

impose any specific controls nor does the Commission require NERC to propose "one-size-fits-all" requirements. The new or modified Reliability Standard should instead require responsible entities to develop a plan to meet the four objectives, or some equally efficient and effective means to meet these objectives, while providing flexibility to responsible entities as to how to meet those objectives. Moreover, our directive comports well with the NOPR comments submitted by NERC, in which NERC explained what it believes would be the features of a workable supply chain management Reliability Standard.[21]

14. We address below the following issues raised in the NOPR, NOPR comments, and January 28 Technical Conference comments: (1) the Commission's authority to direct the ERO to develop supply chain management Reliability Standards under FPA section 215(d)(5); and (2) the need for supply chain management Reliability Standards, including the risks posed by the supply chain, objectives of a supply chain management Reliability Standard, existing CIP Reliability Standards, and responsible entities' ability to affect the supply chain.

[21] NERC NOPR Comments at 8-9. The record evidence on which the directive in this Final Rule is based is either comparable or superior to past instances in which the Commission has directed, pursuant to FPA section 215(d)(5), that NERC propose a Reliability Standard to address a gap in existing Reliability Standards. *See, e.g.*, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014) (directing, without seeking comment, that NERC develop proposed Reliability Standards to protect against physical security risks related to the Bulk-Power System).

A. Commission Authority to Direct the ERO to Develop Supply Chain Management Reliability Standards Under FPA Section 215(d)(5)

NOPR

15. In the NOPR, the Commission stated that it anticipates that a Reliability Standard addressing supply chain management security would, *inter alia*, respect FPA Section 215 jurisdiction by only addressing the obligations of responsible entities and not directly imposing obligations on suppliers, vendors, or other entities that provide products or services to responsible entities.[22]

Comments

16. Commenters contend that the Commission's proposal to direct NERC to develop mandatory Reliability Standards to address supply chain risks could exceed the Commission's jurisdiction under FPA section 215. The Trade Associations state that the NOPR discussion "appears to suggest a new mandate, over and above Section 215 for energy security, integrity, quality, and supply chain resilience, and the future acquisition of products and services."[23] The Trade Associations assert that the Commission's NOPR proposal does not provide any reasoning that connects energy security and integrity with reliable operations for Bulk-Power System reliability. The Trade Associations seek

[22] NOPR, 152 FERC ¶ 61,054 at P 66.

[23] Trade Associations NOPR Comments at 24.

clarification that the Commission does not intend to define energy security as a new policy mandate.[24]

17. Southern states that it agrees with the Trade Associations that expanding the focus of the NERC Reliability Standards "to include concepts such as security, integrity, and supply chain resilience is beyond the statutory authority granted in Section 215."[25] Southern contends that while these areas "have an impact on the reliable operation of the bulk power system, […] they are areas that are beyond the scope of [the Commission's] jurisdiction under Section 215."[26] NIPSCO raises a similar argument, stating that the existing CIP Reliability Standards should address the Commission's concerns "without involving processes and industries outside of the Commission's jurisdiction under section 215 of the Federal Power Act."[27]

18. Southern questions how a mandatory Reliability Standard that achieves all of the objectives specified in the NOPR "could effectively address [the Commission's] concerns and still stay within the bounds of [the Commission's] scope and mission under Section 215."[28] Southern asserts that "a reading of Section 215 indicates that [the Commission's]

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[24] *Id.*

[25] Southern NOPR Comments at 16.

[26] Southern NOPR Comments at 16; *see also* Trade Association NOPR Comments at 24.

[27] NIPSCO NOPR Comments at 7.

[28] Southern NOPR Comments at 14-15.

mission and authority under Section 215 is focused on the *operation* of the bulk power system elements, not on the acquisition of those elements and associated procurement practices."[29] In support of its assertion, Southern points to the definition in FPA section 215 of "reliability standard," noting the use and meaning of the terms "reliable operation" and "operation." Southern contends that "Section 215 standards should ensure that a given BES Cyber System asset is protected from vulnerabilities once connected to the BES, and should not be concerned about how the Responsible Entity works with its vendors and suppliers to ensure such reliability (such as higher financial incentives or greater contractual penalties)."[30]

19. The Trade Associations and Southern also observe that, while the NOPR indicates that the Commission has no direct oversight authority over third-party suppliers or vendors and cannot indirectly assert authority over them through jurisdictional entities, the NOPR proposal appears to assert that authority.[31] The Trade Associations maintain that such an extension of the Commission's authority would be unlawful and, therefore, seek clarification that "the Commission will avoid seeking to extend its authority since such an extension would set a troubling precedent."[32] CEA raises a concern that the

[29] *Id.* at 15 (emphasis in original).

[30] *Id.* at 16.

[31] Trade Associations NOPR Comments at 24-25; Southern NOPR Comments at 17; *see also* Trade Associations Post-Technical Conference Comments at 20-21.

[32] Trade Associations NOPR Comments at 24-25.

NOPR proposal "appears to lend itself to the interpretation that authority is indirectly being asserted over non-jurisdictional entities."[33]

20. The Trade Associations also maintain that the Commission's use of the term "industrial control system" in the scope of its proposal suggests that the Commission is seeking to address issues beyond CIP and cybersecurity-related issues. The Trade Associations seek clarification that the Commission does not intend for NERC broadly to address industrial control systems, such as fuel procurement and delivery systems or system protection devices, but intends for its proposal to be limited to CIP and cybersecurity-related issues.[34]

Discussion

21. We are satisfied that FPA section 215 provides the Commission with the authority to direct NERC to address the reliability gap concerning supply chain management risks identified in the NOPR. We reject the contention that our directive could be read to address issues outside of the Commission's FPA section 215 jurisdiction. However, to be clear, we reiterate the statement in the NOPR that any action taken by NERC in response to the Commission's directive to address the supply chain-related reliability gap should respect "section 215 jurisdiction by only addressing the obligations of responsible entities" and "not directly impose obligations on suppliers, vendors or other entities that

[33] CEA NOPR Comments at 5.

[34] Trade Associations NOPR Comments at 25.

provide products or services to responsible entities."[35] The Commission expects that NERC will adhere to this instruction as it works with stakeholders to develop a new or modified Reliability Standard to address the Commission's directive. As discussed below, we reject the remaining comments regarding the Commission's authority to direct the development of supply chain management Reliability Standards under FPA section 215(d)(5).

22. Our directive does not suggest, as the Trade Associations contend, a new mandate above and beyond FPA section 215. The Commission's directive to NERC to address supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations is not intended to "define 'energy security' as a new policy mandate" under the CIP Reliability Standards.[36] Instead, our directive is meant to enhance bulk electric system cybersecurity by addressing the gap in the CIP Reliability Standards identified in the NOPR relating to supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations. This directive is squarely within the statutory definition of a "reliability standard," which includes requirements for "cybersecurity protection." [37]

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[35] NOPR, 152 FERC ¶ 61,054 at P 66.

[36] *See* Trade Associations NOPR Comments at 24.

[37] *See* 16 U.S.C. 824o(a)(3) (defining "reliability standard" to mean "a requirement, approved by the Commission under [section 215 of the FPA] to provide for

(continued…)

23. We reject Southern's argument that FPA section 215 limits the scope of the NERC Reliability Standards to "ensur[ing] that a given BES Cyber System asset is protected from vulnerabilities once connected" to the bulk electric system.[38] While Southern's comment implies that the Commission should only be concerned with real-time operations based on the definition of the term "reliable operation," the definition of "reliability standard" in FPA section 215 also includes requirements for "the design of planned additions or modifications" to bulk electric system facilities "necessary to provide for reliable operation of the bulk-power system."[39] Moreover, as noted, FPA section 215 is clear that maintaining reliable operation also includes protecting the bulk electric system from cybersecurity incidents.[40] Indeed, our findings and directives in the Final Rule are intended to better protect the Bulk-Power System from potential cybersecurity incidents that could adversely affect reliable operation of the Bulk-Power System. Accordingly, we would not be carrying out our obligations under FPA section 215 if the Commission determined that cybersecurity incidents resulting from gaps in supply chain risk management were outside the scope of FPA section 215.

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the reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, *including cybersecurity protection*, and *the design of planned additions or modifications to such facilities* to the extent necessary to provide for reliable operation…") (emphasis added).

[38] *See* Southern NOPR Comments at 16.

[39] *See* 16 U.S.C. 824o(a)(4) (defining "reliable operation"); *see also* 16 U.S.C. 824o(a)(3).

[40] *See* 16 U.S.C. 824o(a)(4).

24. With regard to concerns that the NOPR's use of the term "industrial control system" signals the Commission's intent to address issues beyond the CIP Reliability Standards or cybersecurity controls, we clarify that our directive is only intended to address the protection of hardware, software, and computing and networking services associated with bulk electric system operations from supply chain-related cybersecurity threats and vulnerabilities.

B. Need for a New or Modified Reliability Standard

1. Cyber Risks Posed by the Supply Chain

NOPR

25. In the NOPR, the Commission observed that the global supply chain, while providing an opportunity for significant benefits to customers, enables opportunities for adversaries to directly or indirectly affect the operations of companies that may result in risks to the end user. The NOPR identified supply chain risks including the insertion of counterfeits, unauthorized production, tampering, theft, or insertion of malicious software, as well as poor manufacturing and development practices. The NOPR pointed to changes in the bulk electric system cyber threat landscape, evidenced by recent malware campaigns targeting supply chain vendors, which highlighted a gap in the protections under the current CIP Reliability Standards.[41]

26. Specifically, the NOPR identified two focused malware campaigns identified by the Department of Homeland Security's Industry Control System - Computer Emergency

[41] NOPR, 152 FERC ¶ 61,054 at PP 61-62.

Readiness Team (ICS-CERT) in 2014.[42] The NOPR stated that this new type of malware campaign is based on the injection of malware while a product or service remains in the control of the hardware or software vendor, prior to delivery to the customer.[43]

Comments

27. NERC acknowledges the NOPR's concerns regarding the threats posed by supply chain management risks to the Bulk-Power System. NERC states that "the supply chains for information and communications technology and industrial control systems present significant risks to [Bulk-Power System] security, providing various opportunities for adversaries to initiate cyberattacks."[44] NERC further explains that "supply chains risks are … complex, multidimensional, and constantly evolving, and may include, as the Commission states, insertion of counterfeits, unauthorized production, tampering, theft, insertion of malicious software and hardware, as well as poor manufacturing and development practices."[45] NERC states, however, that as to these supply chains, there

[42] *Id.* P 63 (citing ICS-CERT, *Alert: ICS Focused Malware (Update A)*, https://ics-cert.us-cert.gov/alerts/ICS-ALERT-14-176-02A; ICS-CERT, *Alert Ongoing Sophisticated Malware Campaign Compromising ICS (Update E)*, https://ics-cert.us-cert.gov/alerts/ICS-ALERT-14-281-01B). ICS-CERT is a division of the Department of Homeland Security that works to reduce risks within and across all critical infrastructure sectors by partnering with law enforcement agencies and the intelligence community.

[43] NOPR, 152 FERC ¶ 61,054 at P 63.

[44] NERC NOPR Comments at 8.

[45] *Id.* at 10.

are "significant challenges to developing a mandatory Reliability Standard consistent with [FPA] Section 215…."[46]

28. IRC, Peak, Idaho Power, CyberArk, NEMA, Resilient Societies and other commenters share the NOPR's concern that supply chain risks pose a threat to bulk electric system reliability. IRC states that it supports the Commission's efforts to address the risks associated with supply chain management.[47] Peak explains that "the security risk of supply chain management is a real threat, and … a CIP standard for supply chain management may be necessary."[48] Peak notes, for example, that it is possible for a malware campaign to infect industrial control software with malicious code while the product or service is in the control of the hardware and software vendor, and states that, "[w]ithout proper controls, the vendor may deliver this infected product or service, unknowingly passing the risk onto the utility industry customer."[49] Isologic and Resilient Societies comments that supply chain vulnerabilities are one of the most difficult areas of cybersecurity because, among other concerns, entities "are seldom aware of the risks [supply chain vulnerabilities] pose."[50]

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[46] *Id.* at 2.

[47] IRC NOPR Comments at 1-2.

[48] Peak NOPR Comments at 3.

[49] *Id.* at 3.

[50] Isologic and Resilient Societies Joint NOPR Comments at 9.

29. Idaho Power agrees "that the supply chain could pose an attack vector for certain risks to the bulk electric system."[51] CyberArk states that "infection of vendor web sites is just one of the potential ways a supply chain management attack could be executed" and notes that network communications links between a vendor and its customer could be used as well.[52] NEMA agrees with the NOPR that "keeping the electric sector supply chain free from malware and other cybersecurity risks is essential."[53] NEMA highlights a number of principles it represents as vendor best practices, and encourages the Commission and NERC to reference those principles as the effort to address supply chain risks progresses.[54]

30. Other commenters do not agree that the risks identified in the NOPR support the Commission's NOPR proposal. The Trade Associations, Southern, and NIPSCO contend that the two malware campaigns identified by ICS-CERT and cited in the NOPR do not actually represent a changed threat landscape that defines a reliability gap. Specifically, the Trade Associations state that the two identified malware campaigns "seek to inject malware, while a product is in the control of and in use by the customer and not, as the NOPR suggests, the vendor."[55] In support of this position, the Trade Associations note

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[51] Idaho Power NOPR Comments at 3.

[52] CyberArk NOPR Comments at 4.

[53] NEMA NOPR Comments at 1.

[54] *Id.* at 2.

[55] Trade Associations NOPR Comments at 20-21.

that the ICS-CERT mitigation measures for the two alerts "focused on the customer and do not address security controls, while the products are under control of the vendors."[56]

31. The Trade Associations and Southern also contend that there is no information from various NERC programs and activities that leads to a reasonable conclusion that supply chain management issues have caused events or disturbances on the bulk electric system.[57] Luminant states that it "does not perceive the same reliability gap that is expressed in the NOPR concerning risks associated with supply chain management" and contends that it is important to understand the potential risks and cost impacts related to any potential mitigation efforts before developing any additional security controls.[58] KCP&L states that it does not share the Commission's view of the supply chain-related reliability gap described in the NOPR and, therefore, does not support the Commission's proposal.[59]

Discussion

32. We find ample support in the record to conclude that supply chain management risks pose a threat to bulk electric system reliability. As NERC commented, "the supply chains for information and communications technology and industrial control systems

[56] Trade Associations NOPR Comments at 21; *see also* NIPSCO NOPR Comments at 6.

[57] Trade Associations NOPR Comments at 21; Southern Comments at 11.

[58] Luminant NOPR Comments at 4.

[59] KCP&L NOPR Comments at 7.

present significant risks to [Bulk-Power System] security, providing various opportunities for adversaries to initiate cyberattacks."[60] The malware campaigns analyzed by ICS-CERT and identified in the NOPR are only examples of such risks (i.e., supply chain attacks targeting supply chain vendors). Commenters identified additional supply chain-related threats,[61] including events targeting electric utility vendors.[62]

33. Even among the comments opposed to the NOPR, there is acknowledgment that supply chain reliability risks exist. The Trade Associations state that their "respective

[60] NERC NOPR Comments at 8.

[61] Commenters reference tools and information security frameworks, such as ES-C2M2, NIST-SP-800-161 and NIST-SP-800-53, which describe the scope of supply chain risk that could impact bulk electric system operations. *See* Department of Energy, Electricity Subsector Cybersecurity Capability Maturity Model (February 2014), http://energy.gov/sites/prod/files/2014/02/f7/ES-C2M2-v1-1-Feb2014.pdf; NIST Special Publication 800-161, *Supply Chain Risk Management Practices for Federal Information Systems and Organizations* at 51, http://nvlpubs.nist.gov/nistpubs/SpecialPublications/NIST.SP.800-161.pdf; NIST Special Publication 800-53, *Security and Privacy Controls for Federal Information Systems and Organizations*, http://nvlpubs.nist.gov/nistpubs/SpecialPublications/NIST.SP.800-53r4.pdf. These risks include the insertion of counterfeits, unauthorized production and modification of products, tampering, theft, intentional insertion of tracking software, as well as poor manufacturing and development practices. One technical conference participant noted that supply chain attacks can target either (1) the hardware/software components of a system (thereby creating vulnerabilities that can be exploited by a remote attacker) or (2) a third party service provider who has access to sensitive IT infrastructure or holds/maintains sensitive data. *See* Olcott Technical Conference Comments at 1.

[62] Olcott discusses two events targeting electric utility vendors and service providers. Olcott Technical Conference Comments at 2. Specific recent examples of attacks on third party vendors include: (1) unauthorized code found in Juniper Firewalls in 2015; (2) the 2013 Target incident involving stolen vendor credentials; (3) the 2015 Office of Personnel Management incident also involving stolen vendor credentials; and (4) two events targeting electric utility vendors. *See id.* at 1-4.

members have identified security issues associated with potential supply chain disruption or compromise as being a significant threat."[63] Recognizing that such risks exist, we reject the assertion by the Trade Associations and Southern that there is an inadequate basis for the Commission to take action because "[t]he Trade Associations can find nothing within various NERC programs and activities that lead to a reasonable conclusion that supply chain management issues have caused events or disturbances on the bulk power system."[64]

34. We disagree with the Trade Associations' arguments suggesting that the two malware campaigns identified in the NOPR do not represent a change in the threat landscape to the bulk electric system. First, while the Trade Associations are correct that the ICS-CERT alerts referenced in the NOPR describe remediation steps for customers to take in the event of a breach, the vulnerabilities exploited by those campaigns were the direct result of vendor decisions about: (1) how to deliver software patches to their customers and (2) the necessary degree of remote access functionality for their information and communications technology products.[65] Second, the malware campaigns also demonstrate that attackers have expanded their efforts to include the execution of

[63] Trade Associations NOPR Comments at 17.

[64] *See* Trade Associations NOPR Comments at 21.

[65] The ICS-CERT alert regarding ICS Focused Malware indicated that "the software installers for … vendors were infected with malware known as the Havex Trojan."

broad access campaigns targeting vendors and software applications, rather than just individual entities. The targeting of vendors and software applications with potentially broad access to BES Cyber Systems[66] marks a turning point in that it is no longer sufficient to focus protection strategies exclusively on post-acquisition activities at individual entities. Instead, we believe that attention should also be focused on minimizing the attack surfaces of information and communications technology products procured to support bulk electric system operations.

2. Objectives of a Supply Chain Management Reliability Standard

NOPR

35. The NOPR stated that the reliability goal of a supply chain risk management Reliability Standard should be a forward-looking, objective-driven Reliability Standard that encompasses activities in the system development life cycle: from research and development, design and manufacturing stages (where applicable), to acquisition, delivery, integration, operations, retirement, and eventual disposal of the responsible

[66] Cyber systems are referred to as "BES Cyber Systems" in the CIP Reliability Standards. The NERC Glossary defines BES Cyber Systems as "One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity." NERC Glossary of Terms Used in Reliability Standards (May 17, 2016) at 15 (NERC Glossary). The NERC Glossary defines "BES Cyber Asset" as "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." *Id.*

entity's information and communications technology and industrial control system supply chain equipment and services. The NOPR explained that the Reliability Standard should support and ensure security, integrity, quality, and resilience of the supply chain and the future acquisition of products and services.[67]

36. The NOPR recognized that, due to the breadth of the topic and the individualized nature of many aspects of supply chain management, a Reliability Standard pertaining to supply chain management security should:

- Respect FPA section 215 jurisdiction by only addressing the obligations of responsible entities. A Reliability Standard should not directly impose obligations on suppliers, vendors or other entities that provide products or services to responsible entities.
- Be forward-looking in the sense that the Reliability Standard should not dictate the abrogation or re-negotiation of currently-effective contracts with vendors, suppliers or other entities.
- Recognize the individualized nature of many aspects of supply chain management by setting goals (the "what"), while allowing flexibility in how a responsible entity subject to the Reliability Standard achieves that goal (the "how").

[67] NOPR, 152 FERC ¶ 61,054 at P 64.

- Given the types of specialty products involved and the diversity of acquisition processes, the Reliability Standard may need to allow exceptions (e.g., to meet safety requirements and fill operational gaps if no secure products are available).
- Provide enough specificity so that compliance obligations are clear and enforceable. In particular, the Commission anticipated that a Reliability Standard that simply requires a responsible entity to "have a plan" addressing supply chain management would not suffice. Rather, to adequately address the concerns identified in the NOPR, the Commission stated a Reliability Standard should identify specific controls.[68]

37. The NOPR recognized that, because security controls for supply chain management likely vary greatly with each responsible entity due to variations in individual business practices, the right set of supply chain management security controls should accommodate, *inter alia*, an entity's: (1) procurement process; (2) vendor relations; (3) system requirements; (4) information technology implementation; and (5) privileged commercial or financial information. As examples of controls that may be instructional in the development of any new Reliability Standard, the NOPR identified the following Supply Chain Risk Management controls from NIST SP 800-161: (1) Access Control Policy and Procedures; (2) Security Assessment Authorization; (3) Configuration Management; (4) Identification and Authentication; (5) System

[68] *Id.* P 66.

Maintenance Policy and Procedures; (6) Personnel Security Policy and Procedures; (7) System and Services Acquisition; (8) Supply Chain Protection; and (9) Component Authenticity.[69]

Comments

38. NERC states that a Commission directive requiring the development of a supply chain risk management Reliability Standard: (1) should provide a minimum of two years for Reliability Standard development activities; (2) should clarify that any such Reliability Standard build on existing protections in the CIP Reliability Standards and the practices of responsible entities, and focus primarily on those procedural controls that responsible entities can reasonably be expected to implement during the procurement of products and services associated with bulk electric system operations to manage supply chain risks; and (3) must be flexible to account for differences in the needs and characteristics of responsible entities, the diversity of bulk electric system environments, technologies, risks, and issues related to the limited applicability of mandatory NERC Reliability Standards.[70]

39. While sharing the Commission's concern that supply chain risks pose a threat to bulk electric system reliability, some commenters suggest that the Commission address certain threshold issues before moving forward with the NOPR proposal. IRC notes its

[69] NOPR, 152 FERC ¶ 61,054 at P 65 (citing NIST Special Publication 800-161 at 51).

[70] NERC NOPR Comments at 8-9.

concern that the NOPR proposal is overly broad, which IRC states could hamper industry's ability to address the Commission's concerns.[71] Idaho Power expresses a concern "that tightening purchasing controls too tightly could also pose a risk because there are limited vendors" available to industry.[72] Idaho Power states that any supply chain Reliability Standard "should be laid out in terms of requirements built around controls that are developed by the regulated entity rather than prescriptive requirements like many other CIP standards."[73] ISO-NE supports the development of procedural controls "such as requirements that Registered Entities must transact with organizations that meet certain criteria, use specified procurement language in contracts, and review and validate vendors' security practices."[74] Peak notes that "the number of vendors for certain hardware, software and services may be limited" and, therefore, a supply chain-related Reliability Standard should grant responsible entities the flexibility "to show preference for, but not the obligation to use, vendors who demonstrate sound supply chain security practices."[75]

40. NERC, the Trade Associations, Southern, Gridwise, and other commenters request that, should the Commission find it reasonable to direct NERC to develop a new or

[71] IRC NOPR Comments at 2.

[72] Idaho Power NOPR Comments at 3.

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

[74] ISO-NE NOPR Comments at 2 (citing NERC NOPR Comments at 17-18).

[75] Peak NOPR Comments at 4.

modified Reliability Standard for supply chain management, the Commission adopt certain principles for NERC to follow in the standards development process. As an initial matter, NERC and other commenters state that the Commission should identify the risks that it intends NERC to address.[76] In addition, NERC, SPP RE, and AEP state that the Commission should ensure that any new or modified supply chain-related Reliability Standard carefully considers the risk being addressed against the cost of mitigating that risk.[77]

41. NERC states that the focus of any supply chain risk management Reliability Standard "should be a set of requirements outlining those procedural controls that entities should take, as purchasers of products and services, to design more secure products and modify the security practices of suppliers, vendors, and other parties throughout the supply chain."[78] Similarly, SPP RE notes that, while one responsible entity alone may not have adequate leverage to make a vendor or supplier adopt adequate security practices, "the collective application of the procurement language across a broad collection of Responsible Entities may achieve the intended improvement in security

[76] NERC NOPR Comments at 9-11; Trade Associations NOPR Comments at 26; Gridwise NOPR Comments at 5; AEP NOPR Comments at 8; SPP RE NOPR Comments at 11; EnergySec NOPR Comments at 4.

[77] NERC NOPR Comments at 11-12; SPP RE NOPR Comments at 11; AEP NOPR Comments at 9.

[78] NERC NOPR Comments at 17.

safeguards."[79] Isologic and Resilient Societies recommends limiting the Reliability Standard requirements to a few that are immediately necessary, such as: (1) preventing the installation of cyber related system or grid components which have been reported by ICS-CERT to be provably vulnerable to a supply chain attack, unless the vulnerability has been corrected; (2) removing from operation any system or component reported by ICS-CERT as containing an exploitable vulnerability; and (3) subjecting hardware and software to penetration testing prior to installation on the grid.[80]

42. In post-technical conference comments, while still opposing the NOPR proposal, APPA suggests certain parameters that should govern the development of any supply chain-related Reliability Standard.[81] Specifically, APPA states that a supply chain-related Reliability Standard should be risk-based and "must embody an approach that enables utilities to perform a risk assessment of the hardware and systems that create potential vulnerabilities," similar to the approach taken in Reliability Standard CIP-014-2, Requirement R1 (Physical Security).[82] In addition, APPA states that a supply chain-related Reliability Standard should not require responsible entities to actively manage third-party vendors or their processes since that would risk involving utilities in areas that

[79] SPP RE NOPR Comments at 12.

[80] Isologic and Resilient Societies Joint NOPR Comments at 11.

[81] APPA's post-technical conference comments were submitted jointly with LPPC and TAPS.

[82] APPA Post-Technical Conference Comments at 3-4.

are outside of their core expertise. APPA also argues that "it would be unreasonable for any standard that FERC directs to hold utilities liable for the actions of third-party vendors or suppliers."[83] Finally, APPA states that responsible entities should be able to rely on a credible attestation by a vendor or supplier that it complied with identified supply chain security process. APPA contends that this would be the most efficient way to "establish a standard of care on the suppliers' part."[84]

Discussion

43. We direct that NERC, pursuant to section 215(d)(5) of the FPA, develop a forward-looking, objective-driven new or modified Reliability Standard to require each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations. Our directive is consistent with the NOPR comments advocating flexibility as to what form the Commission's directive should take.

44. We agree with NERC and other commenters that a supply chain risk management Reliability Standard should be flexible and fall within the scope of what is possible using Reliability Standards under FPA section 215. The directive discussed below, we believe, is consistent with both points. In particular, the flexibility inherent in our directive

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

[84] *Id.* at 5.

should account for, among other things, differences in the needs and characteristics of responsible entities and the diversity of BES Cyber System environments, technologies and risks. For example, the new or modified Reliability Standard may allow a responsible entity to meet the security objectives discussed below by having a plan to apply different controls based on the criticality of different assets. And by directing NERC to develop a new or modified Reliability Standard, the Commission affords NERC the option of modifying existing Reliability Standards to satisfy our directive. Finally, we direct NERC to submit the new or modified Reliability Standard within one year of the effective date of this Final Rule.[85]

45. The plan required by the new or modified Reliability Standard developed by NERC should address, at a minimum, the following four specific security objectives in the context of addressing supply chain management risks: (1) software integrity and authenticity; (2) vendor remote access; (3) information system planning; and (4) vendor risk management and procurement controls. Responsible entities should be required to achieve these four objectives but have the flexibility as to how to reach the objective (i.e., the Reliability Standard should set goals (the "what"), while allowing flexibility in how a

[85] We note that the Trade Associations request that the Commission allow "at least one year for discussion, development, and approval by the NERC Board of Trustees." *See* Trade Associations Post-Technical Conference Comments at 22. NERC should submit an informational filing within ninety days of the effective date of this Final Rule with a plan to address the Commission's directive.

responsible entity subject to the Reliability Standard achieves that goal (the "how")).[86] Alternatively, NERC can propose an equally effective and efficient approach to address the issues raised in the objectives identified below. In addition, while in the discussion below we identify four objectives, NERC may address additional supply chain management objectives in the standards development process, as it deems appropriate.

46. The new or modified Reliability Standard should also require a periodic reassessment of the utility's selected controls. Consistent with or similar to the requirement in Reliability Standard CIP-003-6, Requirement R1, the Reliability Standard should require the responsible entity's CIP Senior Manager to review and approve the controls adopted to meet the specific security objectives identified in the Reliability Standard at least every 15 months. This periodic assessment should better ensure that the required plan remains up-to-date, addressing current and emerging supply chain-related concerns and vulnerabilities.

47. Also, consistent with this reliance on an objectives-based approach, and as part of this periodic review and approval, the responsible entity's CIP Senior Manager should consider any guidance issued by NERC, the U.S. Department of Homeland Security (DHS) or other relevant authorities for the planning, procurement, and operation of industrial control systems and supporting information systems equipment since the prior approval, and identify any changes made to address the recent guidance. This periodic

[86] *See* Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 260.

reconsideration will help ensure an ongoing, affirmative process for reviewing and, when appropriate, incorporating such guidance.

First Objective: Software Integrity and Authenticity

48. The new or modified Reliability Standard must address verification of: (1) the identity of the software publisher for all software and patches that are intended for use on BES Cyber Systems; and (2) the integrity of the software and patches before they are installed in the BES Cyber System environment.

49. This objective is intended to reduce the likelihood that an attacker could exploit legitimate vendor patch management processes to deliver compromised software updates or patches to a BES Cyber System. One of the two focused malware campaigns identified by ICS-CERT in 2014 utilized similar tactics, executing what is commonly referred to as a "Watering Hole" attack[87] to exploit affected information systems. Similar tactics appear to have been used in a recently disclosed attack targeting electric sector infrastructure in Japan.[88] These types of attacks might have been prevented had the

[87] "Watering Hole" attacks exploit poor vendor/client patching and updating processes. Attackers generally compromise a vendor of the intended victim and then use the vendor's information system as a jumping off point for their attack. Attackers will often inject malware or replace legitimate files with corrupted files (usually a patch or update) on the vendor's website as part of the attack. The victim then downloads the files without verifying each file's legitimacy believing that it is included in a legitimate patch or update.

[88] *See* Cylance, Operation DustStorm, https://www.cylance.com/hubfs/2015_cylance_website/assets/operation-dust-storm/Op_Dust_Storm_Report.pdf.

affected entities applied adequate integrity and authenticity controls to their patch management processes.

50. As NERC recognizes in its NOPR comments, NIST SP-800-161 "establish[es] instructional reference points for NERC and its stakeholders to leverage in evaluating the appropriate framework for and security controls to include in any mandatory supply chain management Reliability Standard."[89] NIST SP-800-161 includes a number of security controls which, when taken together, reduce the probability of a successful Watering Hole or similar cyberattack in the industrial control system environment and thus could assist in addressing this objective. For example, in the System and Information Integrity (SI) control family, control SI-7 suggests that the integrity of information systems and components should be tested and verified using controls such as digital signatures and obtaining software directly from the developer. In the Configuration Management (CM) control family, control CM-5(3) requires that the information system prevent the installation of firmware or software without verification that the component has been digitally signed to ensure that hardware and software components are genuine and valid. NIST SP-800-161, while not meant to be definitive, provides examples of controls for addressing the Commission's directive regarding this first objective. Other security controls also could meet this objective.

[89] NERC NOPR Comments at 16-17; *see also* Resilient Societies NOPR Comments at 11.

Second Objective: Vendor Remote Access to BES Cyber Systems

51. The new or modified Reliability Standard must address responsible entities' logging and controlling all third-party (i.e., vendor) initiated remote access sessions. This objective covers both user-initiated and machine-to-machine vendor remote access.

52. This objective addresses the threat that vendor credentials could be stolen and used to access a BES Cyber System without the responsible entity's knowledge, as well as the threat that a compromise at a trusted vendor could traverse over an unmonitored connection into a responsible entity's BES Cyber System. The theft of legitimate user credentials appears to have been a critical aspect to the successful execution of the 2015 cyberattack on Ukraine's power grid.[90] In addition, controls adopted under this objective should give responsible entities the ability to rapidly disable remote access sessions in the event of a system breach.

53. DHS noted the importance of controlling vendor remote access in its alert on the Ukrainian cyberattack: "Remote persistent vendor connections should not be allowed into the control network. Remote access should be operator controlled, time limited, and procedurally similar to "lock out, tag out." The same remote access paths for vendor and employee connections can be used; however, double standards should not be allowed."[91]

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[90] *See* E-ISAC, *Analysis of the Cyber Attack on the Ukrainian Power Grid* at 3 (Mar. 18, 2016), http://www.nerc.com/pa/CI/ESISAC/Documents/E-ISAC_SANS_Ukraine_DUC_18Mar2016.pdf.

[91] *See* ICS-CERT Alert, *Cyber-Attack Against Ukrainian Critical Infrastructure*, https://ics-cert.us-cert.gov/alerts/IR-ALERT-H-16-056-01.

54. NIST SP-800-53 and NIST SP-800-161 provide several security controls which, when taken together, reduce the probability that an attacker could use legitimate third-party access to compromise responsible entity information systems. In the Systems and Communications (SC) control family, for example, control SC-7 addressing boundary protection requires that an entity implement appropriate monitoring and control mechanisms and processes at the boundary between the entity and its suppliers, and that provisions for boundary protections should be incorporated into agreements with suppliers. These protections are applied regardless of whether the remote access session is user-initiated or interactive in nature.

55. In the Access Control (AC) control family, control AC-17 requires usage restrictions, configuration/connection requirements, and monitoring and control for remote access sessions, including the entity's ability to expeditiously disconnect or disable remote access. In the Identification and Authentication (IA) control family, control IA-5 requires changing default "authenticators" (e.g., passwords) prior to information system installation. In the System and Information Integrity (SI) control family, control SI-4 addresses monitoring of vulnerabilities resulting from past information and communication technology supply chain compromises, such as malicious code implanted during software development and set to activate after deployment. These sources, while not meant to be definitive, provide examples of controls for addressing the Commission's directive regarding objective two. Other security controls also could meet this objective.

Third Objective: Information System Planning and Procurement

56. The new or modified Reliability Standard must address how a responsible entity will include security considerations as part of its information system planning and system development lifecycle processes. As part of this objective, the new or modified Reliability Standard must address a responsible entity's CIP Senior Manager's (or delegate's) identification and documentation of the risks of proposed information system planning and system development actions. This objective is intended to ensure adequate consideration of these risks, as well as the available options for hardening the responsible entity's information system and minimizing the attack surface.

57. This third objective addresses the risk that responsible entities could unintentionally plan to procure and install unsecure equipment or software within their information systems, or could unintentionally fail to anticipate security issues that may arise due to their network architecture or during technology and vendor transitions. For example, the BlackEnergy malware campaign identified by ICS-CERT and referenced in the NOPR resulted from the remote exploitation of previously unidentified vulnerabilities, which allowed attackers to remotely execute malicious code on remotely accessible devices.[92] According to ICS-CERT, this attack might have been mitigated if affected entities had taken steps during system development and planning to: (1) minimize network exposure for all control system devices/subsystems; (2) ensure that

[92] *See* ICS-CERT Alert, *Ongoing Sophisticated Malware Campaign Compromising ICS (Update E).*

devices were not accessible from the internet; (3) place devices behind firewalls; and (4) utilize secure remote access techniques.[93] The third objective also supports, where appropriate, the need for strategic technology refreshes as recommended by ICS-CERT in response to the 2015 Ukraine cybersecurity incident.[94]

58. NIST SP 800-53 and SP 800-161 provide several controls which, when taken together, reduce the likelihood that an information system will be deployed and/or remain in service with potential vulnerabilities that have not been identified or adequately considered. For example, in the NIST SP 800-53 Systems Acquisition (SA) control family, control SA-3 provides that organizations should: (1) manage information systems using an organizationally-defined system development life cycle that incorporates information security considerations; and (2) integrate the organizational information security risk management process into system development life cycle activities.[95] Similarly, control SA-8 recommends using secure engineering principles during the planning and acquisition phases of future projects such as: (1) developing layered protections; (2) establishing sound security policy, architecture, and controls as the foundation for design; (3) incorporating security requirements into the system

[93] *See* ICS-CERT Advisory, *GE Proficy Vulnerabilities*, https://ics-cert.us-cert.gov/advisories/ICSA-14-023-01.

[94] *See* ICS-CERT Alert, *Cyber-Attack Against Ukrainian Critical Infrastructure*.

[95] NIST Special Publication 800-53, Appendix F (Security Control Catalog) at 157.

development life cycle; and (4) reducing risk to acceptable levels, thus enabling informed risk management decisions.[96] Finally, control SA-22 provides controls to address unsupported system components, recommending the replacement of information and communication technology components when support is no longer available, or the justification and approval of an unsupported system component to meet specific business needs. These sources, while not meant to be definitive, provide examples of controls for addressing the Commission's directive regarding objective three. Other security controls also could meet this objective.

Fourth Objective: Vendor Risk Management and Procurement Controls

59. The new or modified Reliability Standard must address the provision and verification of relevant security concepts in future contracts for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations. Specifically, NERC must address controls for the following topics: (1) vendor security event notification processes; (2) vendor personnel termination notification for employees with access to remote and onsite systems; (3) product/services vulnerability disclosures, such as accounts that are able to bypass authentication or the presence of hardcoded passwords; (4) coordinated incident response activities; and (5) other related aspects of procurement. NERC should also consider provisions to help

[96] *Id.* at 162.

responsible entities obtain necessary information from their vendors to minimize potential disruptions from vendor-related security events.

60. This fourth objective addresses the risk that responsible entities could enter into contracts with vendors who pose significant risks to their information systems, as well as the risk that products procured by a responsible entity fail to meet minimum security criteria. In addition, this objective addresses the risk that a compromised vendor would not provide adequate notice and related incident response to responsible entities with whom that vendor is connected.

61. The Department of Energy (DOE) Cybersecurity Procurement Language for Energy Delivery Systems document outlines security principles and controls for entities to consider when designing and procuring control system products and services (e.g., software, systems, maintenance, and networks), and provides example language that could be incorporated into procurement specifications. The procurement language encourages buyers to incorporate baseline procurement language that ensures the supplier establishes, documents and implements risk management practices for supply chain delivery of hardware, software, and firmware.[97] In addition, NIST SP 800-161 encourages buyers to use the Information and Communications Technology supply chain risk management (ICT SCRM) plans for their respective systems and missions

[97] *See* Energy Sector Control Systems Working Group, *Cybersecurity Procurement Language –Energy Delivery Systems* at 27, http://www.energy.gov/sites/prod/files/2014/04/f15/CybersecProcurementLanguage-EnergyDeliverySystems_040714_fin.pdf.

throughout their acquisition activities.[98] The controls in the ICT SCRM plans can be applied in different life cycle processes.

62. NIST SP 800-161 also provides specific recommendations in control SA-4 pertaining to systems acquisition processes, which are relevant for consideration during the standards development process, including but not limited to: (1) defining requirements that cover regulatory requirements (i.e., telecommunications or IT), technical requirements, chain of custody, transparency and visibility, sharing information on supply chain security incidents throughout the supply chain, rules for disposal or retention of elements such as components, data, or intellectual property, and other relevant requirements; (2) defining requirements for critical elements in the supply chain to demonstrate a capability to remediate emerging vulnerabilities based on open source information and other sources; and (3) defining requirements for the expected life span of the system and ensuring that suppliers can provide insights into their plans for the end-of-life of components. Other relevant provisions can be found in the System and Communications Protection (SC) control family under control SC-18 addressing SCRM guidance for mobile code, which recommends that organizations employ rigorous supply chain protection techniques in the acquisition, development, and use of mobile code to be

[98] *See* NIST Special Publication 800-161 at 51.

deployed in information systems.[99] These sources, while not meant to be definitive, provide examples of controls for addressing the Commission's directive regarding objective four. Other security controls also could meet this objective.

3. Existing CIP Reliability Standards

Comments

63. NERC comments that although the CIP Reliability Standards do not explicitly address supply chain procurement practices, existing requirements mitigate the supply chain risks identified in the NOPR. In particular, NERC states that requirements in Reliability Standards CIP-004-6, CIP-005-5, CIP-006-6, CIP-007-6, CIP-008-5, CIP-009-6, CIP-010-2, and CIP-011-2 "include controls that correspond to controls in NIST SP 800-161."[100]

64. For example, NERC explains that responsible entity compliance with Reliability Standard CIP-004-6, addressing the implementation of cybersecurity awareness programs, may include reinforcement of cybersecurity practices to mitigate supply chain risks. NERC also states that requirements in Reliability Standard CIP-004-6 (addressing personnel risk assessment) and requirements in Reliability Standards CIP-004-6, CIP-

[99] Mobile code is a software program or parts of a program obtained from remote information systems, transmitted across a network, and executed on a local information system without explicit installation or execution by the recipient. NIST Special Publication 800-53, Appendix B (Glossary) at 14. Mobile code technologies include, for example, Java, JavaScript, ActiveX, Postscript, PDF, Shockwave movies, Flash animations, and VBScript. *Id*.

[100] NERC NOPR Comments at 15-16.

005-5, CIP-006-6, CIP-007-6, and CIP-010-2 (addressing electronic and physical access) apply to any outside vendors or contractors.

65. The Trade Associations, Arkansas, G&T Cooperatives, NIPSCO, Luminant, Southern, NextEra, and SCE contend that the existing CIP Reliability Standards, at least partly, address supply chain risks that are within a responsible entity's control.

66. The Trade Associations state that, while the existing CIP Reliability Standards do not contain explicit provisions addressing supply chain management, "transmission owners and operators already have significant responsibilities to perform under various Commission-approved CIP standards that already address supply chain issues."[101] Specifically, the Trade Associations, NIPSCO, and others state that Reliability Standard CIP-010-2 establishes requirements for cyber asset change management that mandate extensive baseline configuration testing and change monitoring, as well as vulnerability assessments, prior to connecting a new cyber asset to a High Impact BES Cyber Asset.[102]

67. The Trade Associations also contend that the CIP Reliability Standards provide adequate vendor remote access protections by mandating: (1) controls that restrict personnel access (physical and electronic) to protected information systems; (2) controls that prevent direct access to applicable systems for interactive remote access sessions

[101] Trade Associations NOPR Comments at 19-20.

[102] Trade Associations NOPR Comments at 20; NIPSCO NOPR Comments at 5; Southern NOPR Comments at 12; Luminant NOPR Comments at 4-5; SCE NOPR Comments at 6.

using routable protocols; (3) the use of encryption for connections extending outside of an electronic security perimeter; (4) the use of two factor authentication when accessing medium and high impact systems; and (5) integration controls which require changing known default accounts and passwords.[103]

68. NIPSCO, Luminant, and G&T Cooperatives point to Reliability Standard CIP-007-6 as an existing Reliability Standard that addresses supply chain risks. Reliability Standard CIP-007-6 requires responsible entities to have processes under which only necessary ports and services should be enabled; security patches should be tracked, evaluated, and installed on applicable BES Cyber Systems; and anti-virus software or other prevention tools should be used to prevent the introduction and propagation of malicious software on all Cyber Assets within an Electronic Security Perimeter.[104]

69. Commenters also identify existing voluntary guidelines that, they contend, augment the existing CIP Reliability Standards to further address any potential risks posed by the supply chain. Southern points to voluntary cybersecurity procurement guidance materials developed by the DHS and the DOE as examples of procurement language that could be used in the course of vendor negotiations. Southern states that the

[103] Trade Associations Post-Technical Conference Comments at 6.

[104] NIPSCO NOPR Comments at 5; Luminant NOPR Comments at 4; G&T Cooperatives NOPR Comments at 8-9.

DHS and DOE guidelines recognize the need for flexibility and allow for multiple contractual approaches.[105]

70. Commenters suggest that the Commission direct NERC to develop cybersecurity procurement guidance documents as opposed to a mandatory Reliability Standard. AEP, NextEra, and Southern state that the Commission could direct NERC to develop guidance documents addressing supply chain risk management based, in part, on the DHS and DOE voluntary cybersecurity procurement guidance materials.[106] Luminant asserts that NERC-developed guidance "would effectively communicate key issues while permitting industry the flexibility to effectively protect their BES Cyber Systems in a way most effective for that entity and at the lowest cost."[107]

Discussion

71. While we recognize that existing CIP Reliability Standards include requirements that address aspects of supply chain management, we determine that existing Reliability Standards do not adequately protect against supply chain risks that are within a responsible entity's control. Specifically, we find that existing CIP Reliability Standards do not provide adequate protection for the four aspects of supply chain risk management that underlie the four objectives for a new or modified Reliability Standard discussed

[105] Southern NOPR Comments at 13.

[106] AEP NOPR Comments at 7-8; NextEra NOPR Comments at 4-5; Southern NOPR Comments at 12-13.

[107] Luminant NOPR Comments at 5.

above.[108] Moreover, a fundamental premise of cyber security is "defense in depth," and addressing issues in the supply chain (to the extent a utility reasonably can) is an important component of a strong, multi-layered defense.

Software Integrity and Authenticity

72. With regard to software integrity and authenticity, we agree with commenters who state that the existing CIP Reliability Standards contain requirements for responsible entities to implement a patch management process for tracking, evaluating, and installing cybersecurity patches and to implement processes to detect, prevent, and mitigate the threat of malicious code. These provisions, however, do not require responsible entities to verify the identity of the software publisher for all software and patches that are intended for use on their BES Cyber Systems or to verify the integrity of the software and patches before they are installed in the BES Cyber System environment.[109] As discussed above, the CIP Reliability Standards should address compromised software or patches that a responsible entity receives from a vendor, in order to protect the bulk electric system from Watering-Hole or similar cyberattacks. These concerns are not addressed by existing CIP Reliability Standards.

[108] Since the directive to NERC to develop a new or modified Reliability Standard is limited to the four objectives discussed above, we limit our analysis of the existing CIP Reliability Standards to requirements that relate to those objectives.

[109] *See* Trade Associations NOPR Comments at 38 (indicating that integrity checking mechanisms used to verify software, firmware, and information integrity found in the NIST SP-800-161 System and Information Integrity (SI) control family are not addressed in the CIP version 5 Reliability Standards).

73. Mandatory controls in the existing CIP Reliability Standards referenced by commenters do not provide sufficient protection against attacks that compromise software and software patch integrity and authenticity. For example, while Reliability Standard CIP-007-6, Requirement R2 requires responsible entities to enforce a patch management process for tracking, evaluating, and installing cyber security patches for applicable systems, including evaluating security patches for applicability, the requirement does not address mechanisms to acquire the patch file from a vendor in a secure manner and methods to validate the integrity of a patch file before installation.

74. With respect to mandatory configuration controls, Reliability Standard CIP-010-2, Requirement R1 requires responsible entities to authorize and document all changes to baseline configurations and, where technically feasible, test patches in a test environment before installing. However, NERC's technical guidance document for CIP-010-2, Requirement R1, Part 1.2 does not require the authorizer to first verify the authenticity of a patch. Similarly, the testing of patches in a test environment under Requirement R1.5 would likely provide insufficient protection as many malware variants are programmed to execute only after the system is rebooted several times. Regarding patch source monitoring, the guidelines and technical basis section for Reliability Standard CIP-007-6 suggests that responsible entities should obtain security patches from original sources, where possible, and indicates that patches should be approved or certified by another

source before being assessed and applied.[110] The Reliability Standard, however, does not require the use of these techniques. Implementing controls that verify integrity and authenticity of software and its publishers may help mitigate security gaps listed above.

75. In sum, the current CIP Reliability Standards do contain certain controls addressing the risks posed by malware, as stated by commenters. Verifying software integrity and authenticity, however, is a reasonable and appropriate complement to these controls, is not required by the current Standards, and is supported by the principle of defense-in-depth. In fact, this verification can be viewed as the first line of defense against malware-infected software.

Vendor Remote Access to BES Cyber Systems

76. On the subject of vendor remote access, which includes vendor user-initiated Interactive Remote Access and vendor machine-to-machine remote access, existing CIP Reliability Standards contain system access requirements, including a requirement for security event monitoring. However, the CIP Reliability Standards do not require remote access session logging for machine-to-machine remote access, nor do they address the ability to monitor or close unsafe remote connections for both vendor Interactive Remote

[110] Reliability Standard CIP-007-6 (Cyber Security – Systems Security Management), Guidelines and Technical Basis at 42-43.

Access and vendor machine-to-machine remote access.[111] The CIP Reliability Standards should address enhanced session logging requirements for vendor remote access in order to improve visibility of activity on BES Cyber Systems and give responsible entities the ability to rapidly disable remote access sessions in the event of a system breach.

77. The existing requirements referenced by NERC, the Trade Associations, and other commenters do not adequately address access restrictions for vendors. For example, while Reliability Standard CIP-004-6, Requirements R4 and R5 provide controls that must be applied to vendors such as restricting access to individuals "based on need," these Requirements do not include post-authorization logging or control of remote access. The existing CIP Reliability Standards do not require a responsible entity to monitor data traffic that traverses remote communication to their BES Cyber Systems. The absence of post-authorization monitoring and logging presents an opportunity for unmonitored malicious or otherwise inappropriate remote communication to or from a BES Cyber System. The inability of a responsible entity to rapidly terminate a connection may allow malicious or otherwise inappropriate communication to propagate, contributing to a degradation of a BES Cyber Asset's function. Enhanced visibility into remote communications and the ability to rapidly terminate a remote communication could mitigate such a vulnerability.

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[111] *See* Trade Association NOPR Comments at 43 (indicating that mechanisms for monitoring for unauthorized personnel, connections, devices, and software found in the NIST SP-800-161 System and Information Integrity (SI) control family are not addressed in the CIP version 5 Reliability Standards).

78. Reliability Standard CIP-005-5, Requirement R1 provides controls for vendor machine-to-machine and vendor user-initiated Interactive Remote Access sessions by restricting all inbound and outbound communications through an identified Electronic Access Point for bi-directional routable protocol connections. Reliability Standard CIP-005-5, Requirement R2 provides controls for vendor interactive remote access sessions by requiring the use of encryption and requiring multi-factor authentication. However, the provisions of Reliability Standard CIP-005-5, Requirement R2 addressing interactive remote access management do not apply to vendor machine-to-machine remote access. The Reliability Standard CIP-005-5, Requirement R2 controls addressing interactive remote access management only apply to remote connections that are user-initiated (i.e., initiated by a person). Machine-to-machine connections are not user-initiated and, therefore, are not subject to the requirements of Reliability Standard CIP-005-5, Requirement R2. When the interactive remote access management controls of Reliability Standard CIP-005-5, Requirement R2 do not apply, a machine-to-machine remote communication may access a BES Cyber System without any access credentials, over an unencrypted channel, and without going through an Intermediate System.

79. For both Interactive Remote Access and machine-to-machine remote access, Reliability Standard CIP-007-6, Requirement R3 requires monitoring for malicious code and Requirement R4 requires logging of successful and unsuccessful login attempts, as well as logging detected malicious code. However, Reliability Standard CIP-007-6 does not address the risks posed by inappropriate activity that could occur during a remote communication. The lack of a requirement addressing the detection of inappropriate

activity represents a risk because the responsible entity may not be aware if an authorized user is performing inappropriate activity on a BES Cyber Asset via a remote connection. This risk is higher for machine-to-machine communication due to the lack of authentication and encryption requirements in the existing CIP Reliability Standards, lowering the threshold for a malicious actor to execute a man-in-the-middle attack to gain access to a BES Cyber System and conduct inappropriate activity such as reconnaissance or code modification.

80. Therefore, we recognize that the current CIP Reliability Standards do contain certain controls addressing the risks posed by vendor remote access, as noted by commenters. However, the current CIP Reliability Standards do not require monitoring remote access sessions or closing unsafe remote connections for either vendor Interactive Remote Access and vendor machine-to-machine remote access. Accordingly, we determine that vendor remote access is not adequately addressed in the approved CIP Reliability Standards and, therefore, is an objective that must be addressed in the supply chain management plans directed in this final rule.

Information System Planning and Procurement

81. The existing CIP Reliability Standards do not address information system planning. Recent cybersecurity incidents[112] have made it apparent that overall system

[112] *See* E-ISAC, *Analysis of the Cyber Attack on the Ukrainian Power Grid* at 3 (March 18, 2016); *see also* Dell, *Dell Security Annual Threat Report* (2015) at 7, https://software.dell.com/docs/2015-dell-security-annual-threat-report-white-paper-15657.pdf; Olcott Technical Conference Comments at 2.

planning is as important to overall BES Cyber System security and reliability as any other component of security architecture. In general, the CIP Reliability Standards do not provide a framework for maintaining ongoing awareness of information security, vulnerabilities, and threats to support organization risk management decisions;[113] nor do they address the concept of integrating continuous improvement of organizational security posture with supply chain risk management as recommended by NIST SP 800-161.[114] Based on the threats evidenced by recent cybersecurity incidents, the absence of security considerations in system lifecycle processes constitutes a gap in the CIP Reliability Standards that could contribute to pervasive and systemic vulnerabilities that threaten bulk electric system reliability.

82. The existing CIP Reliability Standards also do not provide for procurement controls for industrial control system hardware, software, and computing and networking services. As discussed above, procurement controls are intended to address the threat that responsible entities could enter into contracts with vendors who pose significant risks to their information systems or procure products that fail to meet minimum security criteria, as well as the risk that a compromised vendor would not provide adequate notice and related incident response to responsible entities with whom that vendor is connected.

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[113] *See* NIST Special Publication 800-137, *Information Security Continuous Monitoring (ISCM) for Federal Information Systems and Organizations* at vi, http://nvlpubs.nist.gov/nistpubs/Legacy/SP/nistspecialpublication800-137.pdf.

[114] NIST Special Publication 800-161 at 46.

83. With regard to commenters' suggestion that the Commission direct NERC to develop cybersecurity procurement guidance documents as opposed to a mandatory Reliability Standard, we agree that the voluntary efforts identified by commenters could provide guidance or otherwise inform NERC's standard development process. We conclude, however, that relying on voluntary guidelines to address the supply chain risks described above is not sufficient to fulfill the Commission's responsibilities under FPA section 215.

4. Vendor Risk Management and Procurement Controls

Comments

84. NERC, G&T Cooperatives, Arkansas and others state that responsible entities have limited influence over vendors and contractors, and, therefore, a limited ability to affect the supply chain for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations.[115] NERC contends that any supply chain management Reliability Standard "must balance the reliability need to implement supply chain management security controls with entities' business need to obtain products and services at a reasonable cost."[116] NERC maintains that responsible entities lack bargaining power to persuade vendors or suppliers to implement cybersecurity controls without significantly increasing the cost of their

[115] NERC NOPR Comments at 11-12; G&T Cooperatives NOPR Comments at 9; Arkansas NOPR Comments at 5.

[116] NERC NOPR Comments at 11-12.

products or services. NERC points to NIST SP 800-161 to highlight that implementing supply chain security management controls "will require financial and human resources, not just from the [acquirer] directly but also potentially from their system integrators, suppliers, and external service providers that would also result in increased cost to the acquirer."[117]

85. G&T Cooperatives contend that they "have minimal control over their suppliers and are not able to identify all potential vulnerabilities associated with each and every supplier and their products/parts."[118] G&T Cooperatives and Arkansas maintain that responsible entities do not have the ability to force a vendor to address all potential vulnerabilities. G&T Cooperatives assert that even if a contract between a responsible entity and a supplier "could include" language requiring the supplier to implement security controls, "it is not feasible for contractual terms … to address all potential vulnerabilities related to supply chain management."[119]

86. NERC, Trade Associations, G&T Cooperatives and Arkansas also raise a concern that the Commission's proposal could place compliance risk on responsible entities for actions beyond their control and, ultimately, incent responsible entities to avoid upgrades

[117] *Id.* (citing NIST Special Publication 800-161 at 3).

[118] G&T Cooperatives NOPR Comments at 9.

[119] *Id.* at 9.

that could trigger such compliance risk.[120] NERC states that any supply chain management Reliability Standard should be drafted so that it "creates affirmative obligations to implement supply chain management security controls without holding entities strictly liable for any failure of those controls to eliminate all supply chain threats and vulnerabilities."[121] NERC explains that if a supply chain management Reliability Standard is not reasonably scoped to avoid unreasonable compliance risk, it could create a disincentive for responsible entities to purchase and install new technologies and equipment.

87. G&T Cooperatives state that "placing the compliance risk of vendor and supplier security vulnerability on Responsible Entities could incent Responsible Entities to avoid upgrades to their industrial control system hardware, software, and other services." G&T Cooperatives explain that there are three primary incentives for a responsible entity to avoid upgrades if faced with compliance risks: (1) new regulations would result in additional costs for vendors and suppliers that would be passed on to the end-user; (2) since security patches are not issued by vendors for unsupported hardware and software, there is less security patch management responsibility for the responsible entity; and (3)

[120] NERC NOPR Comments at 13; Trade Associations NOPR Comments at 24-25; G&T Cooperatives NOPR Comments at 9-10; Arkansas NOPR Comments at 6.

[121] NERC NOPR Comments at 13.

avoiding new hardware and software reduces the risk of introducing undetected security threats.[122]

Discussion

88. Our directive to NERC to develop a new or modified Reliability Standard that addresses the objectives outlined above balances the supply chain risks facing the bulk electric system against any potential challenges raised by vendor relationships. We believe that the concerns raised in comments with respect to responsible entities' relationships with vendors in relation to supply chain risks are valid. Our directive is informed by this concern and reflects a reasonable balance between the risks facing bulk electric system reliability from the supply chain and concerns over vendor relationships. The directive strikes this balance by addressing supply chain risks that are within responsible entities' control, and we do not expect a new or modified supply chain Reliability Standard to impose obligations directly on vendors. Moreover, entities will not be responsible for vendor errors beyond the scope of the controls implemented to comply with the Reliability Standards.

89. With respect to concerns that the Commission's proposal could place compliance risk on responsible entities for actions beyond their control, which some commenters argue would prompt responsible entities to avoid upgrades that could trigger such compliance risk, we reiterate that the intent of the directive is to address supply chain

[122] G&T Cooperatives NOPR Comments at 9.

risks that are within the responsible entities' control. As part of NERC's standard development process, we expect NERC to establish provisions addressing compliance obligations in a manner that avoids shifting liability from a vendor for its mistakes to a responsible entity. Finally, we view the argument that a new or modified Reliability Standard will result in a substantial increase in costs to be speculative because, beyond requiring NERC to address the four objectives discussed above, or some equally effective and efficient alternatives, our directive does not require NERC to develop a Reliability Standard that mandates any particular controls or actions.

III. Information Collection Statement

90. The Paperwork Reduction Act (PRA)[123] requires each federal agency to seek and obtain Office of Management and Budget (OMB) approval before undertaking a collection of information directed to ten or more persons or contained in a rule of general applicability. OMB regulations[124] require approval of certain information collection requirements imposed by agency rules. Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of an agency rule will not be penalized for failing to respond to the collection of information unless the collection of information displays a valid OMB control number.

[123] 44 U.S.C. 3507(d).

[124] 5 CFR 1320.

91. The Commission will submit the information collection requirements to OMB for its review and approval. The Commission solicits public comments on its need for this information, whether the information will have practical utility, the accuracy of burden and cost estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

92. The information collection requirements in this Final Rule in Docket No. RM15-14-002 for NERC to develop a new or to modify a Reliability Standard for supply chain risk management, should be part of FERC-725 (Certification of Electric Reliability Organization; Procedures for Electric Reliability Standards (OMB Control No. 1902-0225)). However, there is an unrelated item which is currently pending OMB review under FERC-725, and only one item per OMB Control No. can be pending OMB review at a time. Therefore, the requirements in this Final Rule in RM15-14-002 are being submitted under a new temporary or interim collection number FERC-725(1A) to ensure timely submittal to OMB. In the long-term, Commission staff plans to administratively move the requirements and associated burden of FERC-725(1A) to FERC-725.

93. Burden Estimate and Information Collection Costs: The requirements for the ERO to develop Reliability Standards and to provide data to the Commission are included in the existing FERC-725. FERC-725 includes information used by the Commission to implement the statutory provisions of section 215 of the FPA. FERC-725 includes the burden, reporting and recordkeeping requirements associated with: (a) Self-Assessment and ERO Application, (b) Reliability Assessments, (c) Reliability Standards

Development, (d) Reliability Compliance, (e) Stakeholder Survey, and (f) Other Reporting. In addition, the Final Rule will not result in a substantive increase in burden because this requirement to develop standards is covered under FERC-725. However because FERC is using the temporary information collection number, FERC-725(1A), FERC will use "placeholder" estimates of 1 response and 1 burden hour for the burden calculation.

IV. Regulatory Flexibility Act Analysis

94. The Regulatory Flexibility Act of 1980 (RFA)[125] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The Small Business Administration (SBA) revised its size standard (effective January 22, 2014) for electric utilities from a standard based on megawatt hours to a standard based on the number of employees, including affiliates.[126] The entities subject to the Reliability Standards developed by the North American Electric Reliability Corporation (NERC) include users, owners, and operators of the Bulk-Power System, which serves more than 334 million people. In addition, NERC's current responsibilities include the development of Reliability Standards. Accordingly, the Commission certifies that the requirements in this Final Rule will not have a

[125] 5 U.S.C. 601-612.

[126] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77,343 (Dec. 23, 2013).

significant economic impact on a substantial number of small entities, and no regulatory flexibility analysis is required.

V. Environmental Analysis

95. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[127] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[128] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

VI. Effective Date and Congressional Notification

96. This Final Rule is effective **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. This Final Rule is being submitted to the Senate, House, and Government Accountability Office.

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

[128] 18 CFR 380.4(a)(2)(ii).

VII. Document Availability

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

98. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.

99. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or e-mail at ferconlinesupport@ferc.gov, or the Public Reference

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

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Note: the following Appendix will not appear in the *Code of Federal Regulations*.

Appendix
Commenters

Abbreviation	Commenter
AEP	American Electric Power Service Corporation
ACS	Applied Control Solutions, LLC
APS	Arizona Public Service Company
Arkansas	Arkansas Electric Cooperative
BPA	Bonneville Power Administration
CEA	Canadian Electricity Association
Consumers Energy	Consumers Energy Company
CyberArk	CyberArk
EnergySec	Energy Sector Security Consortium, Inc.
Ericsson	Ericsson
Resilient Societies	Foundation for Resilient Societies
G&T Cooperatives	Associated Electric Cooperative, Inc., Basin Electric Power Cooperative, and Tri-State Generation and Transmission Association, Inc.
Gridwise	Gridwise Alliance
Idaho Power	Idaho Power Company
Indegy	Indegy
IESO	Independent Electricity System Operator
IRC	ISO/RTO Council
ISO New England	ISO New England Inc.
ITC	ITC Companies
Isologic	Isologic, LLC
KCP&L	Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company
Luminant	Luminant Generation Company, LLC
NEMA	National Electrical Manufacturers Association
NERC	North American Electric Reliability Corporation
NextEra	NextEra Energy, Inc.
NIPSCO	Northern Indiana Public Service Co.
NWPPA	Northwest Public Power Association
Peak	Peak Reliability
PNM	PNM Resources
Reclamation	Department of Interior Bureau of Reclamation
SIA	Security Industry Association
SCE	Southern California Edison Company

Southern	Southern Company Services
SPP RE	Southwest Power Pool Regional Entity
SWP	California Department of Water Resources State Water Project
TVA	Tennessee Valley Authority
Trade Associations	Edison Electric Institute, American Public Power Association, National Rural Electric Cooperative Association, Electric Power Supply Association, Transmission Access Policy Study Group, and Large Public Power Council
UTC	Utilities Telecom Council
Waterfall	Waterfall Security Solutions, Ltd.
Wisconsin	Wisconsin Electric Power Company

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Revised Critical Infrastructure Protection Reliability Standards — Docket No. RM15-14-002

(Issued July 21, 2016)

LaFLEUR, Commissioner *dissenting*:

In today's order, the Commission elects to proceed directly to a Final Rule and require the development of a new reliability standard on supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations. I fully support the Commission's continued attention to the threat of inadequate supply chain risk management procedures, which pose a very real threat to grid reliability.

However, in my view, the importance and complexity of this issue should guide the Commission to proceed cautiously and thoughtfully in directing the development of a reliability standard to address these threats. I am concerned that the Commission has not adequately considered or vetted the Final Rule, which could hamper the development and implementation of an effective, auditable, and enforceable standard. I believe that the more prudent course of action would be to issue today's Final Rule as a Supplemental Notice of Proposed Rulemaking (Supplemental NOPR), which would provide NERC, industry, and stakeholders the opportunity to comment on the Commission's proposed directives. Accordingly, and as discussed below, I dissent from today's order.[1]

I. The Commission's Decision to Proceed Directly to Final Rule is Flawed and Could Delay Protection of the Grid Against Supply Chain Risks

Last July, as part of its NOPR addressing revisions to its cybersecurity critical infrastructure protection (CIP) standards, the Commission raised for the first time the prospect of directing the development of a standard to address risks posed by lack of controls for supply chain management.[2] The Commission indicated that new threats

[1] I do agree with one holding in the order: that the Commission has authority under section 215 of the Federal Power Act to promulgate a standard on this issue.

[2] *Revised Critical Infrastructure Protection Reliability Standards*, Notice of Proposed Rulemaking, 80 Fed. Reg. 43,354 (July 22, 2015), 152 FERC ¶ 61,054 (2015). I will refer to the section of that order addressing supply chain issues as the "Supply Chain NOPR," and the remainder of the order as the "CIP NOPR."

might warrant directing NERC to develop a standard to address those risks. While the Commission noted a variety of considerations that might shape the standard, including, among others, jurisdictional limits and the individualized nature of companies' supply chain management procedures, the Commission notably did not propose a specific standard for comment. Instead, the Commission sought comment on (1) the general proposal to require a standard, (2) the anticipated features of, and requirements that should be included in, such a standard, and (3) a reasonable timeframe for development of a standard.[3]

The record developed in comments responding to the Supply Chain NOPR and through the January 28, 2016 technical conference reflects a wide diversity of views regarding the need for, and possible content of, a reliability standard addressing supply chain management. Notwithstanding these diverse views, there was broad consensus on one point: that effectively addressing cybersecurity threats in supply chain management is tremendously complicated, due to a host of jurisdictional, technical, economic, and business relationship issues. Indeed, in the Supply Chain NOPR, the Commission recognized "that developing a supply chain management standard would likely be a significant undertaking and require extensive engagement with stakeholders to define the scope, content, and timing of the standard."[4]

Yet, the Commission is proceeding straight to a Final Rule without in my view engaging in sufficient outreach regarding, or adequately vetting, the contents of the Final Rule. As to those contents, it is worth noting that the four objectives that will define the scope and content of the standard were not identified in the Supply Chain NOPR. Therefore, even though the Final Rule reflects feedback received on the Supply Chain NOPR, and is not obviously inconsistent with the Supply Chain NOPR, no party has yet had an opportunity to comment on those objectives or consider how they could be translated into an effective and enforceable standard.[5] This is a consequence of: (1) the lack of outreach on supply chain threats prior to issuing the Supply Chain NOPR; (2) the lack of detail in the Supply Chain NOPR regarding what a standard might look like; and (3) the decision today to proceed straight to a Final Rule rather than provide additional opportunities for public feedback.

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[3] *Id.* P 66.

[4] *Id.*

[5] To be clear, I am less concerned about whether the Final Rule satisfies minimal notice requirements than whether the Final Rule represents reasoned decision making by the Commission.

A. The Commission and the Public's Consideration of Supply Chain Risks Would Benefit from Additional Stakeholder Engagement

First, I believe that meaningful stakeholder input on the content of any proposed rule is essential to the Commission's deliberative process. This is especially important in our reliability work, as any standard developed by NERC must be approved by stakeholder consensus before it may be filed at the Commission. I do not believe that the record developed to date establishes that the Final Rule will lead to an appropriate solution to address supply chain risks. I note that much of the feedback we received in response to the Supply Chain NOPR was not focused on the merits of particular approaches to address supply chain threats. Yet, in this order, the Commission directs the development of a standard based on objectives not reflected in the Supply Chain NOPR, depriving the public of the ability to comment, and the Commission of the benefit of that public comment.

In retrospect, given both the preliminary nature of the consideration of the issue and the lack of a concrete idea regarding what a proposed standard would look like, I believe that the Supply Chain NOPR was, in substance, a *de facto* Notice of Inquiry and should have been issued as such, rather than as a subsection of the broader CIP NOPR on changes to the CIP standards. For example, it is instructive to compare the Supply Chain NOPR with two other documents: (1) the Notice of Inquiry being issued today on cybersecurity issues arising from the recent incident in Ukraine,[6] and (2) the NOPR concerning the proposed development of a reliability standard to address geomagnetic disturbances.[7] The level of detail and consideration of the issues presented in the Supply Chain NOPR are much more consistent with that in a Notice of Inquiry than a traditional NOPR. As a result, I am concerned that the Commission, by styling its prior action as a NOPR, has skipped a critical step in the rulemaking process: the opportunity for public comment on its directive to develop a standard and the objectives that will frame the design and development of that standard. As explained below, I believe this procedural decision actually makes it less likely that an effective, auditable, and enforceable standard will be implemented on a reasonable schedule, particularly given the acknowledged complexity of this issue.[8]

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[6] *Cyber Systems in Control Centers*, Notice of Inquiry, Docket No. RM16-18-000.

[7] *Reliability Standards for Geomagnetic Disturbances*, Notice of Proposed Rulemaking, 77 FR 64,935 (Oct. 24, 2012), 141 FERC 61,045 (2012).

[8] I believe that *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014) (Physical Security Directive Order), which is cited in the Final Rule as support for today's action, is primarily relevant to demonstrate a different point than the order indicates. The Physical Security Directive Order followed focused outreach with

(continued…)

B. The Lack of Adequate Stakeholder Engagement Will Have Negative Consequences for the Standards Development Process

I am also concerned about the consequences for the standards development process of the Commission's decision to proceed straight to a Final Rule. In particular, I am concerned that the combination of insufficient process and discussion to develop the record and inadequate time for standards development (since the Commission substantially truncated NERC's suggested timeline)[9] will handicap NERC's ability to develop an effective and enforceable proposed standard for the Commission to consider. As noted above, NERC, industry, and other stakeholders will have no meaningful opportunity before initiating their work to provide feedback on the contents of the rule, to seek clarification from the Commission, or to propose revisions to the rule. Yet, this type of feedback is a critical component of the rulemaking process, to ensure that the entities tasked with implementing the Commission's directive have been heard and understand what they are supposed to do. I believe that the Commission is essentially giving the standards development team a homework assignment without adequately explaining what it expects them to hand in.

NERC and other stakeholders to discuss how a physical security standard could be designed and implemented within the parameters of section 215 of the Federal Power Act. As a result of that outreach, the directives in the Physical Security Directive Order were clear, targeted, and reflected shared priorities between the Commission and NERC. Physical Security Directive Order, 146 FERC ¶ 61,166 at PP 6-9. Consequently, NERC was able to develop and file a physical security standard with the Commission in less than three months, and the Commission ultimately approved that standard in November 2014, only roughly eight months after directing its development. *Physical Security Reliability Standard*, 149 FERC ¶ 61,140 (2014). In my view, this example demonstrates how essential outreach is to the timely and effective development of NERC standards.

[9] In its comments responding to the Supply Chain NOPR, NERC requested that, if the Commission decides to direct the development of a standard, the Commission provide *a minimum* of two years for the standards development process. However, the Commission disregards that request and directs NERC to develop a standard in just one year, apparently based solely on the Trade Associations' request that the Commission allow *at least* one year for the standards development process. I believe this timeline is inconsistent with the Commission's own recognition of the complexity of this issue, and, as discussed herein, likely to delay rather than expedite the implementation of an effective, auditable, and enforceable standard.

I do not believe that the Final Rule's flexibility is a justification for proceeding straight to a Final Rule. Indeed, given the inadequate process to date, I fear that the flexibility is in fact a lack of guidance and will therefore be a double-edged sword. The Commission is issuing a general directive in the Final Rule, in the hope that the standards team will do what the Commission clearly could not do: translate general supply chain concerns into a clear, auditable, and enforceable standard within the framework of section 215 of the Federal Power Act. While the Commission need not be prescriptive in its standards directives, the Commission's order assumes that the standards development team will be able to take the "objectives" of the Final Rule and translate them into a standard that the Commission will ultimately find acceptable. I believe that issuing a Supplemental NOPR would benefit the standards development process by enabling additional discussion and feedback regarding the design of a workable standard.

C. By Failing to Engage in Adequate Stakeholder Outreach Before Directing Development of a Standard, the Commission Increases the Likelihood that Implementation of a Standard Will be Delayed

A compressed and possibly compromised standards development process also has real consequences for the Commission's consideration of that proposed standard, whenever it is filed for our review. Unlike our authority under section 206 of the FPA, the Commission lacks authority under section 215 to directly modify a flawed reliability standard. Instead, to correct any flaws, the statute requires that we remand the standard to NERC and the standards development process.[10] Thus, notwithstanding the majority's desire to quickly proceed to Final Rule, the statutory construct constrains our ability to timely address a flawed standard, which could actually delay implementation of the protections the Commission seeks to put in place.

Given the realities of the standards development and approval process, we are likely years away from a supply chain standard being implemented, even under the aggressive schedule contemplated in the order. I believe that the Commission should endeavor to provide as much advance guidance as possible before mandating the development of a standard, to increase the likelihood that NERC develops a standard that will be satisfactory to the Commission and reduce the need for a remand. I worry that the limited process that preceded the Final Rule and the expedited timetable will make it extremely difficult for NERC to file a standard that the Commission can cleanly approve. Had the Commission committed itself to conducting adequate outreach, I believe we could have mitigated the likelihood of that outcome, and more effectively and promptly addressed the supply chain threat in the long term. "Delaying" action for a few months thus would, in the long run, lead to prompter and stronger protection for the grid.

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[10] 18 U.S.C. § 824o(d)(4).

II. Conclusion

The choice the Commission faces today on supply chain risk management is not between action and inaction. Rather, given the importance of this issue, I believe that more considered action and a more developed Commission order, even if delayed by a few months, is better than a quick decision to "do something." Ultimately, an effective, auditable, and enforceable standard on supply chain management will require thoughtful consideration of the complex challenges of addressing cybersecurity threats posed through the supply chain within the structure of the FERC/NERC reliability process. In my view, the Commission gains very little and does not meaningfully advance the security of the grid by proceeding straight to a Final Rule, rather than taking the time to build a record to support a workable standard.

Accordingly, I respectfully dissent.

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Cheryl A. LaFleur
Commissioner

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

July 14, 2016

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. No. 94-409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING:	FEDERAL ENERGY REGULATORY COMMISSION
DATE AND TIME:	July 21, 2016 10:00 A.M.
PLACE:	Room 2C 888 First Street, N.E. Washington, D.C. 20426
STATUS:	OPEN
MATTERS TO BE CONSIDERED:	Agenda * NOTE - Items listed on the agenda may be deleted without further notice.
CONTACT PERSON FOR MORE INFORMATION:	Kimberly D. Bose Secretary Telephone (202) 502-8400 For a recorded message listing items struck from or added to the meeting, call (202) 502-8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's website at http://www.ferc.gov using the eLibrary link, or may be examined in the Commission's Public Reference Room.

1029TH - MEETING

REGULAR MEETING

July 21, 2016

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD16-1-000	Agency Administrative Matters
A-2	AD16-7-000	Customer Matters, Reliability, Security and Market Operations
A-3	AD16-22-000	Briefing on Revised Memorandum of Understanding Between FERC and the U.S. Army Corps for Non-Federal Hydropower Development at the Corps' Facilities
		ELECTRIC
E-1	ER12-959-007	Southwest Power Pool, Inc.
E-2	ER16-791-000	Southwest Power Pool, Inc.
E-3	EL16-91-000	Southwest Power Pool, Inc.
E-4	EL14-12-001	Association of Businesses Advocating Tariff Equity Coalition of MISO Transmission Customers Illinois Industrial Energy Consumers Indiana Industrial Energy Consumers, Inc. Minnesota Large Industrial Group Wisconsin Industrial Energy Group v. Midcontinent Independent System Operator, Inc. ALLETE, Inc. Ameren Illinois Company Ameren Missouri Ameren Transmission Company of Illinois American Transmission Company LLC Cleco Power LLC Duke Energy Business Services, LLC Entergy Arkansas, Inc. Entergy Gulf States Louisiana, LLC Entergy Louisiana, LLC Entergy Mississippi, Inc. Entergy New Orleans, Inc. Entergy Texas, Inc.

		Indianapolis Power & Light Company International Transmission Company ITC Midwest LLC Michigan Electric Transmission Company, LLC MidAmerican Energy Company Montana-Dakota Utilities Co. Northern Indiana Public Service Company Northern States Power Company-Minnesota Northern States Power Company-Wisconsin Otter Tail Power Company Southern Indiana Gas & Electric Company
E-5	EL15-45-001	Arkansas Electric Cooperative Corporation Mississippi Delta Energy Agency Clarksdale Public Utilities Commission Public Service Commission of Yazoo City Hoosier Energy Rural Electric Cooperative, Inc. v. ALLETE, Inc. Ameren Illinois Company Ameren Missouri Ameren Transmission Company of Illinois American Transmission Company LLC Cleco Power LLC Duke Energy Business Services, LLC Entergy Arkansas, Inc. Entergy Gulf States Louisiana, LLC Entergy Louisiana, LLC Entergy Mississippi, Inc. Entergy New Orleans, Inc. Entergy Texas, Inc. Indianapolis Power & Light Company International Transmission Company ITC Midwest LLC Michigan Electric Transmission Company, LLC MidAmerican Energy Company Montana-Dakota Utilities Co. Northern Indiana Public Service Company Northern States Power Company-Minnesota Northern States Power Company-Wisconsin Otter Tail Power Company Southern Indiana Gas & Electric Company
	EL16-99-000	Midcontinent Independent System Operator, Inc.
E-6	OMITTED	
E-7	RM16-17-000	Data Collection for Analytics and Surveillance and Market-Based Rate Purposes
E-8	RM15-14-002	Revised Critical Infrastructure Protection Reliability Standards
E-9	RM15-14-001	Revised Critical Infrastructure Protection Reliability Standards
E-10	RM16-18-000	Cyber Systems in Control Centers

E-11	RM16-8-000	Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities
E-12	RM05-5-025	Standards for Business Practices and Communication Protocols for Public Utilities
E-13	RM15-23-000	Collection of Connected Entity Data from Regional Transmission Organizations and Independent System Operators
E-14	RM16-3-000	Ownership Information in Market-Based Rate Filings
E-15	ER16-1774-000	Southwest Power Pool, Inc.
E-16	ER16-13-002	Southwest Power Pool, Inc.
E-17	ER12-678-006	Midwest Independent Transmission System Operator, Inc.
E-18	ER12-678-004 EL14-58-001	Midwest Independent Transmission System Operator, Inc.
E-19	OMITTED	
E-20	EL16-69-000 QF16-362-001 QF16-363-001 QF16-364-001 QF16-365-001 QF16-366-001 QF16-367-001 QF16-368-001 QF16-369-001 QF16-370-001 QF16-371-001 QF16-372-001 QF16-373-001 QF16-374-001 QF16-375-001 QF16-376-001 QF16-377-001 QF16-378-001 QF16-379-001 QF16-380-001 QF16-381-001 QF16-382-001 QF16-383-001 QF16-384-001 QF16-385-001 QF16-386-001 QF16-387-001	Windham Solar LLC and Allco Finance Limited
E-21	OMITTED	

E-22	OMITTED	
E-23	QM16-1-000	Nebraska Public Power District

HYDRO

H-1	P-13458-003	BOST1 Hydroelectric LLC

CERTIFICATES

C-1	CP15-498-000	Eastern Shore Natural Gas Company
C-2	CP15-18-000 CP15-18-001	Eastern Shore Natural Gas Company

Kimberly D. Bose,
Secretary.

A free webcast of this event is available through www.ferc.gov. Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit www.CapitolConnection.org or contact Danelle Springer or David Reininger at 703-993-3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Unavailability of the Transmission Stability Limits Calculation Application

Primary Interest Groups
Reliability Coordinators (RCs)
Balancing Authorities (BAs)
Transmission Operators (TOPs)

Problem Statement
The transmission stability limits calculation (TSLC) application became unavailable twice during a five-hour period. The first interruption was for a period of two hours and the second for 30 minutes. During the time that the application was unavailable, the transmission stability limits were not updated, but thermal real-time limits and post contingency limits were still available during that time.

Details
A planned firmware update to the firewall caused a communication interruption of an archiving function related to the TSLC application. When the system operator (SO) was alerted of the situation, the SO was able to use the last limits updated by the TSLC application prior to its unavailability. These limits were still accurate during the unavailability of the TSLC application since there were no configuration changes on the power system during this period. However, if there were scheduled configuration changes on the bulk power system, the SOs at the system control center (SCC) would apply an operating instruction that would allow them to stop any work on the system and, if needed, the engineering support team will use the TSLC application tables manually to provide the limits to the SO at the SCC.

Upon acknowledging the communication interruption of the archiving function, service was transferred to the secondary server to restart the primary server in an attempt to reset the archiving function. Even though the primary server restart caused a hardware failure, the TSLC application service remained available on the secondary server.

With the secondary server still available, the SO was alerted that the stability limits were not updated. The limits provided by the TSLC application were sent to the energy management system (EMS) through a utility server, but the utility server was not able to maintain the communication link for longer than two hours after the interruption of the primary server. The inability to maintain this communication link caused the interruption of service and the related alerts. Upon completion of the diagnostic, the required actions to restore the service were identified and the TSLC application was restored on the secondary server.

When the second application interruption occurred, the SO was alerted that the stability limits were not updated. However, the TSLC application was restored on the secondary server by performing the same actions that were performed for the first interruption, thereby restoring the primary server of the TSLC application.

The first finding of the investigation was that the utility server was unable to maintain its communication due to a queuing process overflow in the EMS application.

A second finding showed that the archiving function interruption was caused by the use of a sharing protocol that proved sensitive to communication interruptions.

Corrective Actions

The EMS application update introduced a fix for its queuing overflow problem by clearing the queue upon the process start-up. After testing the software update, the EMS application was deployed in the production environment.

A plan is in progress to replace a sharing protocol with a more reliable method of transferring data. The sharing protocol needs to be replaced by a less sensitive protocol as there is no possible mitigation of the communication interruption during this required firewall update in its present configuration.

Lesson Learned

Diagnostic information provided by the monitoring functions must provide sufficient information to minimize the time to pinpoint the cause of the service interruptions when alert conditions are displayed. Supplemental functions that are critical to operations must be designed to provide sufficient diagnostic information.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

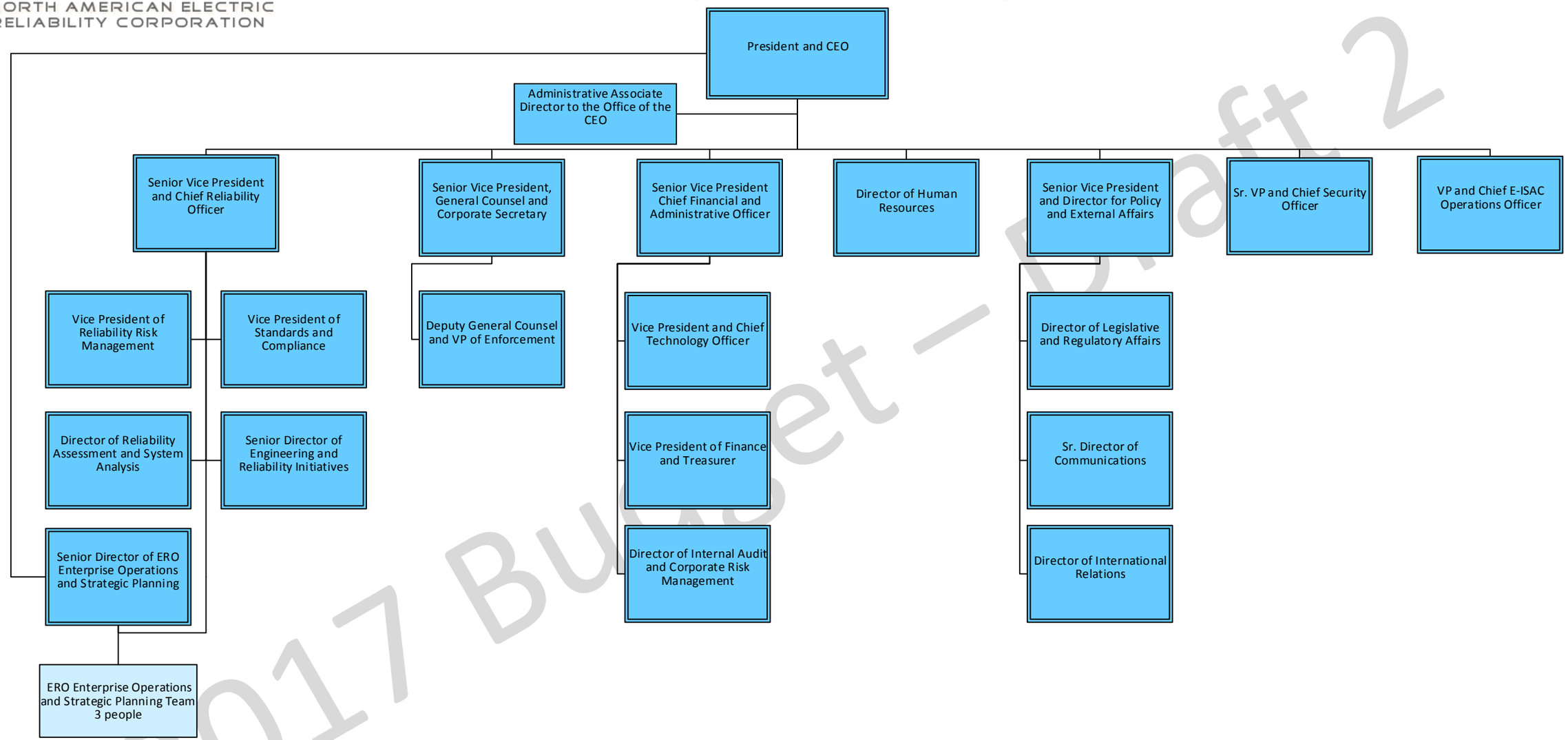
Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	NPCC – Event Analysis
Source of Lesson Learned:	Northeast Power Coordinating Council
Lesson Learned #:	20160701
Date Published:	July 5, 2016
Category:	Communications

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

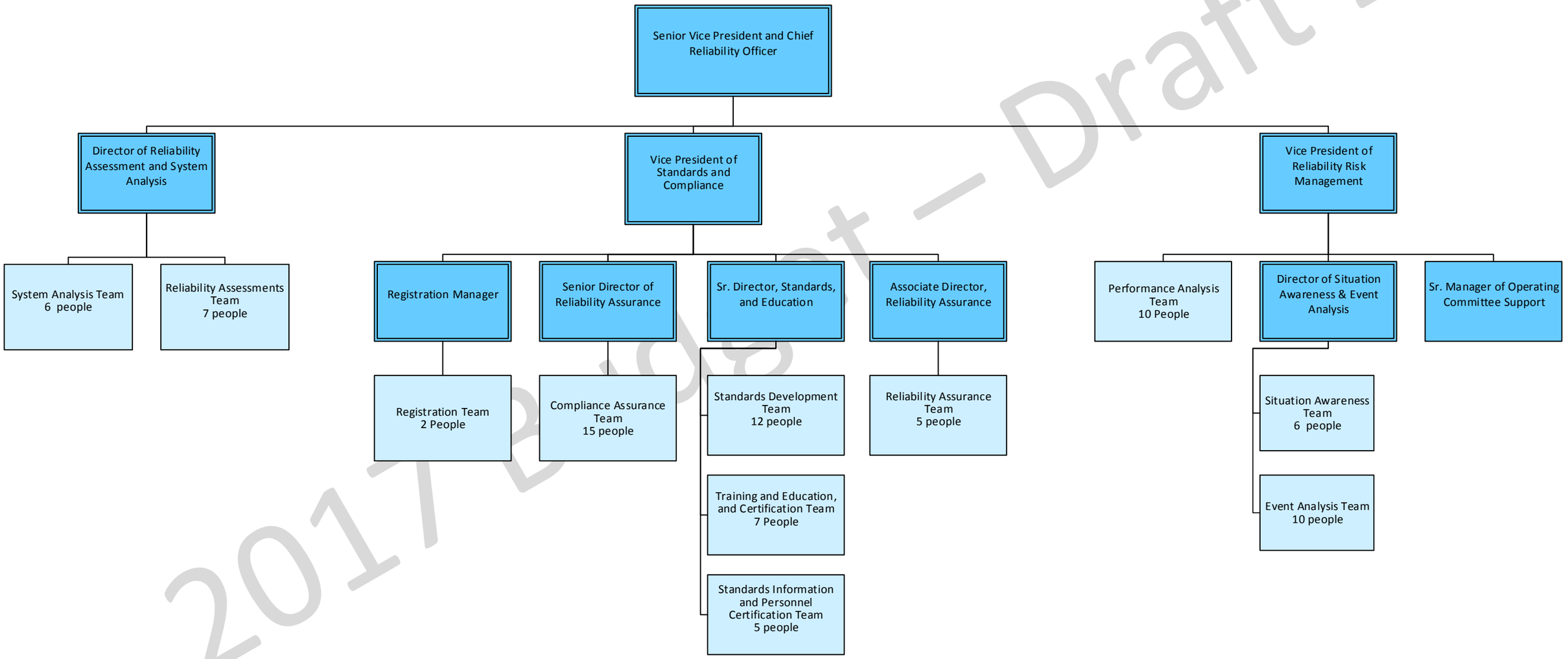
NERC Staff Organization Chart – Budget 2017



2017 Budget – Draft 2

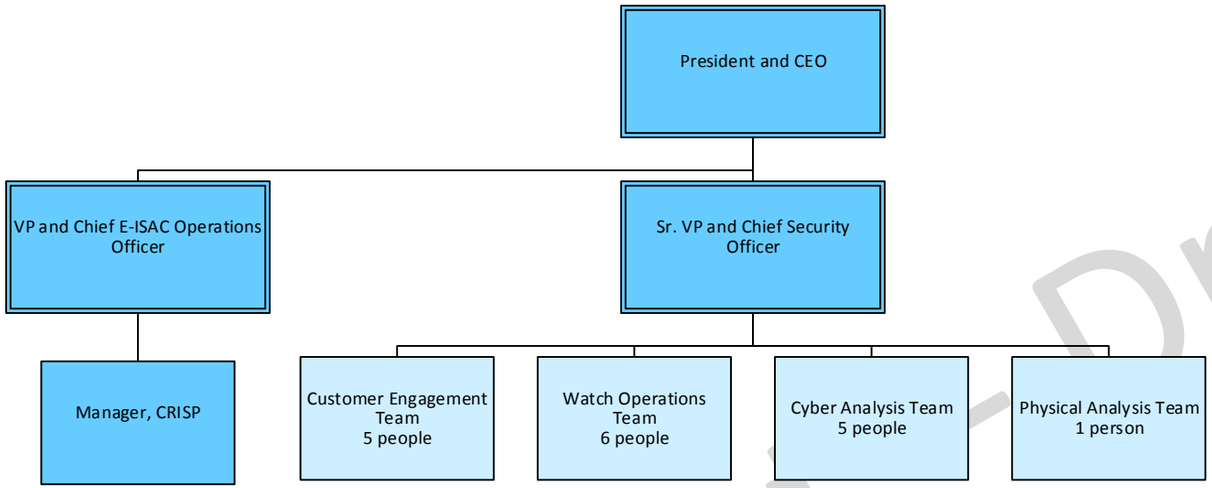
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Reliability Standards, Reliability Assurance, Reliability Assessment and System Oversight, Performance Analysis, Event Analysis, Situation Awareness, Training and Education



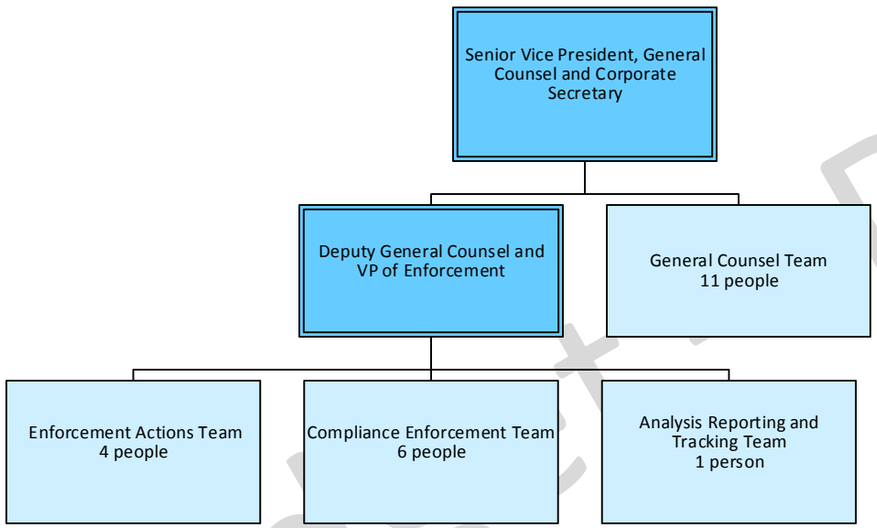
2017 Budget – Draft 2

Electricity Information Sharing and Analysis Center



2017 Budget – Draft 2

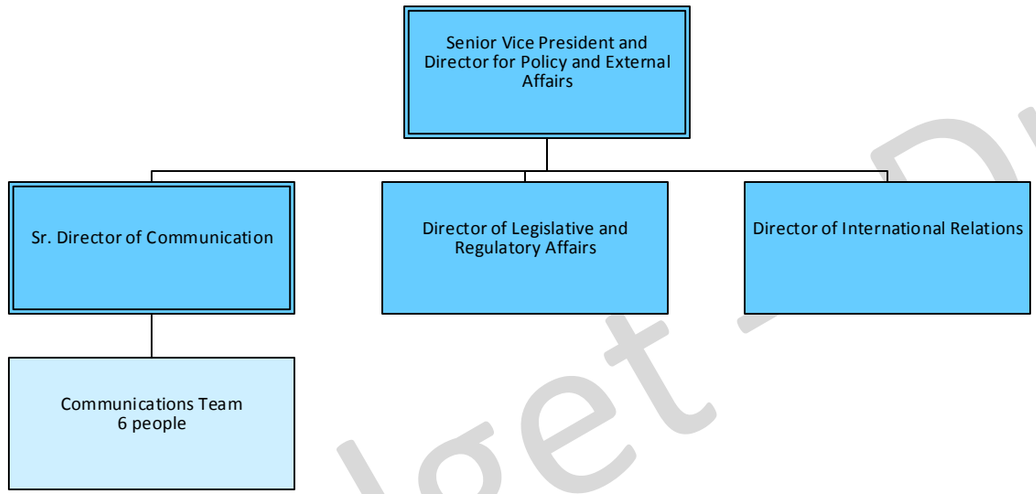
Legal and Regulatory
Compliance Enforcement



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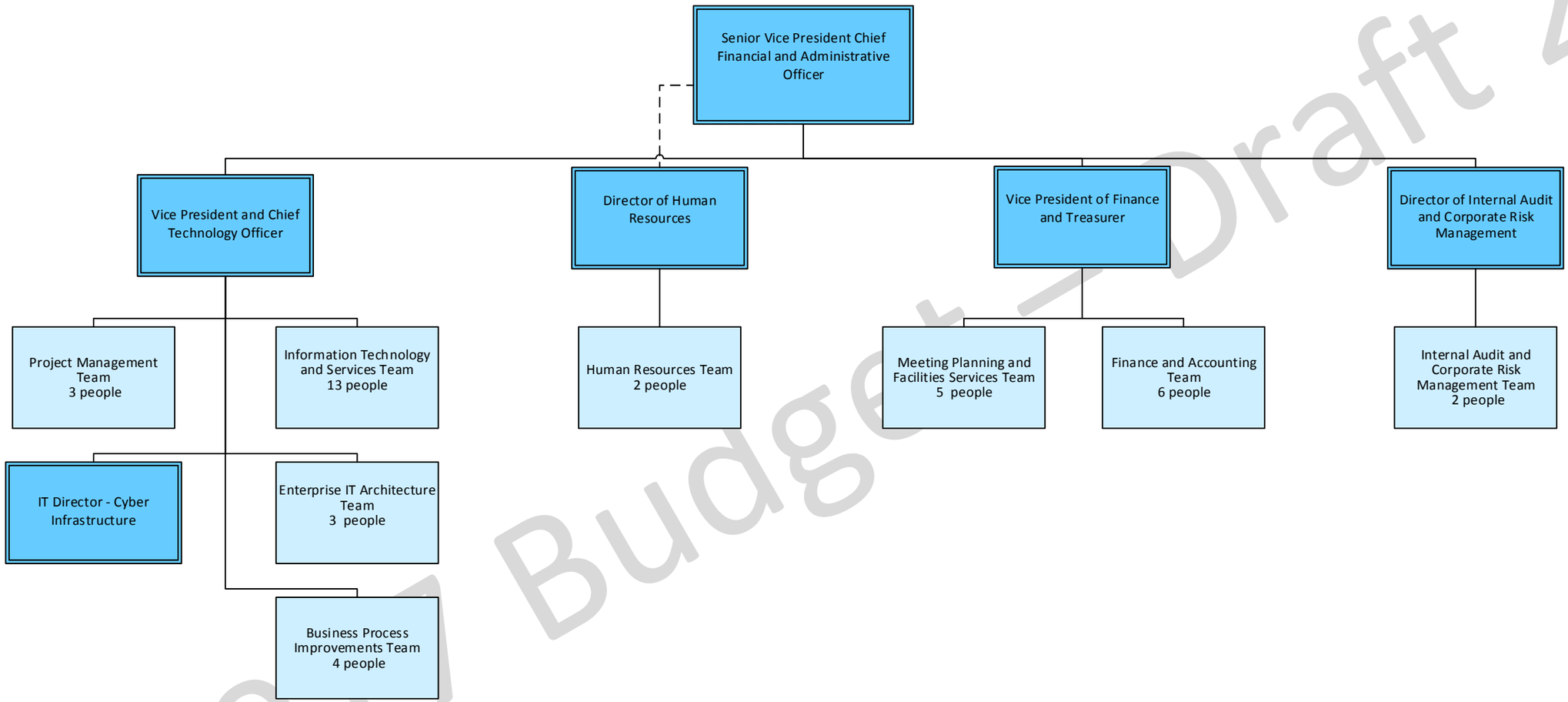
Policy and External Affairs



Telecommuter
Atlanta
Washington, DC
Unbudgeted 015

2017 Budget - Draft 2

Information Technology, Human Resources, and Accounting & Finance



2017 Budget – Draft 2

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Michael Walker
Senior Vice President
Chief Financial and Administrative Officer

July 15, 2016

RE: Updated Draft of NERC's 2017 Business Plan and Budget, Final Regional Entity 2017 Business Plans and Budgets Available on NERC's Website

On May 19, 2016, NERC posted the first draft of the 2017 Business Plans and Budgets for NERC and the Regional Entities. A webinar was conducted on May 26, 2016, to review the NERC, Regional Entity, and consolidated budgets and assessment projections. Written comments on the first draft of NERC's Business Plan and Budget were received from three entities and posted on NERC's website.

The primary change from NERC's first draft was to incorporate additional details and funding for improvements to the E-ISAC portal, which were discussed during the presentation of the first draft of NERC's 2017 budget. The text of the RAPA and E-ISAC sections were also updated and minor refinements to personnel, contract and consulting, and operating expense projections are also incorporated into this draft. Excluding the added costs and assessment funding related to the E-ISAC portal, the overall NERC budget and assessment increase remained the same as the first draft.

The net effect of the foregoing budget revisions is a total 2017 NERC budget of $69.6M, representing an increase of $2.4M (3.6%) over 2016. Total average assessments are projected to increase by $2.8M (4.9%) over 2016. After taking into account preliminary projections of credits to certain Canadian entities pursuant to NERC's Expanded Policy on Allocation of Certain Compliance and Enforcement Costs, the U.S., Canadian and Mexico assessments will increase $2.5M (4.9%), $217.2k (4.2%) and $17.2k (10.8%)[1], respectively.

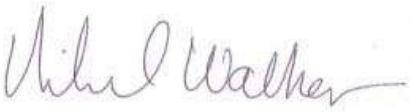
NERC has posted on its website, under the Business Plan and Budget page, the second draft of the 2017 Business Plan and Budget and a presentation which provides an overview of the aforementioned changes and other relevant information. The final 2017 Business Plans and Budgets for all of the Regional Entities (and Western Interconnection Regional Advisory Body) are also posted with their associated presentations. Additionally, NERC posted responses to comments related to the first draft of the Business Plan and Budget. Finally, we have posted a presentation which includes an ERO Enterprise consolidated budget for 2017 and a consolidated projection of costs and assessments for 2018 and 2019.

[1] Increase due largely to a significant increase in Mexico's NEL share

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The NERC Finance and Audit Committee will meet to review these materials via conference call and webinar on July 21, 2016, at 11:00 a.m. Eastern. Written comments are requested by July 29, 2016, and should be directed to the attention of Anya Josephson at BudgetComments@NERC.net.

As always, we both appreciate and look forward to your feedback.



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NERC 2017 Business Plan and Budget Draft 2 Overview

NERC Finance and Audit Committee Conference Call
July 21, 2016

RELIABILITY | ACCOUNTABILITY






Major Areas of Focus

- Activities supporting
  - Goals and objectives in the Strategic Plan
  - RISC Priorities
  - Standing Committees
- Increasing NERC's analytical capabilities
- E-ISAC operations
- Enterprise Risk Management
- Highly skilled workforce
- Resource allocation and efficiency of operations

Updates since Draft 1

- Personnel Costs and Assumptions
  - Updated personnel allocations and costs based on latest projections
  - FTEs are slightly lower than Draft 1
  - Minor changes in other personnel categories
- Updated budget to reflect funding of further improvements to E-ISAC portal
- Other costs remain close to Draft 1, with minor adjustments

2017 Budget – Draft 2 Summary

- Total NERC before additional E-ISAC portal investment
  - Budget increase unchanged at 2.5%
  - Assessment increase unchanged at 4.5%
- Total NERC with additional E-ISAC portal investment
  - Adds another 1.1% to total budget increase
    - 3.6% overall, 3.5% without CRISP
  - Adds another 0.4% to total assessment increase
    - 4.9% overall, 4.7% without CRISP
    - Includes release of $1.1M in Assessment Stabilization Reserves
- CRISP
  - Finalizing budget with Battelle and participants
  - Anticipate minimal changes between 2016 and 2017

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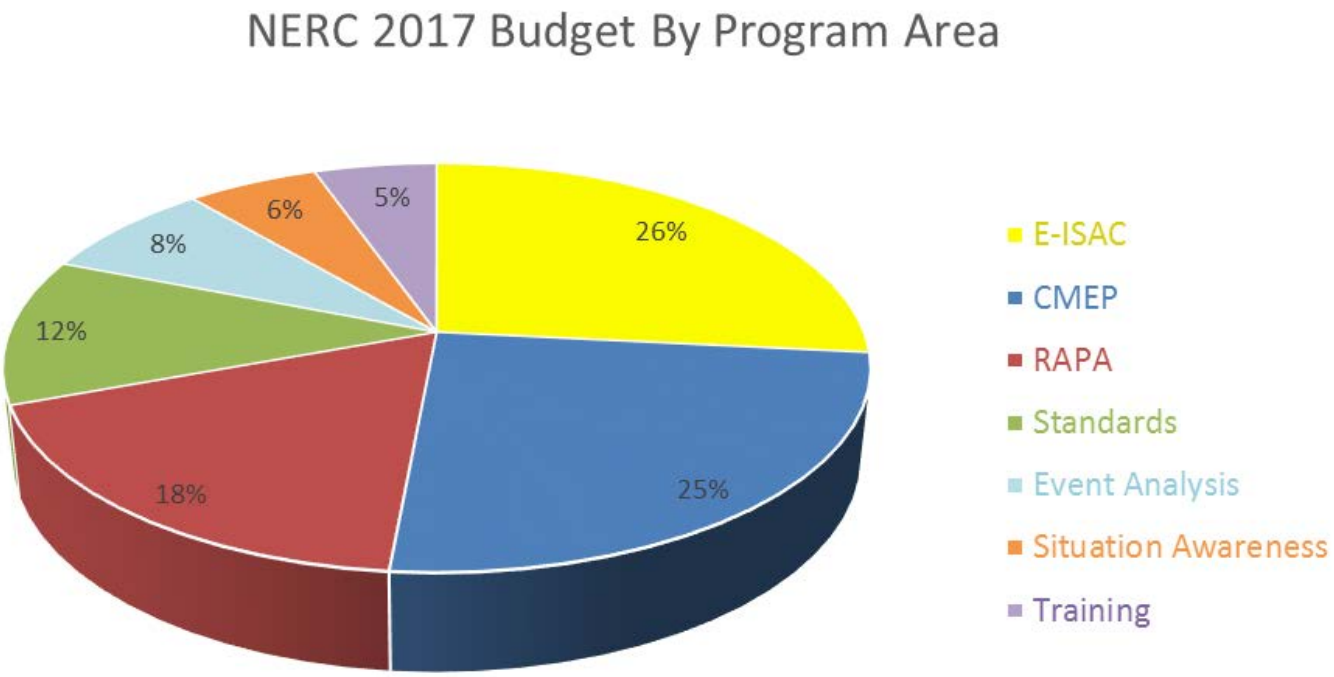
2017 Budget – Draft 2 Summary

	2016 Budget	2017 Budget	Variance $ Over(Under)	Variance % Over(Under)
Expenses				
Personnel Expenses	$ 37,283,807	$ 38,641,331	$ 1,357,525	3.6%
Meeting Expenses	3,620,286	3,372,886	(247,400)	-6.8%
Operating Expenses	24,903,515	24,800,690	(102,825)	-0.4%
Other Non-Operating Expenses	110,000	106,725	(3,275)	-3.0%
Total Expenses	**$ 65,917,608**	**$ 66,921,632**	**$ 1,004,024**	**1.5%**
Inc(Dec) in Fixed Assets	1,269,057	2,680,543	1,411,486	111.2%
TOTAL BUDGET	**$ 67,186,665**	**$ 69,602,175**	**$ 2,415,510**	**3.6%**
FTEs	**192.47**	**189.88**	**(2.58)**	**-1.3%**

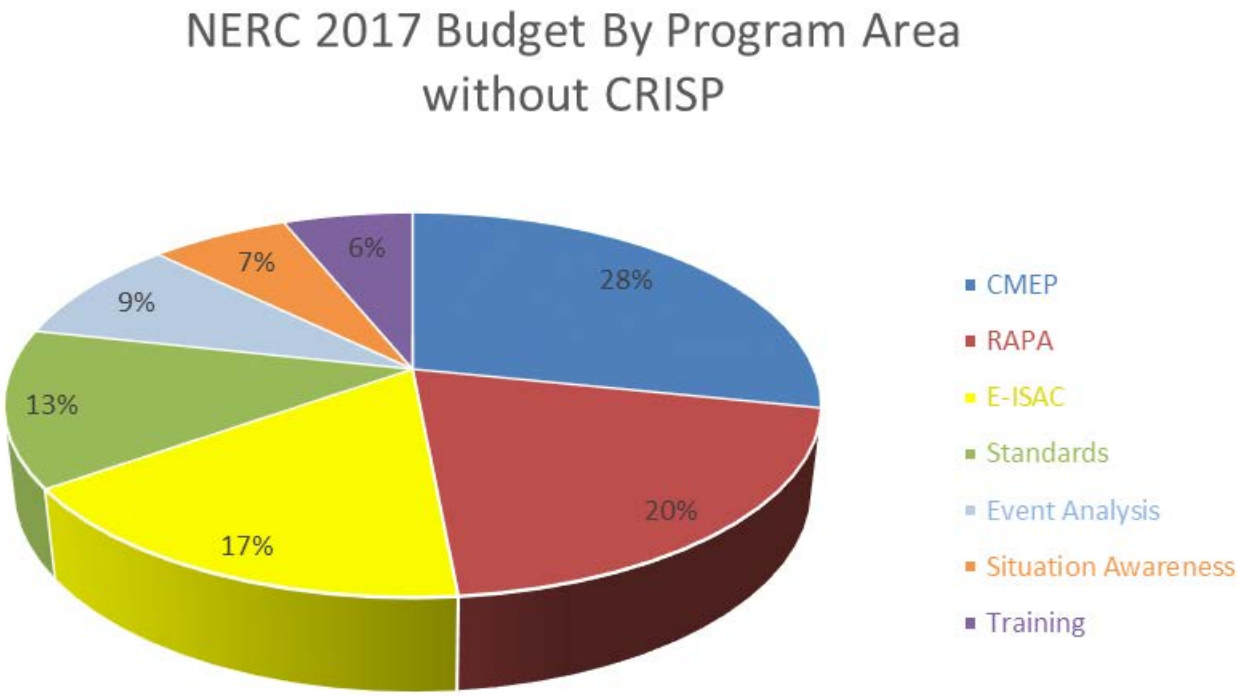
- Personnel expenses include salaries, at-risk incentive compensation, benefits, temporary staffing, and training. In addition to those categories, overall personnel expense is increasing in part due to lower attrition and stabilizing workforce.

- Change in fixed assets, excluding depreciation and allocations, is an increase of $461,000.

Budget By Program Area

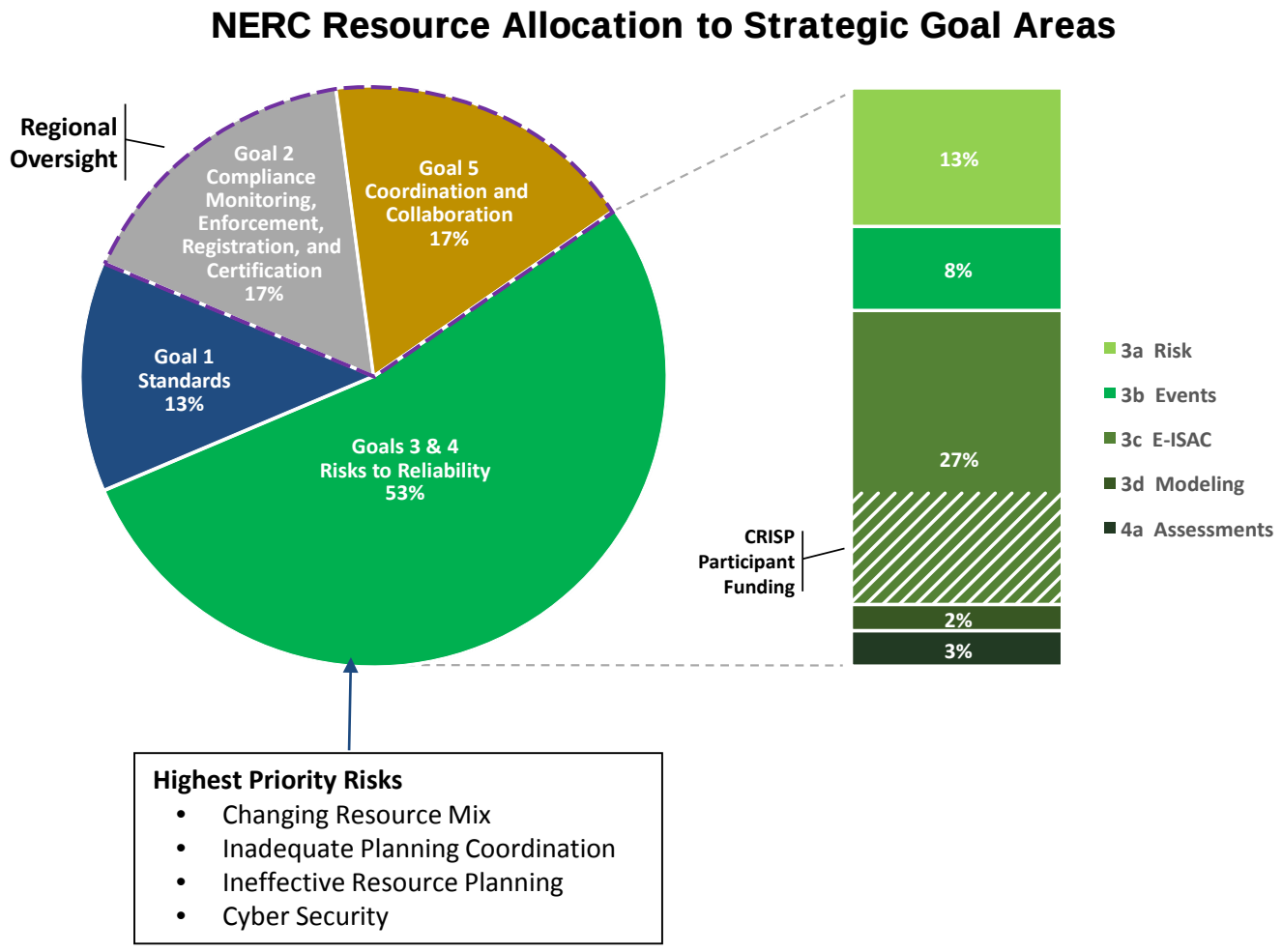


Budget By Program Area without CRISP



Note: CRISP is funded largely by third-parties. This chart reflects the distribution of resources funded primarily by assessments.

NERC Resource Allocation to Strategic Goal Areas



Assessment Stabilization Strategy

- Multi-year strategy to better align budget increases, assessment requirements, and billed assessments
- Phased release of Assessment Stabilization Reserves*
  - 2017 assessment increase at 4.5%
  - 2018 assessment increase +/- 3.8%
  - 2019 assessment increase +/- 3.1%
  - 2020 and beyond +/- 3.0% declining toward 2.7%
- Actual budget increases and use of reserves determined annually

* Assumed 2.5% budget increase for modeling purposes

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Assessment Stabilization Reserve Projection / Recommendation

- Assessment Stabilization Reserve projected at $2,171,000
  - Balance at beginning of 2016
    - $2,271,000
  - Received $500k penalty funds in May 2016
    - $2,771,000 balance at end of 2016
  - $500k penalty funds scheduled to be received in May 2017
    - Recommend deposit into the stabilization reserve when these funds become unrestricted under current accounting policy
  - Recommend using $1,100,000 in 2017 to offset assessments
    - $2,171,000 projected remaining balance for 2017
    - Assumes May 2017 $500k penalty funds contributed to this reserve

Other Reserve Balances Projected 2017 Year-End

- Future Obligation Reserves - $2.6M
- Operating Contingency Reserve - $2.2M
  - Conservative projection, generally target $2M
- System Operator Certification Reserve - $714k
- CRISP Reserve - $500k
  - Funded by participants, subject to final budget negotiation

Assessment Increases by Country

- Total NERC Assessment Increase – 4.9%
  - U.S. Increase – 4.9%
  - Canada Increase – 4.2%
  - Mexico Increase – 10.8%
    - Primarily resulting from an increase in NEL

Total Canadian Assessments

DRAFT 2	% Change - 2017 v 2016			$ Change - 2017 v 2016		
	Total Assessment	RE Assessment	NERC Assessment	Total Assessment	RE Assessment	NERC Assessment
AESO	-5.1%	-10.2%	5.9%	$ (82,120)	$ (112,454)	$ 30,334
IESO	1.2%	-0.1%	3.3%	37,473	(1,499)	38,972
New Brunswick	0.6%	-2.0%	7.3%	2,567	(5,939)	8,506
Quebec	0.5%	-0.5%	2.1%	23,121	(14,651)	37,772
Nova Scotia	-0.1%	-3.1%	5.0%	(304)	(7,528)	7,224
Manitoba Hydro	-3.1%	-4.6%	1.2%	(38,907)	(42,827)	3,920
SaskPower	1.5%	-0.1%	6.0%	18,128	(590)	18,718
British Columbia Hydro	3.0%	0.6%	9.1%	82,930	11,203	71,728
Total Canada	**0.3%**	**-1.7%**	**4.2%**	**$ 42,889**	**$ (174,284)**	**$ 217,173**

Budget / Assessment Trend

- NERC's assessment increasing more than Regions for a variety of reasons
- Broader responsibilities
  - E-ISAC
  - ERO Enterprise application development and maintenance
  - Broader analytical needs and capabilities
- Personnel costs represent majority of costs
  - Larger workforce
  - Even stable workforce yields upward pressure on budget

Remaining Calendar

- July 15 - Draft 2 posted
- July 29 - Comments due on Draft 2
- August 10 – FAC Open meeting
- August 11 – NERC Board meeting
- August 24 – FERC Budget Filing



Questions and Answers

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2017 Business Plan and Budget

Draft 2

July 15, 2016

RELIABILITY | ACCOUNTABILITY






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About NERC

Overview

The North American Electric Reliability Corporation (NERC) is a not-for-profit entity organized under the New Jersey Nonprofit Corporation Act. NERC's mission is to improve and ensure the reliability of the Bulk Power System (BPS)[1] in North America. NERC's area of responsibility spans the continental United States and portions of Canada and Mexico. Entities under NERC's jurisdiction are the users, owners, and operators of the BPS—a system that serves the needs of over 340 million people, includes installed electricity production capacity of approximately 1,200 gigawatts, operates 475,000 miles of high-voltage transmission (100 kV and above), and is comprised of assets worth more than one trillion dollars.

Electric Reliability Organization (ERO)

The Federal Energy Regulatory Commission (FERC or Commission) certifies and has oversight of NERC as the electric reliability organization (ERO) within the United States to establish and enforce reliability standards for the U.S. portion of the BPS, pursuant to Section §215 of the Federal Power Act (§215).[2] As of June 18, 2007, FERC granted NERC the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the BPS and made compliance with those standards mandatory and enforceable. Equivalent relationships have been sought and, for the most part, realized in Canada and Mexico.

International Relations

Prior to adoption of §215 in the United States, the Canadian provinces of Ontario (in 2002) and New Brunswick (in 2004) adopted all NERC reliability standards that were approved by the NERC Board of Trustees (Board) as mandatory and enforceable within their respective jurisdictions through market rules. Reliability legislation is in place, or NERC has memoranda of understanding with, provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, Manitoba, Saskatchewan, British Columbia, and Alberta, and with the National Energy Board of Canada (NEB). NERC's standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. Manitoba has adopted legislation, and standards are also mandatory. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transmission Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC reliability standards are now mandatory in British Columbia and Nova Scotia. NERC and the Northeast Power Coordinating Council (NPCC) have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NEB has made reliability standards mandatory for international power lines between the U.S. and Canada.

In Mexico, the Comisión Federal de Electricidad has signed the Western Electricity Coordinating Council's (WECC's) reliability management system agreement, which applies only to Baja California Norte.

Membership and Governance

An 11-member Board of Trustees (the Board), comprised of 10 independent trustees and NERC's president and chief executive officer serving as the management trustee, governs NERC. The Board has formed several committees to facilitate oversight of the organization in the areas of finance and audit, governance and human resources, compliance, standards oversight and technology, nominations and, most recently, enterprise-wide risk.

[1] NERC's standards, compliance and enforcement activities are focused on the Bulk Electric System (BES), which is comprised of certain BPS facilities.

[2] ERO Enterprise Strategic Plan

Membership in NERC is open to any person or entity that has an interest in the reliability of the North American BES. Membership is voluntary and affords participants the opportunity to engage in the governance of the organization through election to the Member Representatives Committee (MRC).[3] More than 600 entities and individuals are members of NERC.

Scope of Oversight

As the international, multijurisdictional ERO in North America, NERC is authorized to:

- Propose, support the development of, monitor compliance with, and enforce mandatory reliability standards for the North American BPS, subject to regulatory oversight and approvals from FERC in the United States and applicable authorities in Canada;
- Conduct near-term and long-term reliability assessments of the North American BPS;
- Certify BPS operators as having and maintaining the necessary knowledge and skills to perform their reliability responsibilities;
- Maintain situational awareness of events and conditions that may threaten BPS reliability;
- Coordinate efforts to improve physical security and cybersecurity for the BPS of North America;
- Conduct detailed analyses and investigations of system disturbances and unusual events as well as measure ongoing system trends to determine root causes, uncover lessons learned, and issue relevant findings as advisories, recommendations, guidelines, and essential actions to the industry to mitigate and control risks to reliability; and
- Identify and prioritize risks to reliability and use a broad toolkit to mitigate and control risks to reliability, including the potential need for new or modified reliability standards, improved compliance monitoring and enforcement methods, or other initiatives.

Delegated Authorities

In executing its responsibility, NERC delegates certain authorities to eight regional reliability entities (Regional Entities or the Regions) to perform aspects of the ERO functions described through delegation agreements. FERC has approved delegation agreements between NERC and the eight Regional Entities (Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council, Inc. (NPCC), ReliabilityFirst, SERC Reliability Corporation (SERC), Southwest Power Pool Regional Entity (SPP RE), Texas Reliability Entity, Inc. (Texas RE), and the Western Electricity Coordinating Council (WECC)[4]). These agreements describe the authorities delegated and responsibilities assigned to the Regional Entities in the United States to address, among other things: (1) developing regional reliability standards, (2) monitoring compliance with and enforcement of mandatory reliability standards (both North American-wide and regional), (3) certifying registered entities and registering owners, operators, and users of the BES, (4) assessing reliability and analyzing performance, (5) training and education, (6) event analysis and reliability improvement, and (7) situation awareness and infrastructure security. NERC expects Regional Entities whose territories and geographic footprints extend into Canadian provinces and Mexico to perform equivalent functions in those jurisdictions.

[3] The Member Representatives Committee (MRC) comprises 28 voting representatives elected from the 12 membership sectors. The MRC elects the independent trustees and, along with the Board, votes on amendments to the Bylaws. The MRC also provides policy advice and recommendations to the Board on behalf of stakeholders with respect to annual budgets, business plans, and other matters pertinent to the purpose and operation of the organization.

[4] WECC has sub-delegated its Reliability Coordinator ("RC") function to Peak Reliability, which commenced operations and assumed the RC function within the WECC footprint on January 2, 2014.

ERO Enterprise Operating Model

The collective network of leadership, experience, judgment, skills, and technologies shared among NERC and the eight Regional Entities is referred to as the ERO Enterprise (the Enterprise). In 2014, a common operating model, Improving Coordinated Operations across the ERO Enterprise,[5] was developed to define how NERC and the Regional Entities achieve excellence in the oversight and execution of statutory functions by collaborating to mitigate reliability risks. The model also defines the division of the roles and responsibilities for NERC and the Regional Entities to efficiently and effectively execute services performed as the collective Enterprise. In 2015, implementation of this model progressed with oversight plans developed for Compliance Monitoring and Enforcement programs, and Registration. Further, NERC and the Regional Entities deepened its coordination activities to identify, prioritize and address risks to reliability.

NERC has unique responsibilities within the Enterprise to design the oversight of program areas; develop operational oversight and leadership; set qualifications and expectations for the performance of delegated activities; and assess, train, and give feedback to corresponding regional programs. NERC also reviews and provides input to the annual Regional Entity business plans and budgets, including but not limited to review of resource allocations, staffing capacity assessments, and program performance assessments. NERC input and review occurs before regional board approval.

Similarly, the Regional Entities have a mirrored set of responsibilities that include being responsive to the design of the operational model, providing input into the overall development of each ERO program area, providing training and development to meet ERO qualifications, being receptive to feedback from the ERO, and making responsive adjustments. Regional Entities also have an obligation to meet professional standards of independence and objectivity, and provide the best available expertise for addressing risks.

With due recognition and awareness of the distinction between individual roles, responsibilities, and corporate status, NERC and the Regional Entities are continually refining their individual and collective operating and governance practices in support of an agreed-upon set of strategic goals and objectives that are designed to ensure the ERO fulfills its statutory obligations.

Statutory and Regulatory Background

NERC's authority as the ERO in the United States is based on Section 215 of the Federal Power Act, as added by the Energy Policy Act of 2005,[6] and the Commission's regulations and orders issued pursuant to Section 215. In Canada, NERC's authorities are established by the memoranda of understanding and regulations previously mentioned.

Funding

Section 215 of the Federal Power Act and the Commission's regulations specify procedures for NERC's funding in the United States. NERC's annual business plan and budget is subject to Commission approval in the United States. Once approved, NERC's annual funding is provided through assessments to load-serving entities. These assessments are allocated on a net-energy-for-load (NEL) basis. Equivalent funding mechanisms are provided in Canada, subject to the specific laws and regulations of each province.

The Regional Entities' funding requirements are addressed separately in their respective business plans and budgets, which must be reviewed and approved by NERC and FERC in the United States. Assessments for the Regional Entity budgets are included in the overall NERC assessments to load-serving entities.

[5] Improving Coordinated Operations Across the ERO Enterprise

[6] This was codified in section 215 of the Federal Power Act, 16 United States C. 824o.

Introduction and Executive Summary

TOTAL RESOURCES (in whole dollars)	2017 Budget	U.S.	Canada	Mexico
Statutory FTEs	189.88			
Non-statutory FTEs				
Total FTEs	189.88			
Statutory Expenses	$ 66,921,632			
Non-Statutory Expenses	$ -			
Total Expenses	$ 66,921,632			
Statutory Inc (Dec) in Fixed Assets	$ 2,680,543			
Non-Statutory Inc (Dec) in Fixed Assets	$ -			
Total Inc (Dec) in Fixed Assets	$ 2,680,543			
Statutory Change in Reserves Requirement	$ (69,598)			
Non-Statutory Change in Reserves Requirement				
Total Working Capital Requirement	$ (69,598)			
Proceeds from Financing Activities	$ 19,083			
Total Statutory Funding Requirement	$ 69,551,660			
Total Non-Statutory Funding Requirement	$ -			
Total Funding Requirement	$ 69,551,660			
	TOTAL	**US**	**CANADA**	**MEXICO**
Statutory Funding Assessments	$ 59,856,314	$ 54,326,337	$ 5,353,026	$ 176,951
Non-Statutory Fees				
NEL	4,514,633,135	3,983,687,261	518,227,758	12,718,116
NEL%	100.00%	88.24%	11.48%	0.28%

Strategic Goals and Metrics

The ERO Enterprise strategic plan and framework informed by the following activities completed in 2015: (1) NERC's State of Reliability Report; (2) the Reliability Issues Steering Committee's (RISC's) ERO Reliability Risk Priorities Report and Supplemental Technical Summary, which includes identified risk profiles; and (3) input from the NERC Board and Regional Entity Boards. In 2015, these inputs were used by ERO Enterprise leadership to:

- **Update ERO Enterprise Longer-term Strategic Planning Considerations** – The ERO Enterprise makes any necessary adjustments to its longer-term strategic planning considerations, which takes into consideration Bulk Electric System (BES) reliability issues over a 5 to 15-year planning horizon.
- **Update the Three-year ERO Enterprise Strategic Goals** – The ERO Enterprise makes any necessary adjustments to its strategic goals for the next three years.
- **Develop Annual ERO Enterprise Metrics** – The ERO Enterprise develops annual metrics to measure the ERO Enterprise's progress in attaining the strategic goals.
- **Develop Annual Business Plans and Budgets** – Working collaboratively, NERC and each of the Regional Entities develop annual business plans and budgets (BP&Bs) that reflect the resources necessary to support achievement of the goals set forth in the strategic plan.

Evolving Reliability Risks

Over the past five years, NERC has transformed its activities towards being more risk-based, ensuring that the right activities are focused on the most pertinent risks to the reliable operation of the bulk power system. The RISC is an advisory committee to the Board, providing key insights, priorities, and high-level leadership for issues of strategic importance to BPS reliability. The 2015 RISC report presents the results of their continued work to define and prioritize risks, and offer recommendations to the Board to inform the development of NERC's risk strategy. The report recommendations are considered as the Strategic Plan, Goals and supporting activities are updated for the coming years. In 2015, the RISC recommended a high level of focus and priority in the following areas:

- **Regulatory Uncertainty (Markets, states, and federal/provincial)**
  These risks arise where the impacts from regulatory initiatives are uncertain in their extent, timing, and potential reliability considerations. These uncertainties are accentuated by the interplay among these three arenas, each of which reflects policy, regulatory, and legislative dimensions which may not include sufficient reliability coordination.

- **Resources (Changing resource mix, inadequate planning coordination, and ineffective resource planning)**
  This set of evolving risks reflects interdependent aspects from the continued and accelerated rapid transformation of the resource mix. As part of the increased and accelerated integration of new types of variable, renewable, and distributed energy resources, planners must ensure that sufficient ERSs and operator flexibility are available to maintain reliability.

- **Resiliency: Cyber security**
  These risks reflect aspects of resilience related to potential cyber disruptions of the BPS. As cyber aspects evolve, they require more assertive and flexible approaches to provide adequate assurances of reliability.

2016-2019 Strategic Goals

The ERO Enterprise has five strategic goals, adopted by the NERC Board in November 2015, enabling it to successfully carry out its mission as further described in the Strategic Plan. For each goal, a detailed description is provided, activities that contribute to its success, and additional information about the allocation of NERC's resources toward their achievement are noted below. The associated metrics in support of these goals have been approved for 2016[7]; updated strategic goals and associated metrics will be finalized later in 2016 for the 2017 year, with opportunities for stakeholder feedback prior to their approval. At this time it is not anticipated that these updates will have a material impact on NERC's overall budget or resource allocation among operating areas for 2017. However, the updates may potentially affect priorities and workload within particular departments and will inform resource planning and allocation for the 2018 budget year.

Goal 1
Timely and Risk-Responsive Reliability Standards

Reliability standards establish threshold requirements for assuring the BES is planned, operated, and maintained to minimize risks of cascading failures, avoid damage to major equipment, or limit interruptions of bulk electric supply. Reliability standards are clear, timely, responsive to reliability risks and cost-effective.

Contributing Activities

- Conduct periodic reviews and assessment of whether the reliability standard is properly structured for emerging risks.
- Assess reliability standards compared to the BES risk profile; address the most important unmitigated risks, including applicable high-impact, low-frequency risks.
- Develop and implement ERO Enterprise feedback loops to identify and address gaps or ambiguities in reliability standards, including the evaluation of significant BES events (including all category 3 and above).
- Develop and implement procedures for assessing the cost impact of reliability standards.

Goal 2
Objective and Risk-informed Compliance Monitoring, Enforcement, and Organization Certification and Registration

The ERO Enterprise is a strong enforcement authority that is independent, without conflict of interest, objective, and fair, and promotes a culture of reliability excellence through risk-informed compliance monitoring, enforcement, certification, and registration.

Contributing Activities

- Consistently register and deregister entities based on risk to the BES and the BES definition.
- Evaluate the certification program for effectiveness and implement consistently across the ERO Enterprise.
- Develop Compliance Oversight Plans for registered entities that address the relevant risks.
- Focus Compliance Monitoring and Enforcement activities on the most significant risks to the BES.
- Process non-compliance using the appropriate method, considering the risk to the BES.

[7] See 2016 ERO Enterprise and Corporate Metrics for details.

- Implement Compliance Monitoring and Enforcement consistently, timely, and transparently to industry.

Goal 3
Identification and Mitigation of Significant Current Risks to Reliability

The ERO Enterprise identifies the most significant risks to reliability, provides assurance for mitigating reliability risks, and promotes a culture of reliability excellence. The ERO Enterprise supports the Electricity Information Sharing and Analysis Center (E-ISAC), the Cybersecurity Risk Information Sharing Program (CRISP), reliability assessments, situational awareness, and physical security and cybersecurity preparedness.

Contributing Activities

- Perform reliability data-grounded analyses and sustain independent, technical assessments of proposed regulatory rules or proposed statutes (state, provincial, or federal) as well as significant market rules to determine potential impacts to reliability.
- Maintain a BES risk profile to prioritize and rank reliability risks.
- Develop project plans and business case assessments for high-priority risks including cost and practicality of assessment; implement or facilitate initiatives to address high-priority risks.
- Integrate risk data sources, such as event analysis, Transmission Availability Data System, Generating Availability Data System, and relay misoperations as well as other occurrences (e.g., AC equipment failures) to provide lessons learned, recommendations, identified risks, and their mitigation to promote reliability.
- Analyze system performance and significant events (e.g., sampling of Category 2 events in addition to assessing all Category 3 and above) to identify gaps in reliability standards, compliance effectiveness, registration, and risk controls effectiveness, as well as the development of lessons learned or other information sharing activities that promote BES reliability.
- Enhance communications among the E-ISAC, the Telecommunications Information Sharing and Analysis Center, and Natural Gas Information Sharing and Analysis Center.
- Facilitate the availability, sharing and value of physical security and cybersecurity threat and vulnerability information, analytics, and analysis.

Goal 4
Identification and Assessment of Emerging Risks to Reliability

The ERO Enterprise identifies, evaluates, studies and independently assesses emerging risks to reliability.

Contributing Activities

- Develop sufficiency/adequacy guidelines for essential reliability services (ERS) including emerging risks. Include consideration of the range of reliability attributes based on a diverse resource mix and load behavior, such as ramping, fast regulation, reserve services, and interdependent sector performance.
- Enhance reliability assessments to reflect changing resource mix behavior, including distributed energy resources and ERS, with probabilistic approaches, considering the variable and energy-limited nature of the resource shifts.
- Evaluate the impacts on BES recovery and restoration plans including consideration of distributed resources.

Goal 5
Effective, Efficient, and Collaborative ERO Enterprise

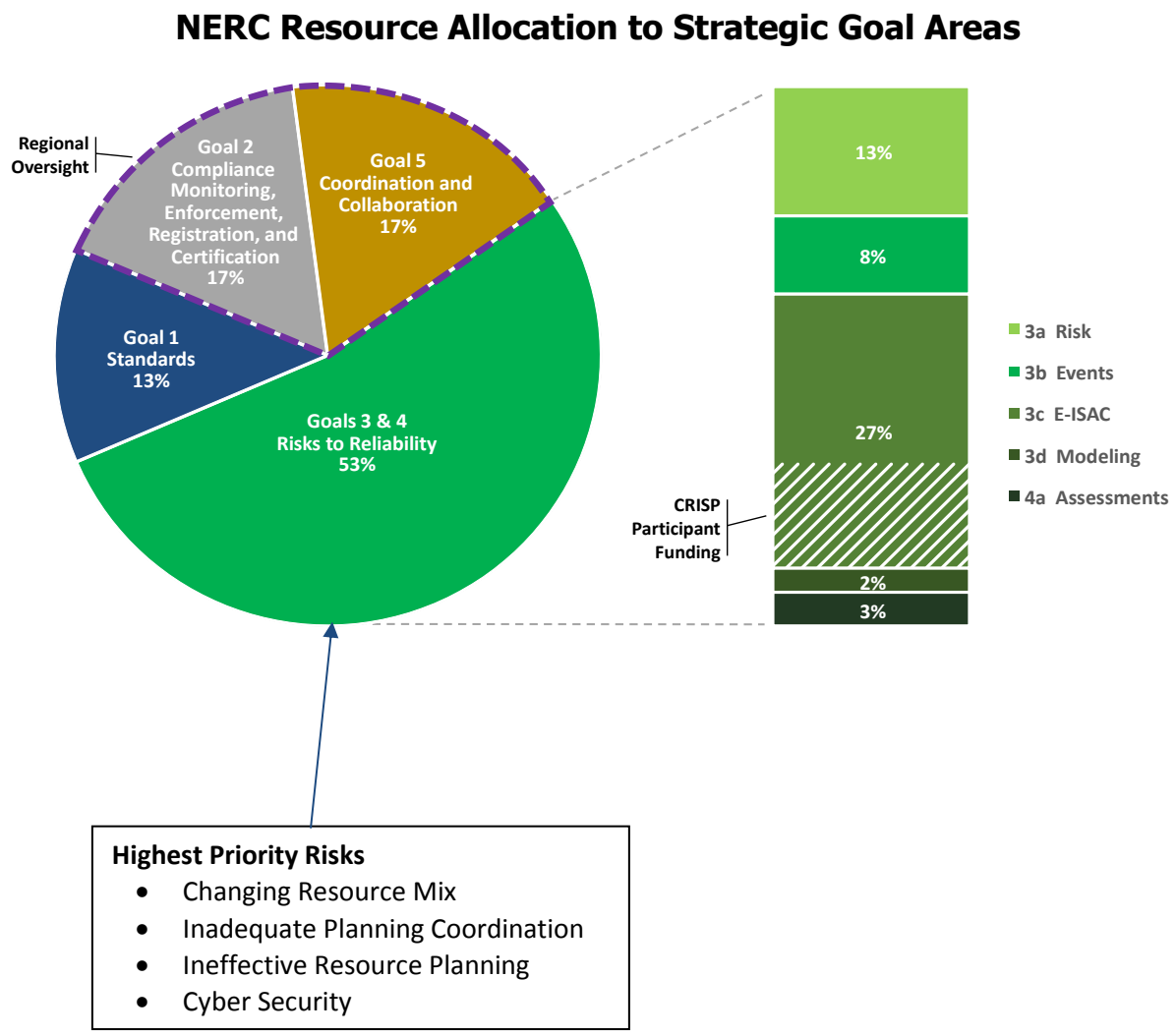
The ERO Enterprise improves transparency, consistency, quality, efficiencies, cost-effectiveness, and timeliness of results and operates as a collaborative enterprise.

Contributing Activities

- Articulate a shared vision of reliability excellence and support and inspire stakeholders continent-wide, including in international jurisdictions, in working to attain that vision.
- Engage the support and expertise of stakeholders in prioritizing and resourcing reliability initiatives.
- Communicate expectations clearly and foster collaboration to deliver important results in advancing system reliability.
- Acquire, engage, and retain highly qualified talent with requisite technical expertise to execute the ERO Enterprise's statutory functions.
- Understand and manage ERO Enterprise internal risks.
- Processes and procedures are consistent, effective, and efficient.
- Clearly delineate ERO Enterprise roles and responsibilities using the ERO Enterprise Operating Model to mature the collaborative processes.

Allocation of NERC Resources to Strategic Goals and Risk Priorities

The charts below provide an overview of the allocation of NERC's 2017 resources associated with each strategic goal, as well as the RISC priorities. Using FTEs and funding as a guide, the charts reflect the relative amount of total NERC resources (people and dollars) focused on supporting each of the five strategic goals noted above. Obviously many NERC departments work on multiple activities that further multiple goals, and precision in forecasting all activities supporting each goal is not practical. However, these charts provide a general picture regarding how the company's resources are allocated.



Ongoing Focus on Cost Control and Efficiency

NERC and the Regional Entities continue to work collaboratively to improve efficiency, evaluate resources, and leverage combined skillsets to improve various ERO Enterprise activities and control costs. This collaboration and the resulting efficiencies can be found in a number of areas, including but not limited to:

- **ERO Enterprise IT Investments:** NERC and the Regional Entities, working collaboratively with oversight of NERC's Standards Oversight and Technology Committee, have developed a long-term enterprise information technology program resulting in a number of enterprise tools. The goals is to enhance operations and reduce costs at the regional and registered entity level. For example, enterprise tools have helped and will further facilitate efficiency of registration and data submittals, improved consistency in registered entity resources devoted to compliance, and improved overall reliability through information sharing on Events Analysis and Situation Awareness.
- **Enforcement**: NERC has worked closely with Regional Entities to streamline enforcement staff in connection with the development of more efficient and risk-based enforcement mechanisms.
- **Standards:** As standards development has matured, NERC management has reduced standards staff allocations towards more critical activities like cyber security and analytical capabilities.
- **Legal:** As a result of the aforementioned efficiencies and the maturity of NERC's and ERO Enterprise's business processes, the legal department has reduced its resource requirements, reallocating limited resources to more critical priorities without impacting the company's overall staffing requirements.
- **Forums**: As further described in the quarterly forum reports to the NERC Board of Trustees, NERC and the Regional Entities continue to leverage the transmission and generation forums to jointly address risks to reliability to mitigate their impacts on the reliable operation of the BES.
- **Industry:** The Enterprise continues to collaborate with, and rely on, industry resources and expertise through the various standing committees[8], working groups and task forces which are critical to both identifying and supporting key initiatives and priorities.

2017 Key Business Planning Assumptions

As part of the annual business planning process, NERC and the Regional Entities developed a set of common business planning assumptions supporting the development their respective business plans and budgets. The Regional Entities used these assumptions to evaluate their projected workloads and determine resource levels and allocation required to complete necessary tasks and meet the obligations of their Regional Delegation Agreements. These common business planning assumptions are set forth in Exhibit A.

Application of Section 215 Criteria

In its order approving NERC's *2013 Business Plan and Budget*, FERC required NERC to establish criteria for determining whether its proposed activities are eligible for funding under Section 215. In an order dated April 19, 2013, FERC approved NERC's proposed criteria, with certain modifications.[9] Exhibit B summarizes the major activities NERC proposes to undertake in 2017 and the approved Section 215 criteria applicable to such activities.

[8] For further information please see the quarterly reports to the NERC Board of Trustees by the NERC Operating, Planning, Critical Information Protection, Standards and Compliance Certification Committees.

[9] North American Electric Reliability Corporation, Order on Compliance, 143 FERC ¶ 61,052 (2013).

Overview of 2017 Budget and Funding Requirements

NERC's 2017 combined expense and fixed asset (capital) budget is approximately $69.6M, which represents an increase of approximately $2.4M (3.6%) from the 2016 budget. Total expenses are increasing approximately $1.0M (1.5%) over 2016. The total fixed asset (capital) budget, excluding depreciation,[10] is approximately $4.4M, an increase of $461k over 2016. Approximately $8.3M (11.9%) of NERC's 2017 budget is related to CRISP. In the absence of CRISP, the 2017 budget would also increase $2.1M (3.5%) over 2016. As further explained in Section A – Electricity Information Sharing and Analysis Center (E-ISAC), the majority of the NERC CRISP budget will be funded by participating utilities, with only a small portion funded through assessments. A comparative statement of activities presenting NERC's 2017 budget with and without CRISP is set forth later in this section.

Without the release of funds from the Assessment Stabilization Reserve to offset assessments (as discussed below), NERC's total average assessments would increase $3.9M (6.8%) over 2016. One of the primary differences between NERC's current 2017 budget increase of 3.6% and the 6.8% 2017 assessment increase (unadjusted) results from eliminating the one-time application of 2016 penalty funds used to offset U.S. assessments in 2017. This loss of penalty offsets will not impact Canadian or Mexican assessments since U.S. penalty funds are only used to reduce U.S. assessments.[11] Other factors contributing to this difference include debt assumptions and projected reserve requirements, all of which impact assessments in the United States, Canada, and Mexico.

As a long-term strategy to stabilize assessments and align budget and assessment increases more closely, NERC has undertaken a multi-year strategy to manage assessment increases. Under the previous policy for releasing penalty funds, NERC was required to recognize those penalties in subsequent budget periods to offset assessment billings. In February 2015, NERC's Board approved an amendment to the company's Working Capital and Operating Reserve Policy. [12] Among the approved changes to this policy was the creation of an Assessment Stabilization Reserve.[13] This reserve was established to address the strategic goal of more closely aligning budget and assessment increases and provide resources to better manage year-to-year assessment increases. The eventual goal is to narrow the gap between annual percentage changes in NERC's budget and assessments that results from year-to-year changes in penalty collections.

Management proposes an overall average 2017 assessment increase of 4.9%, which includes the release of $1.1M from the Assessment Stabilization Reserves to offset U.S. assessments. The allocation of assessments to Canadian entities will depend on the final determination and allocation of certain compliance and enforcement costs to Canadian entities pursuant to NERC's policy on the allocation of compliance costs.[14]

[10] NERC and the Regional Entities budget Depreciation as an Operating Expense with an equal and offsetting credit against budgeted Fixed Asset Additions; as a result, the budgets do not include depreciation in the funding requirements.

[11] Accounting, Financial Statement and Budgetary Treatment of Penalties Imposed and Received for Violations of reliability standards, December 8, 2008 and as amended August 15, 2013

[12] NERC's Working Capital and Operating Reserve Policy. NERC filed a petition with FERC on March 6, 2015 for approval of this policy; the Commission conditionally approved the revised policy in an order issued June 18, 2015, in Docket No. RR15-8-000. *North American Electric Reliability Corporation, Order Conditionally Accepting Revisions to Working Capital and Operating Reserve Policy*, 151 FERC ¶ 61,225 (2015)

[13] In accordance with the approved policy, this reserve may be funded with penalty funds and surplus operating reserves. The actual amount of the contribution, as well as releases from the fund to reduce assessments, is determined annually as part of NERC's business plan and budget process, including the recommendation by the Board's Finance and Audit Committee and both Board and FERC approval.

[14] Expanded Policy on allocation of Certain Compliance and Enforcement Costs, July 29, 2008.

The following table provides a high-level year-over-year comparison of the major categories of expenses, total budget, and FTEs.

Statement of Activities and Fixed Assets Expenditures 2016 and 2017 Budgets
STATUTORY

	2016 Budget	2016 Projection	Projection v 2016 Budget Over(Under)	2017 Budget	2017 Budget v 2016 Budget Over (Under)	% Over (Under)
Funding						
NERC Assessments	$ 57,081,445	$ 57,081,445	$ (0)	$ 59,856,314	$ 2,774,868	4.9%
Penalty Sanctions	1,439,000	1,439,000	-	1,100,000	(339,000)	
Third-Party Funding (CRISP)	6,830,738	7,335,757	505,019	6,990,447	159,709	
Testing Fees	1,867,972	1,867,972	-	1,921,900	53,928	
Services & Software	50,000	50,000	-	50,000	-	
Workshops	230,000	269,201	39,201	230,000	-	
Interest	3,000	35,898	32,898	3,000	-	
Total Funding (A)	**$ 67,502,155**	**$ 68,079,475**	**$ 577,320**	**$ 70,151,660**	**$ 2,649,505**	**3.9%**
Expenses						
Personnel Expenses	$ 37,283,807	$ 37,288,967	$ 5,161	$ 38,641,331	$ 1,357,525	3.6%
Meeting Expenses	3,620,286	3,646,564	26,278	3,372,886	(247,400)	-6.8%
Operating Expenses	24,903,515	25,947,939	1,044,424	24,800,690	(102,825)	-0.4%
Other Non-Operating Expenses	110,000	100,668	(9,332)	106,725	(3,275)	-3.0%
Total Expenses	**$ 65,917,608**	**$ 66,984,139**	**$ 1,066,531**	**$ 66,921,632**	**$ 1,004,024**	**1.5%**
Fixed Assets						
Depreciation	$ (2,641,943)	$ (2,558,606)	$ 83,336	$ (1,691,457)	$ 950,486	
Computer & Software CapEx	2,447,000	2,362,402	(84,598)	2,572,000	125,000	
Equipment CapEx	1,464,000	1,545,797	81,797	1,800,000	336,000	
Inc(Dec) in Fixed Assets	**1,269,057**	**1,349,593**	**80,535**	**2,680,543**	**1,411,486**	
TOTAL BUDGET	**$ 67,186,665**	**$ 68,333,732**	**$ 1,147,067**	**$ 69,602,175**	**$ 2,415,510**	**3.6%**
FTEs	**192.5**	**188.6**	**(3.9)**	**189.9**	**(2.6)**	**-1.3%**

NERC's 2017 budget and funding requirements reflect the resources necessary to support achievement of the goals and objectives set forth in the Strategic Plan. The 2017 budget is comprised of both operating and capital (fixed asset) costs. Operating costs generally include personnel, consulting, office space, software licensing, third-party data management, and communications and other customary services to support office operations. Fixed asset (capital) costs primarily reflect investments in equipment and software to support operations, including investments in the development of software applications and infrastructure to facilitate improved business processes and efficiency.

Key Budget Assumptions

Key assumptions used in the development of NERC's 2017 budget include the following:

- Maintaining FTEs at a similar level as 2016. Management routinely reviews resource allocation to ensure that the appropriate amount and type of resources are being dedicated to key priorities and activities. As operations in some areas become more efficient and/or major initiatives are completed, resources are redeployed to priority areas. For example, as work on reliability standards reduced as regulatory obligations were addressed, it was possible to reallocate some of those resources to support additional compliance assurance, reliability risk assessment, and security needs without increasing the company's overall FTE budget.
- Applying a 6.0% reduction to FTEs (vacancy rate) to account for attrition and hiring delays. This assumption is based on a review and analysis of historic attrition and vacancy rates, as well as the time it takes to recruit and onboard new staff. This is reduction in the historical vacancy rate

assumptions and reflects the ongoing management focus on recruiting and retaining appropriate resources.

- Market-based compensation for personnel. Executive and staff compensation and benefits are established based on guidelines established by NERC's Corporate Governance and Human Resources Committee and comprehensive market compensation and benefit information provided by a leading nationally recognized compensation and benefits consulting firm, as well as other available data. An updated market study was completed in late 2015 under the oversight of NERC's Corporate Governance and Human Resources Committee.
- Anticipating market increases in medical and dental benefit plan costs. Medical and dental premium cost estimates are based on market data provided by the company's benefits consultant. Current 2017 budget estimates are in the upper end of the range provided by NERC's benefits consultant. This estimate will continue to be evaluated prior to finalization of the final recommended 2017 budget. No other changes to retirement or other benefit plans have been assumed for 2017.
- In 2015, the Electricity Subsector Coordinating Council (ESCC)[15] presented its recommendations resulting from a review of the E-ISAC operations performed that year. These recommendations included a request to evaluate and potentially enhance the user interface and underlying functionality of the E-ISAC portal. In 2015, the ESCC established a Member Executive Committee (MEC) to provide guidance with respect to various E-ISAC matters, including improvements to the E-ISAC portal. As part of an approved 2016 work plan, the E-ISAC staff worked closely with the MEC to develop a business case and funding estimates for these improvements. A power point presentation summarizing the business case, funding estimate and additional detail regarding the portal improvement project is attached as Exhibit F.

  The 2017 E-ISAC budget includes $1M for the portal enhancements ($250,000 of which is allocated to CRISP) for the portal project. The annual impact of the proposed $1M investment on assessments will be approximately $250,000 since projects of this nature are typically financed through NERC's capital financing program and funded over a three year period. The MEC has provided written comments [found here] in support of this investment.
- Meeting and travel expenses are being held flat based on a review of 2015 and 2016 costs. The company has undertaken a number of significant efforts over the past several years to reduce travel and meeting expenses. For example, the company has also worked closely with Regional Entities to share meeting space where possible, which has helped reduce meeting costs.
- Contractor and consulting expenses are developed on a department-by-department basis and reflect both known and anticipated expenses, based on historic and current information.

[15] The Electricity Subsector Coordinating Council (ESCC) serves as the principal liaison between the federal government and the electric power sector, with the mission of coordinating efforts to prepare for, and respond to, national-level disasters or threats to critical infrastructure. The ESCC includes utility CEOs and trade association leaders representing all segments of the industry. Its counterparts include senior Administration officials from the White House, relevant Cabinet agencies, federal law enforcement, and national security organizations.

The following table summarizes total year-over-year contractor and consulting costs by department.

Consultants & Contracts	2016 BUDGET	2017 BUDGET	2017 vs 2016 Budget
Compliance Assurance	200,000	50,000	(150,000)
Event Analysis	56,000	-	(56,000)
Compliance Investigation, Registration and Certification	50,000	-	(50,000)
Reliability Assessments and System Analysis	575,000	525,000	(50,000)
Performance Analysis	509,039	528,082	19,044
Situation Awareness	1,211,475	1,295,850	84,375
E-ISAC	748,335	899,835	151,500
CRISP	5,888,594	5,888,594	-
System Operator Certification	327,600	219,800	(107,800)
Continuing Education, Training & Education	348,200	360,800	12,600
General & Administrative	95,000	15,000	(80,000)
Information Technology	2,094,671	2,312,787	218,116
Human Resources	550,000	575,000	25,000
Finance and Accounting	297,000	457,000	160,000
TOTAL CONSULTANTS AND CONTRACTS	**12,950,914**	**13,127,749**	**176,835**

The Compliance Assurance department will require ongoing, though significantly reduced, consulting support for implementation of compliance assurance reform initiatives. Contract and consulting expenses for the Reliability Assessment, Performance Analysis, and System Analysis are largely for software and services supporting reliability data management and analysis. Situation Awareness costs are primarily related to licenses and services supporting Situation Awareness for FERC, NERC, and the Regional Entities (SAFNR), and other reliability information and notification (e.g., alerts) systems.

E-ISAC consulting costs for 2017 include support for GridEx and analytical tools. Approximately $6M of the total E-ISAC contract and consulting costs are CRISP related and funded by CRISP participants.

Training, Education, and Operator Certification contract and consulting costs include the cost of operator certification, training, and continuing education programs, and training NERC personnel. It also includes supporting compliance and enforcement (risk-based CMEP) and other training initiatives.

Information Technology (IT) contract and consulting support is primarily for systems and software maintenance and support services, including costs for enhancements to and maintenance of enterprise applications. Costs associated with IT security programs and the ongoing implementation and support of a document management program are also included. Software development costs are primarily budgeted under fixed (capital) assets and are discussed further below.

Human Resources contract and consulting costs are primarily for employee training, various surveys, compensation studies, and consulting services to support improvements in human resource information systems.

Finance and Accounting costs are primarily for audit and consulting services to support the Enterprise Risk Management and Internal Control audit plan and Compliance and Certification Committee (CCC) audit plan, as well as consulting services to implement new financial reporting tools and review insurance strategy and solutions.

Fixed Asset (Capital) Budget and Capital Financing

NERC's 2017 capital budget is approximately $4.4M (excluding depreciation), which represents an increase of approximately $461k from 2016. The table below provides a summary of the major capital budget components.

NERC CAPITAL BUDGET	2016	2017
ERO Application Development	$ 1,500,000	$ 700,000
E-ISAC Portal Development		1,000,000
Document Management	465,000	335,000
Hardware (Storage, servers, laptops)	955,000	991,000
Other Equipment	535,000	885,000
Disaster Recovery	200,000	150,000
NERC Software licenses	256,000	311,000
Total Capital Budget	**$ 3,911,000**	**$ 4,372,000**

NERC has budgeted $2.2M (both operating and capital expenses) in 2017 for services related to the planning, design, and implementation of software applications supporting the development of enterprise tools for common NERC and Regional Entity operations. These ERO Enterprise related costs include $700k in capital expenditures and $1.5M in other IT operating costs. Senior management from both NERC and the Regional Entities refined and updated the ERO Enterprise's long-term IT architecture and data management plans and the specific applications that will be under development in 2017. The IT department section offers further detail regarding updates to the Enterprise IT Strategy; the current status of the development of Enterprise IT applications; and projects that will be under development in 2017. Information regarding the cost and benefits of each project are also provided. The proposed $2.2M budget for 2017 related to enterprise application development and support is less than the 2017 projection presented in NERC's *2016 Business Plan and Budget* due largely to the decision to delay the development of a replacement for the current compliance monitoring and enforcement tracking system to 2018. Further information regarding the ERO Enterprise application development plan and budget is contained in Section A – Information Technology department. NERC's 2017 capital budget also includes ongoing funding for IT security, disaster recovery, data storage, replacement of servers and laptops, and software license costs.

The 2017 budget projection assumes that approximately $1.5M of the total $4.4M capital budget will be financed through the capital financing program that was described and put in place as part of NERC's *2014 Business Plan and Budget*. Further information regarding capital financing may be found in Exhibit D.

Working Capital and Operating Reserves

Management is proposing an overall reserve budget of $7.8M for the combined four categories of operating reserves and the Assessment Stabilization Reserve under the company's Working Capital and Operating Reserve Policy. This represents a decrease of $1.1M (11.9%) from the total reserve amounts included in NERC's approved 2016 budget. While individual categories reflect increases and decreases resulting from operating needs and uses, the budget does not reflect additional working capital requirements in total. Pursuant to the company's Working Capital and Operating Reserve policy, funds reserved for future liabilities are now budgeted under a separate reserve category entitled Future Obligation Reserve. This reserve is primarily comprised of existing funds and is budgeted to be $2.6M for 2017. The second category of operating reserves is the System Operating Certification Reserve. The 2017 System Operator Certification Reserve is budgeted at $714k and comprised of existing funds. The third category of operating reserves is the CRISP Operating Reserve, which represents funds dedicated to support CRISP. Similar to 2016, these reserves are established pursuant to a CRISP budget agreed to and funded entirely by utilities participating in CRISP. These reserves have no impact on assessments and they are segregated from other reserves pursuant to the terms of the CRISP agreements. Currently, the CRISP reserves are projected to be $500k in the 2017 budget.

The fourth category of operating reserves is the Operating Contingency Reserve. This reserve includes funds for expenditures that were not anticipated at the time the company's budget was prepared or for which the timing was uncertain. NERC's current policy on Operating Contingency Reserves requires a reserve target of 3.5–7.0%, except as otherwise approved by the Board after review and recommendation by the NERC Finance and Audit Committee. This percentage is calculated against NERC's total budget for operating and capital expenditures, less those costs related to CRISP and System Operator Certification (both having separate reserve categories). For this draft of the 2017 budget, management is recommending an Operating Contingency Reserve of approximately $2.2M, or 3.7% of total operating and capital costs, excluding CRISP and System Operator costs, which is slightly less than the minimum recommended in the policy but within the discretion of the NERC Board of Trustees to approve, upon review and recommendation of NERC's Finance and Audit Committee.

In addition to the four categories of operating reserves and as previously discussed, the company's amended Working Capital and Operating Reserve Policy also provides for an Assessment Stabilization Reserve. To date, this reserve has been funded entirely by previously received penalties and is projected to have a balance of $2.7M as of January 1, 2017, pending approval by the NERC Board. For purposes of the company's *2017 Business Plan and Budget*, management proposes the release of $1.1M in Assessment Stabilization Reserve funds to offset assessments. The use of $1.1M to offset assessments in 2017 yields an average increase of 4.9% over the 2016 assessments. The balance of $1.7M will be used to reduce assessments in a future period, subject to review and approval of the applicable year business plan and budget. A further discussion of the use of this remaining Assessment Stabilization Reserve balance may be found below in the section entitled 2018-2019 Projections.

Department Budget and FTE Comparisons

The following tables set forth a 2016–2017 total budget comparison by department. The amounts shown below reflect all direct and indirect departmental costs, including fixed asset costs. Costs incurred for general and administrative and other overheads are considered indirect, and are allocated to the statutory departments based on the ratio of that department's budgeted FTEs to total budgeted FTEs.

2016–2017 Total Budget by Department

Total Budget	Budget 2016	Budget 2017	Change 2017 Budget v 2016 Budget	% Change
Reliability Standards	8,193,116	8,100,282	(92,834)	-1.1%
Compliance Analysis, Certificaton and Registration	4,632,871	3,646,289	(986,582)	-21.3%
Compliance Assurance	9,420,903	7,858,599	(1,562,305)	-16.6%
Compliance Enforcement	5,293,298	5,800,647	507,349	9.6%
Reliability Assessments and Performance Analysis	9,918,728	12,444,449	2,525,721	25.5%
Training, Education and Operator Certification	3,912,231	3,757,501	(154,731)	-4.0%
Reliability Risk Management				
Event Analysis	5,355,795	5,446,206	90,411	1.7%
Situation Awareness	3,692,197	4,032,862	340,664	9.2%
E-ISAC	16,767,525	18,515,341	1,747,816	10.4%
Total Budget	67,186,665	69,602,175	2,415,510	3.6%
Total Funding	67,502,155	70,151,660	2,649,505	3.9%
Change in Working Capital	315,490	549,485	233,995	0.3%

The decreases in Compliance Analysis, Certification and Registration, and Compliance Assurance departments costs are primarily due to the transfer of resources from these departments as part of the internal reorganization to better align resources to support strategic goals and risk priorities. The increase in the Reliability Assessment and Performance Analysis program area and Event Analysis department budget are due to the reallocation of resources to that department to further support increased reliability risk assessment and analysis resource priorities. The increase in the Situation Awareness department is primarily due to enhancement or modification of reliability-related situation awareness and monitoring tools. The increase in the E-ISAC department is primarily due to planned enhancements to the E-ISAC portal and 2017 GridEx.

The following table presents a year-over-year comparison of FTEs by department and reflects 2016 personnel additions, interdepartmental transfers, and attrition assumptions. An FTE represents the number of employees employed full time during the year, plus the number of employees employed part time (less than full schedule) or during a portion of the year converted to a full-time basis. Headcount represents the total number of personnel employed during the year, regardless of the length of their employment during that year. FTEs will be less than headcount, unless there are no part-time employees or employees who are employed less than a full year. The company's 2017 personnel budget is based upon existing headcount and associated compensation and benefit costs, as well as assumptions on the number and cost of new hires, all within an overall FTE budget. An average vacancy rate is applied to each position and its associated costs to arrive at an overall personnel cost budget. The vacancy rate represents an adjustment, which is applied in the calculation of budgeted personnel costs to account for attrition and variations in the budget assumptions on the timing of new hires.

2016–2017 Year-Over-Year Comparison of FTEs by Department

Total FTE's by Program Area	Budget 2016	Budget 2017	Change from 2016 Budget
STATUTORY			
Operational Programs			
Reliability Standards	17.98	17.16	(0.8)
Compliance Analysis, Certification and Registration	10.14	7.52	(2.6)
Compliance Assurance	19.36	15.51	(3.9)
Compliance Enforcement	12.22	13.16	0.9
Reliability Assessments and Performance Analysis	18.67	23.50	4.8
Training, Education and Operator Certification	7.38	7.05	(0.3)
Event Analysis	11.06	11.28	0.2
Situation Awareness	5.53	5.64	0.1
E-ISAC	18.90	19.74	0.8
Total FTEs Operational Programs	**121.24**	**120.56**	**(0.7)**
Administrative Programs			
General & Administrative	17.52	16.92	(0.6)
Legal and Regulatory	12.22	11.28	(0.9)
Information Technology	22.13	23.27	1.1
Human Resources	2.77	2.82	0.0
Finance and Accounting	16.60	15.04	(1.6)
Total FTEs Administrative Programs	**71.23**	**69.33**	**(1.9)**
Total FTEs	**192.47**	**189.88**	**(2.5)**

*Reflects 2017 additions and transfers between departments, anticipated timing of 2017 hires, and assumes 6% attrition in all programs

Total FTEs in the Administrative Programs is decreasing 2.7%, reflecting reallocation of resources among the various departments The increase in Information Technology FTEs is due to the reallocation of personnel to strengthen project management oversight over NERC and ERO Enterprise software application development and implementation.

The NERC 2017 organizational chart can be found in Appendix 1**.** The difference between the number of positions reflected in the 2017 organizational chart and total 2017 budgeted FTEs is due to assumptions regarding vacancy rates and timing of new hires.

The following pages include a statement of activities comparing the 2016 budget and the proposed 2017 budget, followed by a statement of activities comparing the 2016 budget and the proposed 2017 budget with and without CRISP.

Statement of Activities and Fixed Assets Expenditures 2016 and 2017 Budgets

STATUTORY

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	% Inc 2017 over 2016	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding								
ERO Funding								
NERC Assessments	$ 57,081,445	$ 57,081,445	$ (0)	$ 59,856,314	$ 2,774,868	**4.9%**	$ 59,652,362	$ 203,952
Penalty Sanctions	1,439,000	1,439,000	-	1,100,000	(339,000)		1,100,000	-
Total NERC Funding	**$ 58,520,445**	**$ 58,520,445**	**$ (0)**	**$ 60,956,314**	**$ 2,435,868**		**$ 60,752,362**	**$ 203,952**
Third-Party Funding (CRISP)	6,830,738	7,335,757	505,019	6,990,447	159,709		6,910,701	79,746
Testing Fees	1,867,972	1,867,972	-	1,921,900	53,928		1,921,900	-
Services & Software	50,000	50,000	-	50,000	-		50,000	-
Workshops	230,000	269,201	39,201	230,000	-		230,000	-
Interest	3,000	35,898	32,898	3,000	-		3,000	-
Miscellaneous	-	202	202	-	-		-	-
Total Funding (A)	**$ 67,502,155**	**$ 68,079,475**	**$ 577,320**	**$ 70,151,660**	**$ 2,649,505**	**3.9%**	**$ 69,867,962**	**$ 283,698**
Expenses								
Personnel Expenses								
Salaries	$ 28,842,336	$ 29,052,918	$ 210,581	$ 30,073,438	$ 1,231,102		$ 29,979,980	93,458
Payroll Taxes	1,871,367	1,830,724	(40,643)	$ 1,847,130	(24,237)		1,908,285	(61,154)
Benefits	3,579,280	3,390,190	(189,090)	$ 3,643,806	64,526		3,668,103	(24,297)
Retirement Costs	2,990,823	3,015,135	24,312	$ 3,076,956	86,134		3,127,490	(50,533)
Total Personnel Expenses	**$ 37,283,807**	**$ 37,288,967**	**$ 5,161**	**$ 38,641,331**	**$ 1,357,525**	**3.6%**	**$ 38,683,857**	**(42,526)**
Meeting Expenses								
Meetings	$ 1,096,500	$ 1,194,500	$ 98,000	$ 1,071,500	$ (25,000)		$ 1,071,500	-
Travel	2,203,786	2,190,184	(13,602)	2,203,786	(0)		2,203,786	-
Conference Calls	320,000	261,880	(58,120)	97,600	(222,400)		97,600	-
Total Meeting Expenses	**$ 3,620,286**	**$ 3,646,564**	**$ 26,278**	**$ 3,372,886**	**$ (247,400)**	**-6.8%**	**$ 3,372,886**	**-**
Operating Expenses								
Consultants & Contracts	$ 12,865,914	$ 13,972,958	$ 1,107,044	$ 13,127,749	$ 261,835		$ 13,285,749	(158,000)
Office Rent	3,054,287	3,224,287	170,000	3,117,009	62,722		3,117,009	-
Office Costs	3,795,572	3,740,288	(55,284)	4,359,340	563,768		4,280,607	78,733
Professional Services	2,509,300	2,414,300	(95,000)	2,468,135	(41,165)		2,468,135	-
Miscellaneous	36,500	37,500	1,000	37,000	500		37,000	-
Depreciation	2,641,943	2,558,606	(83,336)	1,691,457	(950,486)		1,691,457	-
Total Operating Expenses	**$ 24,903,515**	**$ 25,947,939**	**$ 1,044,424**	**$ 24,800,690**	**$ (102,825)**	**-0.4%**	**$ 24,879,956**	**$ (79,267)**
Total Direct Expenses	**$ 65,807,608**	**$ 66,883,471**	**$ 1,075,863**	**$ 66,814,907**	**$ 1,007,299**	**1.5%**	**$ 66,936,699**	**$ (121,792)**
Indirect Expenses	**$ -**	**$ 0**	**$ 0**	**$ 0**	**$ 0**		**$ -**	**$ 0**
Other Non-Operating Expenses	**$ 110,000**	**$ 100,668**	**$ (9,332)**	**$ 106,725**	**$ (3,275)**	**-3.0%**	**$ 122,100**	**$ (15,375)**
Total Expenses (B)	**$ 65,917,608**	**$ 66,984,139**	**$ 1,066,531**	**$ 66,921,632**	**$ 1,004,024**	**1.5%**	**$ 67,058,799**	**$ (137,167)**
Change in Assets	**$ 1,584,548**	**$ 1,095,336**	**$ (489,211)**	**$ 3,230,028**	**$ 1,645,481**		**$ 2,809,163**	**420,865**
Fixed Assets								
Depreciation	$ (2,641,943)	$ (2,558,606)	83,336	$ (1,691,457)	$ 950,486		$ (1,691,457)	$ -
Computer & Software CapEx	2,447,000	2,362,402	(84,598)	2,572,000	125,000	**10.5%**	1,672,000	900,000
Furniture & Fixtures CapEx	-	-	-	-	-		-	-
Equipment CapEx	1,464,000	1,545,797	81,797	1,800,000	336,000		1,800,000	-
Leasehold Improvements	-	-	-	-	-		-	-
Allocation of Fixed Assets	**$ (0)**	$ (0)	$ 0	$ 0	$ 0		**$ -**	**$ 0**
Inc(Dec) in Fixed Assets (C)	**1,269,057**	**1,349,593**	**80,535**	**2,680,543**	**1,411,486**		**1,780,543**	**900,000**
TOTAL BUDGET (=B + C)	**$ 67,186,665**	**$ 68,333,732**	**$ 1,147,067**	**$ 69,602,175**	**$ 2,415,510**	**3.6%**	**$ 68,839,343**	**$ 762,833**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)[1]	**$ 315,490**	**$ (254,257)**	**$ (569,747)**	**$ 549,485**	**$ (716,491)**		**$ 1,028,620**	**$ (479,135)**
FTEs	**192.5**	**188.6**	**(3.9)**	**189.88**	**(2.6)**	**-1.3%**	**193.11**	**(3.23)**

[1]The budgeted change in working capital reflects both a reduction in excess working capital and operating reserves and the assumptions related to capital financing. Refer to Table B-1 on page 81 for a complete analysis of the Working Capital and Operating Reserve balance.

Statement of Activities and Fixed Assets Expenditures 2016 and 2017 Budgets

STATUTORY

	2016 Budget	2016 CRISP Budget	2016 Budget w/out CRISP	2017 Budget	2017 CRISP Budget	2017 Budget w/out CRISP	Variance 2017 Budget v 2016 Budget Over(Under)	% Inc 2017 over 2016
Funding								
ERO Funding								
NERC Assessments	$ 57,081,445	$ 1,108,641	$ 55,972,805	$ 59,856,314	$ 1,275,681	$ 58,580,633	$ 2,607,828	**4.7%**
Penalty Sanctions	1,439,000	33,572	$ 1,405,428	1,100,000	26,243	1,073,757	(331,671)	
Total NERC Funding	**$ 58,520,445**	**$ 1,142,213**	**$ 57,378,232**	**$ 60,956,314**	**$ 1,301,923**	**$ 59,654,390**	**$ 2,276,158**	
Third-Party Funding (CRISP)	6,830,738	6,830,738	$ -	6,990,447	6,990,447	$ -	-	
Testing Fees	1,867,972	-	$ 1,867,972	1,921,900	-	$ 1,921,900	53,928	
Services & Software	50,000	-	$ 50,000	50,000	-	$ 50,000	-	
Workshops	230,000	-	$ 230,000	230,000	-	$ 230,000	-	
Interest	3,000	68	$ 2,932	3,000	70	$ 2,930	(2)	
Miscellaneous	-	-	$ -	-	-	$ -	-	
Total Funding (A)	**$ 67,502,155**	**$ 7,973,019**	**$ 59,529,136**	**$ 70,151,660**	**$ 8,292,440**	**$ 61,859,220**	**$ 2,330,084**	**3.9%**
Expenses								
Personnel Expenses								
Salaries	$ 28,842,336	$ 592,724	$ 28,249,612	$ 30,073,438	$ 603,432	$ 29,470,007	$ 1,220,394	
Payroll Taxes	1,871,367	32,899	$ 1,838,469	1,847,130	32,329	$ 1,814,801	(23,668)	
Benefits	3,579,280	50,247	$ 3,529,034	3,643,806	68,375	$ 3,575,431	46,398	
Retirement Costs	2,990,823	65,802	$ 2,925,021	3,076,956	64,236	$ 3,012,721	87,700	
Total Personnel Expenses	**$ 37,283,807**	**$ 741,671**	**$ 36,542,135**	**$ 38,641,331**	**$ 768,371**	**$ 37,872,960**	**$ 1,330,825**	**3.6%**
Meeting Expenses								
Meetings	$ 1,096,500	$ 30,000	$ 1,066,500	$ 1,071,500	$ 30,000	$ 1,041,500	$ (25,000)	
Travel	2,203,786	37,455	$ 2,166,331	2,203,786	37,455	$ 2,166,331	(0)	
Conference Calls	320,000	2,000	$ 318,000	97,600	2,237	$ 95,363	(222,637)	
Total Meeting Expenses	**$ 3,620,286**	**$ 69,455**	**$ 3,550,831**	**$ 3,372,886**	**$ 69,692**	**$ 3,303,194**	**$ (247,637)**	**-7.0%**
Operating Expenses								
Consultants & Contracts	$ 12,865,914	$ 5,888,594	$ 6,977,320	$ 13,127,749	$ 5,888,594	$ 7,239,155	$ 261,835	
Office Rent	3,054,287	-	$ 3,054,287	3,117,009	-	$ 3,117,009	62,722	
Office Costs	3,795,572	304,027	$ 3,491,545	4,359,340	305,683	$ 4,053,657	562,112	
Professional Services	2,509,300	175,000	$ 2,334,300	2,468,135	175,000	$ 2,293,135	(41,165)	
Miscellaneous	36,500	250	$ 36,250	37,000	250	$ 36,750	500	
Depreciation	2,641,943	-	$ 2,641,943	1,691,457	5,297	$ 1,686,159	(955,783)	
Total Operating Expenses	**$ 24,903,515**	**$ 6,367,871**	**$ 18,535,644**	**$ 24,800,690**	**$ 6,374,824**	**$ 18,425,865**	**$ (109,779)**	**-0.6%**
Total Direct Expenses	**$ 65,807,608**	**$ 7,178,997**	**$ 58,628,611**	**$ 66,814,907**	**$ 7,212,888**	**$ 59,602,019**	**$ 973,409**	**1.7%**
Indirect Expenses	**$ -**	**$ 650,361**	**$ (650,361)**	**$ 0**	**$ 687,169**	**$ (687,169)**	**$ (36,809)**	
Other Non-Operating Expenses	**$ 110,000**	**$ -**	**$ 110,000**	**$ 106,725**	**$ -**	**$ 106,725**	**$ (3,275)**	**-3.0%**
Total Expenses (B)	**$ 65,917,608**	**$ 7,829,358**	**$ 58,088,250**	**$ 66,921,632**	**$ 7,900,057**	**$ 59,021,575**	**$ 933,325**	**1.6%**
Change in Assets	**$ 1,584,548**	**$ 143,662**	**$ 1,440,886**	**$ 3,230,028**	**$ 392,383**	**$ 2,837,645**	**$ 1,396,759**	
Fixed Assets								
Depreciation	$ (2,641,943)	$ -	$ (2,641,943)	$ (1,691,457)	$ (5,297)	$ (1,686,159)	$ 955,783	
Computer & Software CapEx	2,447,000	100,000	2,347,000	2,572,000	350,000	2,222,000	(125,000)	
Furniture & Fixtures CapEx	-	-	-	-	-	-	-	
Equipment CapEx	1,464,000	-	1,464,000	1,800,000	-	1,800,000	336,000	
Leasehold Improvements	-	-	-	-	-	-	-	
Allocation of Fixed Assets	**$ (0)**	$ 43,105	$ (43,105)	$ 0	$ 47,681	$ (47,681)	$ (4,575)	
Inc(Dec) in Fixed Assets (C)	**1,269,057**	**143,105**	**1,125,952**	**2,680,543**	**392,383**	**2,288,160**	**1,162,208**	**103.2%**
TOTAL BUDGET (=B + C)	**$ 67,186,665**	**$ 7,972,463**	**$ 59,214,202**	**$ 69,602,175**	**$ 8,292,440**	**$ 61,309,735**	**$ 2,095,533**	**3.5%**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)[1]	**$ 315,490**	**$ 556**	**$ 314,934**	**$ 549,485**	**$ -**	**$ 549,485**	**$ 234,551**	
FTEs	**192.47**	**2.8**	**189.71**	**189.88**	**2.8**	**187.06**	**(2.6)**	**-1.4%**

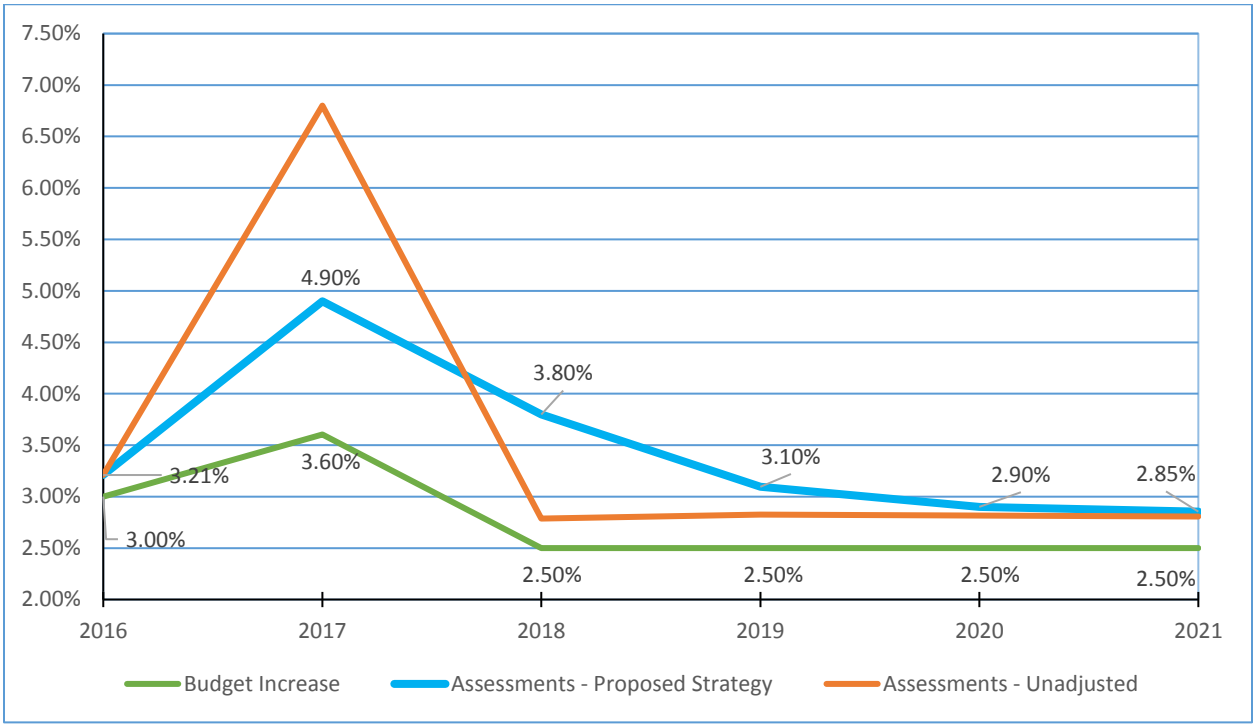
Projections for 2018–2019

Management has developed preliminary operating and fixed asset (capital) projections for 2018 and 2019. The significant assumptions considered in preparing these projections include:

- No increases in total FTEs over the 2017 budget
- Personnel and benefit cost increases are consistent with the 2017 budget assumptions
- Operating costs, including contractor and consulting expenses, are slightly higher due to increases in contract costs for rent, maintenance costs associated with software applications supporting ERO Enterprise Operations, and ongoing implementation of improved budgeting and financial reporting tools.
- Debt service repayment obligations in connection with the company's Capital Financing Program consistent with the projected Enterprise IT Applications capital forecast
- No increase in CRISP-related expenditures, except for personnel and benefit cost increases as noted above

Assessments are projected to increase by gradually declining percentages during the next three years as NERC implements a stabilization strategy. The goal of this strategy is to align budgeted costs and assessment increases more closely so that the unanticipated receipt of penalties will not cause large variances in future assessment projections. Currently, NERC projects assessments to increase 4.5% in 2017, 3.8% in 2018, and 3.1% in 2019 with declining releases each year from the Assessment Stabilization Reserve to meet these targets. A summary of these projections and reserve releases are shown in the table below. A budget increase of 2.5% was used for modeling purposes and is subject to change. The assessment strategy is also depicted in the graph below, showing the assumed budget increases, unadjusted assessment increases, and implementation of the assessment strategy.

	Budget	Assessment	----- Assessment Stabilization Reserve -----		
Year	Increase	Increase	Additions	Uses	Balance
2016	3.00%	3.21%	$ 3,710,000	$ (1,439,000)	$ 2,271,000
2017	3.60%	4.90%	1,000,000	(1,100,000)	2,171,000
2018	2.50%	3.80%	-	(410,000)	1,761,000
2019	2.50%	3.10%	-	(270,000)	1,491,000



The model does not assume any penalties beyond those we currently expect in 2016 and 2017 and includes $500k in penalty funds which NERC is scheduled receive in 2017 under the terms of an existing settlement agreement will be contributed to the Assessment Stabilization Reserve. While both the unexpected receipt of additional penalties and the current balance could yield a sizable amount of funds, future unexpected budget increases, ERO system development projects, or other one-time costs may be appropriate uses of these funds in order to stabilize assessments in the future.[16]

[16] In determining the amount of the Assessment Stabilization Reserve that is released each year, the company's Working Capital and Operating Reserve Policy requires that the NERC Finance and Audit Committee and Board review a three-year forecast of assessments, as well as the availability of funding for this reserve from surplus funds and penalty funds. The actual contributions and releases from the Assessment Stabilization Reserve in any year must be approved as part of NERC's annual business plan and budget process, with opportunity for review and input by stakeholders.

Statement of Activities and Fixed Assets Expenditures
2017 Budget & Projected 2018 and 2019 Budgets

	2017 Budget	2018 Projection	$ Change 18 v 17	% Change 18 v 17	2019 Projection	$ Change 19 v 18	% Change 19 v 18
Funding							
ERO Funding							
NERC Assessments	$ 59,856,314	$ 62,143,946	$ 2,287,633	3.8%	$ 64,088,553	$ 1,944,607	3.1%
Penalty Sanctions	1,100,000	410,000	(690,000)	-62.7%	-	(410,000)	-100.0%
Total NERC Funding	**$ 60,956,314**	**$ 62,553,946**	**$ 1,597,633**	**2.6%**	**$ 64,088,553**	**$ 1,534,607**	**2.5%**
Third-Party Funding (CRISP)	6,990,447	6,990,447	-	0.00%	6,990,447	-	0.0%
Testing Fees	1,921,900	1,921,900	-	0.00%	1,921,900	-	0.0%
Services & Software	50,000	50,000	-	0.00%	50,000	-	0.0%
Workshops	230,000	230,000	-	0.00%	230,000	-	0.0%
Interest	3,000	3,000	-	0.00%	3,000	-	0.0%
Miscellaneous	-		-			-	
Total Funding (A)	**$ 70,151,660**	**$ 71,749,293**	**$ 1,597,633**	**2.3%**	**$ 73,283,900**	**$ 1,534,607**	**2.1%**
Expenses							
Personnel Expenses							
Salaries	$ 30,073,438	$ 31,035,788	$ 962,350	3.2%	$ 31,966,862	$ 931,074	3.0%
Payroll Taxes	1,847,130	1,869,296	22,166	1.2%	1,893,597	24,301	1.3%
Benefits	3,643,806	3,887,941	244,135	6.7%	4,152,321	264,380	6.8%
Retirement Costs	3,076,956	3,141,573	64,616	2.1%	3,264,094	122,521	3.9%
Total Personnel Expenses	**$ 38,641,331**	**$ 39,934,598**	**$ 1,293,267**	**3.3%**	**$ 41,276,874**	**$ 1,342,276**	**3.4%**
Meeting Expenses							
Meetings	$ 1,071,500	$ 1,081,500	$ 10,000	0.9%	$ 1,071,500	(10,000)	-0.9%
Travel	2,203,786	2,203,786	-	0.0%	2,203,786	-	0.0%
Conference Calls	97,600	97,600	-	0.0%	97,600	-	0.0%
Total Meeting Expenses	**$ 3,372,886**	**$ 3,382,886**	**$ 10,000**	**0.3%**	**$ 3,372,886**	**$ (10,000)**	**-0.3%**
Operating Expenses							
Consultants & Contracts	$ 13,127,749	13,595,592	467,844	3.6%	14,367,077	771,485	5.7%
Office Rent	3,117,009	3,099,048	(17,961)	-0.6%	3,104,557	5,509	0.2%
Office Costs	4,359,340	4,359,340	-	0.0%	4,359,340	-	0.0%
Professional Services	2,468,135	2,652,075	183,940	7.5%	2,661,992	9,917	0.4%
Miscellaneous	37,000	37,000	-	0.0%	37,000	-	0.0%
Depreciation	1,691,457	1,194,345	(497,112)	-29.4%	932,549	(261,796)	-21.9%
Total Operating Expenses	**$ 24,800,690**	**$ 24,937,400**	**$ 136,711**	**0.6%**	**$ 25,462,516**	**$ 525,116**	**2.1%**
Total Direct Expenses	**$ 66,814,907**	**$ 68,254,885**	**$ 1,439,978**	**2.2%**	**$ 70,112,277**	**$ 1,857,392**	**2.7%**
Indirect Expenses	**$ -**	**$ -**			**$ -**	**$ -**	
Other Non-Operating Expenses	**$ 106,725**	**$ 114,000**	**$ 7,275**	**6.8%**	**116,000**	**2,000**	**1.8%**
Total Expenses (B)	**$ 66,921,632**	**$ 68,368,885**	**$ 1,447,253**	**2.2%**	**$ 70,228,277**	**1,859,392**	**2.7%**
Change in Assets	**$ 3,230,028**	**$ 3,380,408**	**$ 150,380**	**4.7%**	**$ 3,055,623**	**$ (324,785)**	**-9.6%**
Fixed Assets					-		
Depreciation	$ (1,691,457)	$ (1,194,345)	$ 497,112	-29.4%	$ (932,549)	$ 261,796	-21.9%
Computer & Software CapEx	2,572,000	2,562,000	(10,000)	-0.4%	2,112,000	(450,000)	-17.6%
Furniture & Fixtures CapEx	-	-	-		-	-	
Equipment CapEx	1,800,000	1,585,000	(215,000)	-11.9%	1,705,000	120,000	7.6%
Leasehold Improvements	-	-	-		-	-	
Allocation of Fixed Assets							
Inc(Dec) in Fixed Assets (C)	**$ 2,680,543**	**$ 2,952,655**	**$ 272,112**	**10.2%**	**$ 2,884,451**	**$ (68,204)**	**-2.3%**
TOTAL BUDGET (=B + C)	**$ 69,602,175**	**$ 71,321,540**	**$ 1,719,364**	**2.5%**	**$ 73,112,727**	**$ 1,791,188**	**2.5%**
FTEs	**189.88**	**189.88**	**-**		**189.88**	**-**	

Section A — 2015 Business Plan and Budget Program Area and Department Detail

Reliability Standards

Reliability Standards Program (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget - Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	17.98	17.16	(0.82)	17.66	(0.51)
Direct Expenses	$ 3,888,768	$ 3,861,666	$ (27,102)	$ 3,817,110	$ 44,556
Indirect Expenses	4,234,020	4,180,279	(53,741)	4,244,336	(64,056)
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	70,328	58,337	(11,991)	78,490	(20,153)
TOTAL BUDGET	$ 8,193,116	$ 8,100,282	$ (92,835)	$ 8,139,935	$ (39,653)

Background and Scope

The reliability standards program carries out the ERO's statutory responsibility to develop, adopt, obtain approval of, and modify (as and when appropriate) mandatory reliability standards (both continent-wide standards and regional reliability standards) for the reliable planning, operation, and critical infrastructure protection of the North American BES. The major activities undertaken by the Standards department include:

- **Delivering high-quality, continent-wide reliability standards**: NERC standard developers and other standards staff provide project management and leadership to develop solutions necessary to address reliability risks identified through the Reliability Risk Management Process (RRMP). These may include the development of, or modifications to, NERC reliability standards through standard development outreach activities, facilitation of drafting team activities, drafting support, assisting drafting teams in maintaining adherence to the development process as outlined in the *Standard Processes Manual*, and ensuring that the quality of documents produced is appropriate for approval by industry and the Board.
- **Facilitating continent-wide industry engagement**: NERC manages the work of over 200 industry contributors who serve on the Standards Committee, subgroups, and other project teams for the development of NERC reliability standards through the standards development program.
- **Conducting balloting, disseminating information, and supporting regulatory filings**: Through NERC's commenting and ANSI-accredited balloting process, industry consensus is built by engaging thousands of industry volunteers within hundreds of registered entities throughout North America who review, comment on, and approve the standards created by the standard drafting teams. The department also supports the filing of standards with regulatory authorities and provides support with regulatory proceedings.

The reliability standards program provides a mechanism for the eight Regional Entities to process regional standards when unique regional reliability gaps are detected, or incorporate Regional variances into continent-wide standards. The NERC Standards department staff supports regional standards development processes by providing technical advice, final quality review of regional standards, presentation to the Board, and preparation of regional standards materials for submission for standard adoption to the applicable regulatory authorities in the United States and Canada.

Stakeholder Engagement and Cost Effectiveness Project

As part of the standard development process, industry technical experts scope, draft, and review the new or revised NERC reliability standards for approval by the industry ballot body, adoption by the Board, and filing with regulatory authorities in the United States and Canada. Additionally, Federal, State and Provincial regulatory authorities, the NERC Board of Trustees, Regional Entities, and many industry stakeholders have expressed interest in the identification of costs incurred from implementing NERC reliability standards compared to risks they address. The desire is to ensure that these elements are considered during the standards development and revision process. A pilot was conducted in 2016 to develop an approach to determine the level of cost versus the reliability benefit to mitigate an identified risk. Work will continue in 2017 on refining the approach.

Key Efforts Underway

NERC will ensure that the Reliability Standards Development Plan is effectively executed and that reliability standards are focused on and mitigate significant risks to BES reliability. Department resources will be focused on supporting the strategic plan, including but not limited to support of the RRMP and resolving FERC directives. The Standards department will:

1. **Focus on the selection of projects undertaken.** Resources will be expended on issues determined to be a reliability risk through the RRMP (also see Reliability Assessment and System Analysis, and Performance Analysis section for additional detail). The department will apply broader project management skills to implement a variety of solutions to a reliability concern. An effective solution to an identified reliability risk may be a Reliability Standard, or it may be a guideline, information request, training, NERC Alert, technical conference, research, or a combination of these or other tools.
2. **Address FERC directives and respond to FERC orders** through standards development projects, as necessary. Each project will determine whether: (1) the directive will be complied with as issued, (2) there is an equally effective and efficient way to address the concern that fostered the directive, or (3) if there is technical justification (including that the directive has been overcome by events, processes, or advances in technology) that the directive is no longer needed.
3. **Perform Enhanced Periodic Reviews.** In 2016, as the reliability standards reach steady state, industry, NERC, and FERC will determine whether there is a need to make further improvements to the standards through enhanced periodic reviews, that include: (1) a measured review of the content of standards, considering whether the requirements could more effectively mitigate risks to the BPS; (2) whether the standards are results based and drafted with high quality; (3) whether the standards are concise or if the number of requirements could be reduced; and (4) whether compliance expectations are clear.
4. **Facilitate smooth transition to new standards**. This includes working with the Compliance Monitoring and Enforcement, Registration, and Reliability Assessment and System Analysis, and Performance Analysis programs to develop guidelines, webinars, and other activities to support auditor and industry training for the new standards.

The 2017–2019 RSDP will be developed in 2016 in conjunction with the Standards Committee, RISC, and RRMP. It will outline the work plan for the continued evaluation of NERC reliability standards, the Standards department's support of Reliability Risk Management, and resolution of FERC directives. Additionally, associated metrics will be developed and deployed to measure the overall quality of the reliability standard as a basis for measuring needed improvements.

2017 Goals and Deliverables

The transformation of the reliability standards to steady state is nearing completion.[17] Specifically, the majority of FERC directives will be addressed, as well as the remaining recommendations for retiring requirements made by the Paragraph 81 project and the independent experts. The body of standards will be improved while considering quality and content criteria as well as results-based standards principles. The NERC Standards staff will continue to address any new directives issued by FERC as well any reliability risks identified through RRMP or by the RISC for which a Reliability Standard is part of the solution.

Resource Requirements

Personnel

As in prior years, industry engagement is vital to the successful development of standards. The continued transformation of NERC standards to steady state will require additional industry engagement throughout 2016. In 2017, industry subject matter expert engagement requirements will be ongoing as enhanced periodic reviews are performed.

The NERC standards department continues to focus resources on the production of quality standards, rather than solely on the monitoring and execution of the standards process. Workload in the standards area during 2017 is anticipated to remain stable, with no additional personnel resources planned for 2017. The departmental travel expenses are expected to be the same as the 2016 levels, given the anticipated amount of outreach for the number of standards reviews expected to be in process, coupled with cost savings resulting from holding more meetings at NERC's Atlanta and Washington, DC, offices. The FTE reduction set forth in the table at the end of this section is the result of the allocation of standards staff towards more critical activities like cyber security and analytical capabilities

Contractors and Consultants

No contractor and consulting support is budgeted in 2017, which is consistent with the 2016 budget.

[17] As defined in the 2015-2017 RSDP, "steady state" means a stable set of clear, concise, high-quality and technically sound reliability standards that are results based, including retirement of requirements that do little to promote reliability.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
RELIABILITY STANDARDS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 7,869,295	$ 7,869,295	$ (0)	$ 7,835,213	$ (34,082)	$ 7,871,776	$ (36,563)
Penalty Sanctions	218,376	218,376		159,642	(58,734)	162,725	(3,082)
Total NERC Funding	**$ 8,087,671**	**$ 8,087,671**	**$ (0)**	**$ 7,994,855**	**$ (92,816)**	**$ 8,034,500**	**$ (39,645)**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	105,000	105,000	-	105,000	-	105,000	-
Interest	445	5,374	4,929	427	(18)	435	(8)
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 8,193,116**	**$ 8,198,045**	**$ 4,929**	**$ 8,100,282**	**$ (92,834)**	**$ 8,139,935**	**$ (39,653)**
Expenses							
Personnel Expenses							
Salaries	$ 2,260,735	$ 2,349,773	$ 89,039	$ 2,340,405	$ 79,671	$ 2,300,735	39,670
Payroll Taxes	163,064	168,710	5,646	151,658	(11,406)	161,947	(10,289)
Benefits	327,239	289,808	(37,432)	307,085	(20,154)	291,462	15,623
Retirement Costs	250,560	265,961	15,401	259,407	8,847	259,856	(448)
Total Personnel Expenses	**$ 3,001,598**	**$ 3,074,252**	**$ 72,654**	**$ 3,058,556**	**$ 56,958**	**$ 3,014,000**	**44,556**
Meeting Expenses							
Meetings	$ 207,000	$ 207,000	$ -	$ 207,000	$ -	$ 207,000	-
Travel	271,988	230,000	(41,988)	271,988	-	271,988	-
Conference Calls	133,000	100,000	(33,000)	40,565	(92,435)	40,565	-
Total Meeting Expenses	**$ 611,988**	**$ 537,000**	**$ (74,988)**	**$ 519,553**	**$ (92,435)**	**$ 519,553**	**-**
Operating Expenses							
Consultants & Contracts	$ -	$ -	$ -	$ -	$ -	$ -	-
Office Rent	-	-	-	-	-	-	-
Office Costs	64,622	42,784	(21,838)	51,336	(13,286)	51,336	-
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	210,060	231,843	21,783	231,721	21,661	231,721	-
Total Operating Expenses	**$ 275,182**	**$ 275,127**	**$ (55)**	**$ 283,556**	**$ 8,375**	**$ 283,556**	**$ -**
Total Direct Expenses	**$ 3,888,768**	**$ 3,886,379**	**$ (2,389)**	**$ 3,861,666**	**$ (27,102)**	**$ 3,817,110**	**$ 44,556**
Indirect Expenses	**$ 4,234,020**	**$ 4,458,581**	**$ 224,561**	**$ 4,180,279**	**$ (53,741)**	**$ 4,244,336**	**$ (64,056)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 8,122,788**	**$ 8,344,959**	**$ 222,171**	**$ 8,041,945**	**$ (80,843)**	**$ 8,061,445**	**$ (19,500)**
Change in Assets	**$ 70,328**	**$ (146,914)**	**$ (217,242)**	**$ 58,337**	**$ (11,991)**	**$ 78,490**	**(20,153)**
Fixed Assets							
Depreciation	$ (210,060)	$ (231,843)	$ (21,783)	$ (231,721)	$ (21,661)	$ (231,721)	$ -
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	**$ 280,388**	231,639	(48,749)	290,058	9,670	310,211	(20,153)
Inc(Dec) in Fixed Assets (C)	**70,328**	**(204)**	**(70,532)**	**58,337**	**(11,991)**	**78,490**	**(20,153)**
TOTAL BUDGET (=B + C)	**$ 8,193,116**	**$ 8,344,755**	**$ 151,639**	**$ 8,100,282**	**$ (92,834)**	**$ 8,139,935**	**$ (39,653)**
FTEs	**17.98**	**18.27**	**0.29**	**17.16**	**(0.82)**	**17.66**	**-0.51**

Compliance Monitoring and Enforcement and Organization Registration and Certification

The Compliance Monitoring, Enforcement, and Organization Registration and Certification Program Area's purpose is to monitor, enforce, and ensure registered entity compliance with the ERO's mandatory reliability standards. This program area is addressed by three operational groups: Compliance Assurance (addressing compliance monitoring), Reliability Assurance (addressing Assurance, Organization Registration and Certification), and Compliance Enforcement.

Compliance Assurance

Compliance Assurance addresses the Regional Entities' implementation of the compliance monitoring section of the Compliance Monitoring and Enforcement Program (CMEP). The group works in tandem with Compliance Enforcement, Standards, and Reliability Risk Management.

Compliance Assurance

Compliance Assurance (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	19.36	15.51	(3.85)	15.07	0.44
Direct Expenses	$ 4,559,233	$ 3,816,924	$ (742,308)	$ 3,615,394	$ 201,530
Indirect Expenses	4,559,714	3,779,431	(780,283)	3,621,833	157,598
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	301,956	262,244	(39,712)	264,713	(2,469)
TOTAL BUDGET	$ 9,420,903	$ 7,858,599	$ (1,562,304)	$ 7,501,940	$ 356,659

Background and Scope

NERC's Compliance Assurance group works collaboratively with the eight Regional Entities to ensure effective implementation of risk-based compliance monitoring under the CMEP across the entire ERO Enterprise. This program ensures that Regional Entities monitor registered entities for compliance according to their own specific facts and circumstances, including the entity's inherent risks, evaluation of controls in place to mitigate the inherent risks, as well as any aggravating factors. The CMEP provides for Regional Entities to develop customized compliance oversight plans (COPs) for each registered entity that identifies: 1) the standards or requirements to be monitored; 2) the monitoring processes (tools) for use by the Regional Entities, including compliance audits, self-certification, spot checking, investigations, self-reporting, periodic data submittals, and complaints; and 3) the frequency of monitoring. NERC and the Regional Entities ensure that inherent risk assessments (IRAs) for registered entities begin with a consistent framework and that Regional Entities' implementation of the CMEP coalesce around best practices, data management procedures that address data reporting requirements, integrity, retention, security, and confidentiality.

The Compliance Assurance group's responsibilities include but are not limited to the following major activities and functions:

- Oversight of the quality implementation of the risk-based compliance monitoring program;
- Development of the annual Implementation Plan (IP);
- Oversight of the use of necessary compliance-related processes, procedures, IT platforms, tools, and templates;

- Development and delivery of education and training for ERO Enterprise staff;
- Critical Infrastructure Protection (CIP) Version 5 activities related to education programs that support industry compliance and the integration of risk assessment and internal controls;
- CIP-014-1 training and outreach activities related to effective implementation of the Physical Security Reliability Standard;
- Coordination with the NERC Standards department for standard development to assist in the smooth transition for standards from development to enforceability;
- Support for Regional Entity and industry committees, working groups, and task forces, such as the NERC Compliance and Certification Committee; and
- Industry training for every Reliability Standard approved by FERC.

Stakeholder Engagement and Benefit

NERC continues to promote the Regional Entities' development of customized COPs for registered entities. As the risk-based compliance monitoring approach was implemented in 2015 and 2016, Regional Entities worked closely with stakeholders to develop IRAs and appropriately scope compliance monitoring activities. As this process matures in 2017, Regional Entities will continue to develop customized uses of compliance monitoring tools and frequency of monitoring for each registered entity, based on its IRA. Additionally, NERC continues to promote registered entities' development of effective compliance programs and internal controls, which may provide a benefit in the development of their COPs.

Compliance Assurance continues to work closely with the standard development program to provide compliance information, statistics, and perspectives to drafting teams fostering the development of standards that provide an increased reliability benefit and clarify compliance risks. This collaboration with industry and Standards department staff will occur early in the standard development process by providing draft compliance monitoring guidance, including information on how compliance with draft standards will be determined, as well as input to the drafting teams on the auditability and enforceability of the draft standards. This will ensure that ERO Enterprise tools used in the auditing process, such as the reliability standards auditing worksheet (RSAW), do not expand or modify standards requirements.

NERC also continues to provide industry-focused outreach events and webinars on the ERO Enterprise's approaches to risk-based CMEP activities. The ERO Enterprise staff will continue its webinar series providing guidance on standards and requirements associated with the 2017 risk elements identified for consideration for compliance monitoring.

Key Efforts Underway

Regional Entity Oversight for Risk-Based Compliance Monitoring

Consistent with the goals and objectives set forth in the strategic plan, NERC will continue to implement risk-based compliance monitoring and enforcement as part of its stated objectives of ensuring BES reliability, improving the efficiency and effectiveness of NERC and Regional Entity compliance and enforcement operations, focusing on identified risks and reducing unnecessary burdens on registered entities.

CIP Compliance and Transition

NERC and the Regional Entities continue to manage the smooth implementation of compliance activities for Version 5 and subsequent enhancements to the CIP Standards by providing training, webinars, and other forms of outreach. The ERO Enterprise will continue to provide educational programs to support

industry compliance and the integration of risk assessment and internal controls. In addition, NERC and the Regional Entities will continue supporting the successful implementation and monitoring of the physical security reliability standard.

2017 Goals and Deliverables

The Compliance Assurance group has several goals and deliverables that support the 2016-2019 *ERO Enterprise Strategic Plan.* Resources will be focused on building upon the framework and improvements implemented as a result of the risk-based compliance monitoring activities in 2016. Specific 2017 objectives for this group are:

- Continue to mature the risk-based compliance monitoring program, fully developing customized COPs for registered entities.
- Work closely with NERC's Enforcement and IT departments, as well as staff in the Regional Entities, on improvements to the existing compliance, reporting, analysis tracking system (C-RATS), and other compliance tools to support risk-based activities.
- Support the continued successful implementation of the CIP Version 5 reliability standards and subsequent enhancements that become effective in 2017 and beyond.
- Continue to monitor and support effective implementation and monitoring of the Physical Security Reliability Standard.
- Initiate a training program to support implementation of the common audit procedures for each Reliability Standard, integrating principles from the ERO Auditor Capabilities and Competencies Guide.
- Continue to integrate the standards and compliance functions for clear stakeholder implementation. Support this effort through common set of RSAWs, measures, or successors, for all standards. Initiate a compliance phase-in learning periods for new standards.

These 2017 activities are necessary to further implement risk-based compliance monitoring, including the CIP standards, and integrate the standards and compliance functions. A number of activities that support the implementation of the strategic risk-based reforms are intended to reduce regulatory burden by focusing monitoring according to each registered entity's potential impact on the BPS.

Resource Requirements

Personnel

The 2017 FTE reduction set forth in the table at the end of this section reflects the reallocation of 2016 budgeted FTEs to support key initiatives related to successful implementation and oversight of the risk-based CMEP.

Contractors and Consultants

Funds budgeted for outside consultants to assist in successful implementation of risk-based compliance monitoring have been reduced to $50k. While at a significantly reduced level from the 2016 budget, some resources are necessary to support the transformation of NERC's Compliance Monitoring and Enforcement Program to a risk-based design. In addition, the Information Technology budget includes funding for the maintenance of existing software tools supporting compliance assessment, registration, certification, and enforcement activities, as well as the investigation and development of a business case for future tools supporting ERO Enterprise ERO Enterprise compliance assessment, registration, and certification and enforcement activities.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
COMPLIANCE ASSURANCE

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 9,185,250	$ 9,185,250	$ (0)	$ 7,713,879	$ (1,471,371)	$ 7,362,710	$ 351,169
Penalty Sanctions	$ 235,174	$ 235,174		144,334	(90,840)	138,858	5,476
Total NERC Funding	**$ 9,420,424**	**$ 9,420,424**	**$ (0)**	**$ 7,858,213**	**$ (1,562,212)**	**$ 7,501,569**	**$ 356,644**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	-	-	-	-	-	-
Interest	479	4,710	4,231	386	(93)	371	15
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 9,420,903**	**$ 9,425,134**	**$ 4,231**	**$ 7,858,599**	**$ (1,562,305)**	**$ 7,501,940**	**$ 356,659**
Expenses							
Personnel Expenses							
Salaries	$ 3,063,004	$ 2,367,713	$ (695,290)	$ 2,509,618	$ (553,386)	$ 2,342,419	167,199
Payroll Taxes	205,979	159,939	(46,040)	163,335	(42,644)	158,287	5,048
Benefits	351,727	308,546	(43,180)	333,557	(18,170)	315,645	17,912
Retirement Costs	336,902	267,268	(69,634)	276,273	(60,629)	264,902	11,371
Total Personnel Expenses	**$ 3,957,612**	**$ 3,103,467**	**$ (854,145)**	**$ 3,282,783**	**$ (674,828)**	**$ 3,081,253**	**201,530**
Meeting Expenses							
Meetings	$ 60,000	$ 120,000	$ 60,000	$ 60,000	$ -	$ 60,000	-
Travel	276,343	322,000	45,657	276,343	-	276,343	-
Conference Calls	20,000	20,000	-	6,100	(13,900)	6,100	-
Total Meeting Expenses	**$ 356,343**	**$ 462,000**	**$ 105,657**	**$ 342,443**	**$ (13,900)**	**$ 342,443**	**-**
Operating Expenses							
Consultants & Contracts	$ 200,000	$ 115,000	$ (85,000)	$ 50,000	$ (150,000)	$ 50,000	-
Office Rent	-	-	-	-	-	-	-
Office Costs	44,779	38,880	(5,899)	141,198	96,419	141,198	-
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	-	-	-	-	-	-	-
Total Operating Expenses	**$ 245,279**	**$ 154,380**	**$ (90,899)**	**$ 191,698**	**$ (53,581)**	**$ 191,698**	**$ -**
Total Direct Expenses	**$ 4,559,233**	**$ 3,719,847**	**$ (839,386)**	**$ 3,816,924**	**$ (742,309)**	**$ 3,615,394**	**$ 201,530**
Indirect Expenses	**$ 4,559,714**	**$ 3,687,419**	**$ (872,294)**	**$ 3,779,431**	**$ (780,283)**	**$ 3,621,833**	**$ 157,598**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 9,118,947**	**$ 7,407,267**	**$ (1,711,681)**	**$ 7,596,355**	**$ (1,522,592)**	**$ 7,237,227**	**$ 359,128**
Change in Assets	**$ 301,956**	**$ 2,017,868**	**$ 1,715,912**	**$ 262,244**	**$ (39,712)**	**$ 264,713**	**(2,469)**
Fixed Assets							
Depreciation	-	-	-	-	-	-	-
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 301,956	$ 191,574	(110,382)	262,244	(39,712)	$ 264,713	(2,469)
Inc(Dec) in Fixed Assets (C)	**$ 301,956**	**$ 191,574**	**$ (110,382)**	**$ 262,244**	**$ (39,712)**	**$ 264,713**	**$ (2,469)**
TOTAL BUDGET (=B + C)	**$ 9,420,903**	**$ 7,598,841**	**$ (1,822,062)**	**$ 7,858,599**	**$ (1,562,305)**	**$ 7,501,940**	**$ 356,659**
FTEs	**19.36**	**15.11**	**(4.25)**	**15.51**	**(3.85)**	**15.07**	**0.44**

Compliance Analysis, Certification and Registration

Compliance Analysis, Certification and Registration (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	10.14	7.52	(2.62)	9.42	(1.90)
Direct Expenses	$ 2,086,784	$ 1,686,689	$ (400,093)	$ 1,913,981	$ (227,291)
Indirect Expenses	2,387,951	1,832,451	(555,499)	2,263,646	(431,194)
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	158,136	127,149	(30,988)	165,446	(38,297)
TOTAL BUDGET	$ 4,632,871	$ 3,646,289	$ (986,581)	$ 4,343,072	$ (696,783)

Background and Scope

The Reliability Assurance (Assurance, Certification and Registration) group is responsible for a range of requirements and activities embodied in Section 500 (Organization Registration and Certification) and Appendices 5A and 5B of the NERC Rules of Procedure. The group provides technical resource support to standards development, compliance monitoring, and enforcement and ensures that (1) all entities impacting the BES are registered commensurate with risk; (2) all RCs, TOPs, and BAs are certified; (3) conducts industry reliability assurance activities; and (4) compliance gaps identified in reportable events are assessed and addressed if appropriate. Specific activities of the group include:

- **Registration** – Identifies and registers BES users, owners, and operators who are responsible for compliance with reliability standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and complying with all applicable reliability standards. Maintains the current registration for the entire ERO for entities as they take on and drop functional responsibilities.
- **Certification** – Evaluates and certifies the competency of reliability entities; i.e., those that perform certain key reliability functions, specifically the RC, BA, and TOP functions. Entities performing these three functions must be evaluated for having the necessary personnel, knowledge, facilities, programs, and other qualifications to carry out these important responsibilities, including demonstrating the ability to meet the requirements and sub-requirements of all of the reliability standards applicable to the reliability function(s). This also includes confirming through the certification review process that a reliability entity continues to have the qualifications mentioned above following planned material changes to that entity's operation.
- **Reliability Assurance** – Conducts reliability assurance activities, including:
    - **Reliability Assurance** – Conduct activities to reasonably assure the ERO that certain actions have been taken as reported in response to NERC Alerts or guidance to industry. An example of this is the Right-of-Way Clearances, which is one of the 2015 ERO Enterprise high-priority risk projects.
    - **Oversight** – NERC provides oversight of Regional Entity implementation of regional registration, compliance, certification, investigation, complaint programs, and processes.
    - **Investigations** – Staff conducts non-public, confidential investigations to identify Possible Violations of NERC reliability standards in response to complaints, BES disturbances, or other similar triggers. Staff participates on all Regional Entity-led investigations and observe as requested on FERC-led reliability investigations and inquiries.

- **Compliance evaluations** – Staff works closely with regional staff to confirm that qualified events and disturbances are evaluated against the relevant approved reliability standards and ensure formal compliance monitoring occurs if indicated. These analyses are also shared with FERC staff.
- **Complaints** – NERC addresses formal complaints that allege the violation of reliability standards through a confidential process.

Key Efforts Underway

In 2014 and 2015, the Reliability Assurance, Certification and Registration group developed the risk-based Registration (RBR) design and registration criteria. FERC approved the design in 2015 in two orders, March 15 and October 15, which included the deactivation of Interchange Authorities (IAs), Load Serving Entities (LSEs) and Distribution Providers below 75 MW (DPs), as well as the creation of a NERC-led panel (Panel). In 2016, the ERO Enterprise implemented the Panel to review entities for deregistration or applicability to a reduced number of standards. The Panel will continue to review registration for individual entities and evaluate trends to determine emerging classes of similarly situated entities in 2017. In 2016, a review and identification of potential improvements in both the Registration and Certification programs is being undertaken. Improvements identified, will be considered for implementation in 2017.

2017 Goals and Deliverables

The Reliability Assurance group has several goals and deliverables that support the 2016-2019 *ERO Enterprise Strategic Plan.* Resources will be focused on building upon the improvements identified in 2016. Specific 2017 objectives for this group are:

- Continue to mature the NERC-led panel.
- Implement registration program improvements identified in the 2016 project, and conduct any additional actions identified by the project. Conduct training as necessary.
- Implement certification program improvements identified in the 2016 project and conduct training as necessary.

Resource Requirements

Personnel

No additional personnel are budgeted for 2017. The FTE count in the table at the end of this section reflects the 2016 merger of the registration and reliability assurance groups.

Contractor Expenses

No contractor expenses are budgeted in 2017.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
COMPLIANCE ANALYSIS, CERTIFICATION and REGISTRATION

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)
Funding					
ERO Funding					
NERC Assessments	$ 4,509,458	$ 4,509,458	$ 0	$ 4,256,053	$ (253,404)
Penalty Sanctions	$ 123,162	$ 123,162		86,786	(36,376)
Total NERC Funding	**$ 4,632,620**	**$ 4,632,620**	**$ 0**	**$ 4,342,840**	**$ (289,780)**
Third-Party Funding	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	251	251	0	232	(19)
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 4,632,871**	**$ 4,632,871**	**$ 0**	**$ 4,343,072**	**$ (289,799)**
Expenses					
Personnel Expenses					
Salaries	$ 1,410,333	$ 1,276,351	$ (133,982)	$ 1,284,717	$ (125,615)
Payroll Taxes	97,779	89,383	(8,396)	89,953	(7,826)
Benefits	184,238	200,291	16,053	208,842	24,604
Retirement Costs	157,451	144,473	(12,977)	145,981	(11,470)
Total Personnel Expenses	**$ 1,849,801**	**$ 1,710,498**	**$ (139,302)**	**$ 1,729,494**	**$ (120,307)**
Meeting Expenses					
Meetings	$ 4,000	$ 3,000	$ (1,000)	$ 4,000	$ -
Travel	155,146	134,000	(21,146)	155,146	-
Conference Calls	2,000	2,000	-	610	(1,390)
Total Meeting Expenses	**$ 161,146**	**$ 139,000**	**$ (22,146)**	**$ 159,756**	**$ (1,390)**
Operating Expenses					
Consultants & Contracts	$ 50,000	$ 50,000	$ -	$ -	$ (50,000)
Office Rent	-	-	-	-	-
Office Costs	25,338	17,365	(7,972)	24,231	(1,106)
Professional Services	-	-	-	-	-
Miscellaneous	500	500	-	500	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 75,838**	**$ 67,865**	**$ (7,972)**	**$ 24,731**	**$ (51,106)**
Total Direct Expenses	**$ 2,086,784**	**$ 1,917,364**	**$ (169,420)**	**$ 1,913,981**	**$ (172,803)**
Indirect Expenses	**$ 2,387,951**	**$ 2,274,301**	**$ (113,650)**	**$ 2,263,646**	**$ (124,305)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 4,474,734**	**$ 4,191,664**	**$ (283,070)**	**$ 4,177,626**	**$ (297,108)**
Change in Assets	**$ 158,136**	**$ 441,207**	**$ 283,070**	**$ 165,446**	**$ 7,309**
Fixed Assets					
Depreciation	-	-	-	-	-
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	$ 158,136	$ 118,030	(40,107)	165,446	7,309
Inc(Dec) in Fixed Assets (C)	**$ 158,136**	**$ 118,030**	**$ (40,107)**	**$ 165,446**	**$ 7,309**
TOTAL BUDGET (=B + C)	**$ 4,632,871**	**$ 4,309,694**	**$ (323,177)**	**$ 4,343,072**	**$ (289,799)**
FTEs	**10.14**	**9.55**	**(0.59)**	**9.42**	**(0.72)**

Compliance Enforcement

Compliance Enforcement (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	12.22	13.16	0.94	12.25	0.91
Direct Expenses	$ 2,225,938	$ 2,371,347	$ 145,410	$ 2,376,067	$ (4,720)
Indirect Expenses	2,876,962	3,206,790	329,827	2,942,739	264,050
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	190,398	222,510	32,112	215,079	7,431
TOTAL BUDGET	$ 5,293,298	$ 5,800,647	$ 507,350	$ 5,533,886	$ 266,761

Background and Scope

The Compliance Enforcement department is responsible for overseeing enforcement processes, the application of penalties or sanctions, and activities to mitigate and prevent recurrence of noncompliance with reliability standards. The Compliance Enforcement department works collaboratively with the eight Regional Entities to ensure consistent and effective implementation of the risk-based Compliance Monitoring and Enforcement Program. Importantly, the department also focuses on ensuring that the ERO Enterprise dedicates resources to the matters that pose the greatest risk to reliability.

The NERC Compliance Enforcement department performs its responsibilities by:

- Monitoring Regional Entities' enforcement processes and providing oversight over their outcomes to ensure due process, to identify best practices and process efficiency opportunities, and to promote consistency among Regional Entities' business practices;
- Collecting and analyzing compliance enforcement data and trends to assist with the identification of emerging risks and to help inform the development of enforcement policies and processes;
- Filing notices of penalty and other submittals associated with noncompliance discovered through Regional Entity compliance monitoring and enforcement activities;
- Processing and filing notices of penalty and other submittals associated with violations discovered through NERC-led investigations and audits;
- Collaborating with other NERC departments, including Compliance Assurance, Standards, Event Analysis, and Regional Entity Coordination; and
- Delivering training of the ERO Enterprise staff and registered entities, as well as supporting other outreach efforts.

The ERO Enterprise's enforcement jurisdiction is drawn from the Energy Policy Act of 2005 (the Act), which added section 215 to the Federal Power Act (FPA). Section 215 made compliance with electric reliability standards mandatory and authorized the creation of an ERO and Regional Entities to establish and enforce reliability standards. Under section 215(e)(1) of the FPA, NERC or a Regional Entity may impose a penalty on a user, owner, or operator of the BPS for a violation of a Reliability Standard approved by FERC. As the ERO, NERC has set forth Sanction Guidelines outlined in its Rules of Procedure that govern the ERO Enterprise's penalties and non-monetary sanctions for Reliability Standard violations. This document provides information on the ERO Enterprise's enforcement philosophy, i.e., the ERO Enterprise's approach for assessing and resolving noncompliance while continuing to work to bring entities into compliance with applicable reliability standards.

ERO Enterprise Core Values and Guiding Principles

The ERO Enterprise's 2016-2019 Strategic Plan[18] promotes the ERO Enterprise's core values and guiding principles, which are based on accountability and independence, responsiveness, fairness and inclusiveness, adaption and innovation, excellence, efficiency, and integrity. These core values and guiding principles support the four pillars of the ERO Enterprise's efforts, namely, reliability, assurance, learning, and a risk-based approach.

Strategic Goals Related to Enforcement

Strategic goal 2 provides that the ERO Enterprise shall:

> [b]e a strong enforcement authority that is independent, without conflict of interest, objective and fair, and promote a culture of reliability excellence through risk-informed compliance monitoring and enforcement. The ERO Enterprise retains and refines its ability to use standards enforcement when warranted and imposes penalties and sanctions commensurate with risk. The ERO Enterprise retains and refines its ability to use reliability standards enforcement when warranted and imposes penalties and sanctions commensurate with risk.

The risk-based enforcement approach allows for the appropriate allocation of resources to the issues that pose a higher level of risk to the reliability of the BPS.

Guiding Enforcement Principles

The following principles serve as guidelines for the conduct and behavior of all involved in the ERO Enterprise enforcement program to ensure alignment with strategic goal 2 and the ERO Enterprise's core values.

Compliance Enforcement Authorities are independent, without conflict of interest, objective, and fair.

The ERO Enterprise strives to be a strong enforcement authority that is independent, without conflict of interest, objective, and fair. NERC and each of the Regional Entities has a code of conduct addressing the professional and ethical standards applicable to its personnel. Foremost among these standards is the requirement that no person work on a matter where that work may affect the person's financial interest. The ERO Enterprise also expects its personnel to conduct themselves professionally and respectfully when engaging with registered entities or other stakeholders. Personnel who do not meet these standards are subject to discipline, up to and including termination.

Enforcement program promotes culture of reliability excellence through a risk-based approach.

The ERO Enterprise's risk-based enforcement philosophy generally advocates reserving enforcement actions under section 5.0 of the Compliance Monitoring and Enforcement Program for those issues that pose a higher risk to the reliability of the BPS. The risk of a noncompliance is determined based on specific facts and circumstances, including any controls in place at the time of the noncompliance. The ERO Enterprise works with registered entities to ensure timely remediation of potential risks to the reliability of the BPS and prevent recurrence of noncompliance. The enforcement process allows parties to address risks collaboratively and promote increased compliance and reliability through improvement of programs and controls at the registered entities.

The ERO Enterprise applies a presumption of non-enforcement treatment of minimal risk noncompliance to entities with demonstrated internal controls who are permitted to self-log such minimal risk issues. Regarding other issues posing a minimal risk, NERC and the Regional Entities may exercise appropriate

[18] The ERO Enterprise's 2016-2019 Strategic Plan

judgment whether to initiate a formal enforcement action or resolve the issue outside of the formal enforcement processes. The availability of streamlined treatment of minimal risk noncompliance outside of the formal enforcement process encourages self-inspection by registered entities. When self-identified minimal risk noncompliance is more than likely not going to be subject to a financial penalty, registered entities are encouraged to establish more robust internal controls for the detection and correction of noncompliance. This approach allows the ERO Enterprise to oversee the activities of registered entities in a more efficient manner and to focus resources where they result in the greatest benefit to reliability. In this context, efficiency does not necessarily mean less time or effort. Rather, it is using the requisite time, knowledge, and skills required for each circumstance. In addition, this approach allows the ERO Enterprise to continue to provide clear signals to registered entities about identified areas of concern and risk prioritization, while maintaining existing visibility into potential noncompliance and emerging areas of risk. Outcomes for noncompliance are based on the risk of a specific noncompliance and may range from streamlined, non-enforcement processes, to significant monetary penalties.

Enforcement actions are used and penalties are imposed when warranted, commensurate with risk.
An element of a risk-based approach to enforcement is accountability of registered entities for their noncompliance. No matter the risk of the noncompliance, the registered entity still bears the responsibility of mitigating that noncompliance. Based on the risk, facts, and circumstances associated with that noncompliance, the Regional Entity decides on an appropriate disposition track, inside or outside of an enforcement action, as described above, and whether a penalty is appropriate for the noncompliance.

Penalties are generally warranted for serious risk violations (e.g., uncontrolled loss of load, CIP program failures) and for when repeated noncompliance constitutes an aggravating factor. In addition to the use of significant penalties to deter undesired behavior, the ERO Enterprise also incents desired behaviors.[19] Specifically, Regional Entities may offset penalties to encourage valued behavior. Factors that may mitigate penalty amounts include registered entity cooperation, accountability (including admission of violations), culture of compliance, and self-identification of noncompliance.

Regional Entities may also grant credit in enforcement determinations for certain actions undertaken by registered entities for improvements in addition to mitigating factors. For example, Regional Entities may consider significant investments in reliability made by registered entities, beyond those otherwise planned and required, as an offset for proposed penalties in enforcement determinations. Regional Entities do not award credits or offsets for actions or investments undertaken by a registered entity that are required to mitigate noncompliance.

NERC engages in regular oversight of Regional Entity enforcement activities to confirm that the Regional Entities have followed the CMEP. This oversight evaluates the consistency of disposition methods, including assessment of a penalty or sanction, with previous resolutions of similar noncompliance involving similar circumstances. The NERC Board of Trustees Compliance Committee (the Compliance Committee) considers the recommendations of NERC staff regarding approval of Full Notices of Penalty and monitors the handling of noncompliance through the streamlined disposition methods of Spreadsheet NOPs, FFTs, and Compliance Exceptions.

[19] The Sanction Guidelines, Appendix 4B to the NERC Rules of Procedure, in alignment with Section 215, establish a general rule that penalties and sanctions imposed for the violation of a Reliability Standard shall bear a reasonable relation to the seriousness of the violation while also reflecting consideration of the other factors specified in the Sanction Guidelines. The Sanction Guidelines are available on NERC's website.

Actions are timely and transparent.
The ERO Enterprise maintains an elevated level of transparency regarding enforcement matters. NERC's Rules of Procedure (including the CMEP and Sanction Guidelines) and program documents are available to the public.[20] NERC also posts information on enforcement actions on a monthly basis.[21] Moreover, information on the efficiency of the enforcement program is available to the public on a quarterly basis.[22]

Noncompliance information is used as an input to other processes.
When developing risk elements, NERC annually identifies and prioritizes risks to the reliability of the BPS, taking into account factors such as compliance findings, event analysis experiences, and data analysis. In addition, Regional Entities consider factors such as noncompliance information when conducting an IRA of a registered entity. The ERO Enterprise also uses noncompliance information as part of a feedback loop to the standards development process. This allows enhanced reliability standards through appropriate information flows from compliance monitoring and enforcement to the standards drafting process and other NERC programs. NERC regularly provides analysis and lessons learned from noncompliance information to the public.[23]

Stakeholder Engagement and Benefit

Over the past few years, NERC and the Regional Entities have made substantial progress in reducing the number of instances of noncompliance remaining to be evaluated and processed. The ERO Enterprise has held registered entities accountable for instances of noncompliance that posed a risk to the reliability of the BPS while ensuring that enforcement actions are timely and transparent. NERC promotes a culture of reliability excellence by examining registered entities' internal compliance programs and considering them as mitigating factors in penalty determinations.

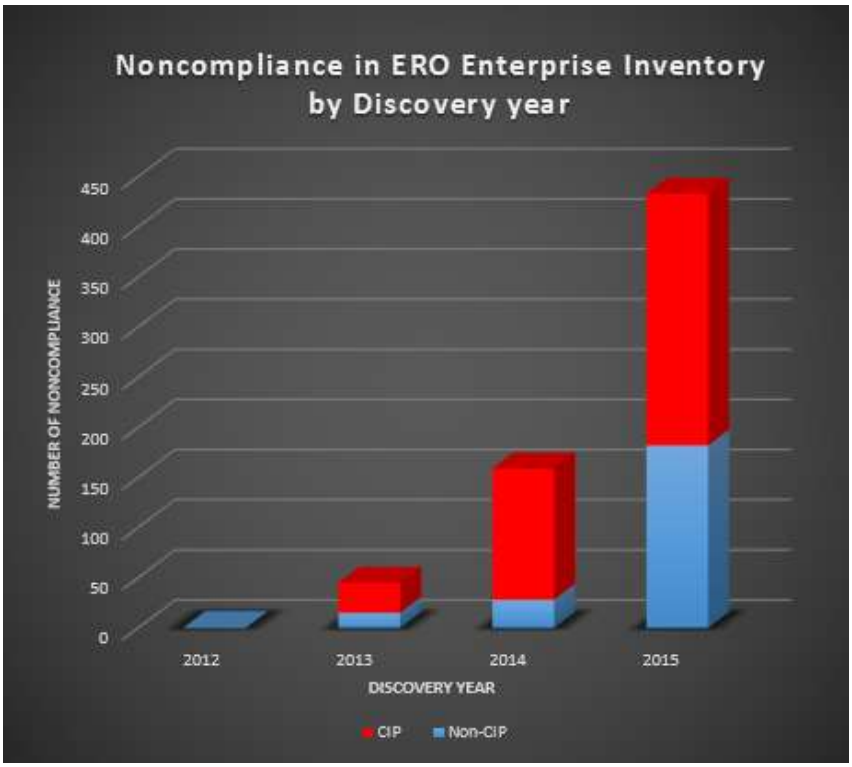
Processing Efficiencies

In an effort to improve the efficiency of enforcement processing throughout the ERO Enterprise, NERC developed a series of key enforcement processing metrics, which are tracked and analyzed throughout the year. In addition, since 2012, NERC has established goals to reduce the number of older violations remaining to be processed. Working with NERC, the Regional Entities invested significant time and resources in processing the older violations. As a result, the ERO Enterprise as a whole reduced the number of older violations substantially.

As of the end of 2015, there were three hundred twenty (320) violations older than 24 months. Sixty-four (64) of these violations stemmed from 9 non-federal registered entities and two hundred fifty-six (256) violations derived from 13 federal registered entities. The vast majority of the violations have either been fully mitigated or have mitigation plans in progress.

The targets and thresholds for processing efficiency-related metrics remain the same in 2016. This is because the ERO Enterprise is stable with regard to enforcement processing. This has only been possible due to the hard work of the Regional Entities and NERC Enforcement in eliminating backlog and incorporating new enforcement processes and procedures into practice.

[20] The NERC Rules of Procedure
[21] Posted compliance exceptions, Spreadsheet Notices of Penalty, and Full Notices of Penalty
[22] Quarterly enforcement program
[23] Quarterly compliance reports



Continued Outreach Efforts in 2016 and Beyond

In 2016, NERC and the Regional Entities will continue to conduct outreach activities that focus on self-logging, compliance exceptions, risk elements, CIP Version 5, Inherent Risk Assessments, and internal controls. NERC plans to use existing industry events, such as the Standards and Compliance workshops and industry webinars, to provide information on compliance monitoring and enforcement activities.

In addition, NERC and the Regional Entities will conduct industry outreach on reliability standards approved by FERC in 2016. These events will focus on the approved new standards or modifications to existing standards along with implementation timelines. Although most events will take place via webinar, some events will be delivered as workshops.

Risk-Based CMEP Implementation

On February 19, 2015, FERC approved the implementation of the risk-based CMEP. The goal of the risk-based CMEP is to shift the compliance and enforcement approach from one in which all instances of noncompliance are evaluated as Possible Violations to an approach that strengthens management practices and reserves the enforcement process for instances of noncompliance that have been found to pose a greater risk to reliability. The programs discussed below, in conjunction with compliance outreach encouraging the development of strong management practices, will advance NERC's progress toward this goal.

Compliance Exceptions

A compliance exception is an alternative disposition method and is not a dismissal, Find, Fix, Track (FFT), or Notice of Penalty. It is essentially the exercise of enforcement judgment with respect to a noncompliance regardless of its method of discovery (self-report, self-certification, compliance audit finding, etc.). The process of identifying and recording a compliance exception builds on the FFT program. The ERO Enterprise uses judgment in the process by taking into account the facts and circumstances of the noncompliance, the risk posed by the noncompliance to the reliability of the BPS, and the deterrent

effect of an enforcement action or penalty, among other things. Compliance exception treatment is available for issues that pose a minimal risk to the BPS that would be mitigated within 12 months of the date the compliance exception is posted.

In 2013 and 2014, the use of compliance exceptions (as the alternative disposition for noncompliance posing a minimal risk to the reliability of the BPS) was limited to allow the testing of the new process. In 2015, this disposition track became available throughout the ERO Enterprise. Use of compliance exceptions as a disposition track has increased steadily. Minimal risk issues continue to be the majority of the caseload. Regional Entities have continued to use the compliance exception disposition method and increasingly relied upon it for minimal-risk issues. The increase in compliance exception use has corresponded with a decline in the use of the FFT disposition track.



Self-Logging

NERC and Regional Entity enforcement staff also have worked closely with stakeholders to identify potential improvements to self-reporting and other enforcement processes. A number of improvements were designed and implemented in 2013 and 2014. The self-logging program allows registered entities that have demonstrated effective management practices to keep track of minimal-risk noncompliance (and related mitigation) on a log that is periodically reviewed by the Regional Entity.

In November 2015, FERC approved the ERO Enterprise Self-Logging Program document, which includes the method to evaluate eligibility.[24] The program is available to any registered entity that would like to be evaluated by its Regional Entity in accordance with the program requirements. Self-logging became available to all registered entities that met the program qualifications at the start of 2015, and 42 registered entities have been approved by Regional Entities to self-log as of December 31, 2015. NERC is conducting a review of the self-logging program, in coordination with FERC staff, during 2016.

NERC Oversight of Risk-Based CMEP Implementation

For 2016, ensuring the successful implementation of NERC's risk-based CMEP remains the priority of Compliance Enforcement's oversight plan. As part of that oversight and in addition to offering regular feedback to the Regional Entities, NERC will continue to identify areas for improvement or promoting

[24] *North American Electric Reliability Corporation*, 153 FERC ¶ 61,130 (2015). The self-logging program document is available on NERC's website.

consistency through training, guidance, or adjustment the following year. NERC also produces an ERO Enterprise CMEP annual report, which includes an assessment of the risk-based CMEP implementation. NERC expects to publish that report during Q1 2017.

NERC performs oversight of the Regional Entities' enforcement programs primarily through the review of the processes, supporting evidence, and other information provided by the Regional Entities over the course of focused engagements of program areas that are scheduled throughout the year. NERC communicates the recommendations and findings to the Regional Entities to help the ERO Enterprise develop responsive strategies and solutions to potential issues and ensure uniform and consistent implementation of the CMEP. Such recommendations and findings also help identify priority areas for training of ERO Enterprise staff during the year.

Other Key Enforcement Efforts Underway

Regional Entity Training

NERC Enforcement will provide training to Regional Entity staff on the most important elements of risk-based enforcement, including risk assessment of noncompliance and the determination of appropriate penalties and sanctions for noncompliance. NERC is developing this training based on observations from its oversight activities of Regional Entity settlement agreements, as well as the process reviews described above.

2017 Goals and Deliverables

Specific 2017 objectives for the Compliance Enforcement department include:

- Refining and improving the risk-based CMEP processes;
- Implementing in a transparent manner an ERO Enterprise enforcement philosophy that is risk focused and drives desired behaviors by registered entities;
- Expanding the feedback loop of information from Enforcement to Standards and other program areas; and
- Working closely with NERC's Compliance Assurance and Information Technology departments, as well as staff in the Regional Entities, regarding the evaluation of improvements in the existing compliance, reporting, analysis tracking system, and other compliance tools to support risk-based activities.

Resource Requirements

Personnel

No changes to current Enforcement staffing levels are proposed in 2017.

Contractor Expenses

The Information Technology budget includes funding for the maintenance, evaluation, and development of enterprise tools supporting technical feasibility exceptions, registration, and enforcement activities.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
COMPLIANCE ENFORCEMENT

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 5,144,612	$ 5,144,612	$ 0	$ 5,677,854	$ 533,242	$ 5,420,762	$ 257,092
Penalty Sanctions	148,384	$ 148,384		122,465	(25,919)	112,822	9,643
Total NERC Funding	**$ 5,292,996**	**$ 5,292,996**	**$ 0**	**$ 5,800,319**	**$ 507,323**	**$ 5,533,584**	**$ 266,735**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	-	-	-	-	-	-
Interest	302	3,682	3,380	327	25	302	26
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 5,293,298**	**$ 5,296,678**	**$ 3,380**	**$ 5,800,647**	**$ 507,349**	**$ 5,533,886**	**$ 266,761**
Expenses							
Personnel Expenses							
Salaries	$ 1,629,233	$ 1,755,799	$ 126,566	$ 1,790,859	$ 161,627	$ 1,791,830	(971)
Payroll Taxes	109,485	113,380	3,895	117,205	7,720	117,447	(241)
Benefits	222,877	176,404	(46,473)	184,106	(38,771)	185,432	(1,326)
Retirement Costs	181,419	196,458	15,039	198,694	17,275	200,877	(2,182)
Total Personnel Expenses	**$ 2,143,014**	**$ 2,242,042**	**$ 99,028**	**$ 2,290,865**	**$ 147,851**	**$ 2,295,585**	**(4,720)**
Meeting Expenses							
Meetings	$ 2,500	$ 2,500	$ -	$ 2,500	$ -	$ 2,500	-
Travel	56,736	55,000	(1,736)	56,736	-	56,736	-
Conference Calls	1,200	2,000	800	366	(834)	366	-
Total Meeting Expenses	**$ 60,436**	**$ 59,500**	**$ (936)**	**$ 59,602**	**$ (834)**	**$ 59,602**	**$ -**
Operating Expenses							
Consultants & Contracts	$ -	$ -	$ -	$ -	$ -	$ -	-
Office Rent	-	-	-	-	-	-	-
Office Costs	21,866	14,983	(6,883)	20,379	(1,486)	20,379	-
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	1,000	500	500	-	500	-
Depreciation	122	122	-	-	(122)	-	-
Total Operating Expenses	**$ 22,488**	**$ 16,105**	**$ (6,383)**	**$ 20,879**	**$ (1,608)**	**$ 20,879**	**$ -**
Total Direct Expenses	**$ 2,225,938**	**$ 2,317,647**	**$ 91,708**	**$ 2,371,347**	**$ 145,409**	**$ 2,376,067**	**$ (4,720)**
Indirect Expenses	**$ 2,876,962**	**$ 2,989,470**	**$ 112,507**	**$ 3,206,790**	**$ 329,827**	**$ 2,942,739**	**$ 264,050**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 5,102,901**	**$ 5,307,116**	**$ 204,216**	**$ 5,578,137**	**$ 475,236**	**$ 5,318,807**	**$ 259,330**
Change in Assets	**$ 190,398**	**$ (10,438)**	**$ (200,836)**	**$ 222,510**	**$ 32,112**	**$ 215,079**	**7,431**
Fixed Assets							
Depreciation	(122)	(122)	-	-	122	-	-
Computer & Software CapEx	-	107,000	107,000	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 190,520	$ 155,313	(35,207)	222,510	31,990	$ 215,079	7,431
Inc(Dec) in Fixed Assets (C)	**$ 190,398**	**$ 262,191**	**$ 71,793**	**$ 222,510**	**$ 32,112**	**$ 215,079**	**$ 7,431**
TOTAL BUDGET (=B + C)	**$ 5,293,298**	**$ 5,569,308**	**$ 276,009**	**$ 5,800,647**	**$ 507,349**	**$ 5,533,886**	**$ 266,761**
FTEs	**12.22**	**12.25**	**0.03**	**13.16**	**0.94**	**12.25**	**0.91**

Reliability Assessment and System Analysis

Reliability Assessments and System Analysis (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	11.75	14.10	2.35	14.13	(0.03)
Direct Expenses	$ 3,778,595	$ 3,986,965	$ 208,370	$ 4,031,697	$ (44,731)
Indirect Expenses	2,768,236	3,435,846	667,610	3,395,468	40,378
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	(202,709)	112,782	315,491	122,547	(9,765)
TOTAL BUDGET	$ 6,344,123	$ 7,535,594	$ 1,191,470	$ 7,549,713	$ (14,119)

Background and Scope

The Reliability Assessment and System Analysis (RASA) department carries out the ERO's statutory responsibility to conduct assessments of the reliability and adequacy of the BES. These assessments are used to provide insight and guidance about reliability risks. These insights provide a foundation for the development of new reliability standards or modifications to mandatory reliability standards, or other initiatives, such as guidelines, alert(s), webinars, etc., all focused on enhancing overall reliability. The majority of the activities in the RASA department directly address the risk priorities established by the Reliability Issues Steering Committee. In particular, the risks pertaining to changing resources and planning noted in the 2015 RISC report are of particular importance to the assessment and analysis work being performed in RASA.

NERC staff works closely with stakeholders on creating assessment development schedules, including schedules with adequate stakeholder review at every level. All NERC reliability assessments have a sponsoring technical committee, subcommittee, or other subgroup. The Long-Term and Seasonal assessments are conducted by the Reliability Assessment Subcommittee, and ultimately endorsed by the Planning Committee. Special Assessments often require a separate and specialized task force or advisory group to help construct, conduct, and produce special topic assessments such as the CPP assessments, Natural Gas interdependency assessment, and distributed energy report.

The department focuses on developing a technical framework and understanding the emerging reliability risks facing the industry. It also provides guidance and insights to stakeholders across North America. The department relies on its own engineering and analysis expertise, as well as Regional Entity and stakeholder resources. RASA is responsible for:

- Independent reliability assessments on the overall reliability and adequacy of the BES and associated emerging reliability risks that could impact the short-, mid- and the long-term (e.g., 10-year) planning horizons, and other reliability issues requiring an in-depth analysis.
- Support for the development and improvement of long-term sustainable interconnection-based power flow, dynamic, and load models that exhibit the accuracy and fidelity reflecting actual BES reliability performance and dynamic conditions.
- Interconnection-wide analysis of steady-state and dynamic conditions, including frequency, Essential Reliability Services, stability, and oscillatory behavior aspects.

- Advancement of industry and the ERO's understanding of power system characteristics and behaviors by gathering larger PMU datasets of data for advanced data analytics and modeling improvements.

- Assurance oversight that the BES electrical elements necessary for its reliable operation are identified, requiring the elements to follow the appropriate NERC Reliability Standards.

- Establishment of reliability leadership and consistent, technically sound guidance and recommendations that position industry and policy makers to enhance reliability through effective outreach and communications.

Stakeholder Engagement and Benefit

RASA works with industry leaders to create a reliability strategy that is relevant, timely, and effective to address the most important reliability risks. This effort includes reviewing and addressing key priority risks identified by NERC's Reliability Issues Steering Committee's (RISC); synthesizing key information identified through analysis and assessment efforts; extracting and prioritizing the associated reliability risks; sharing and integrating risk analysis insights across the ERO Enterprise; and translating that knowledge into actionable guidance and recommendations for NERC management, the Board, and entities, along with state, federal, and provincial policy makers.

In addition, the ERO monitors the ongoing and historic reliability performance of the BES through data gathered to analyze historic trends. The ERO provides reports and recommendations regarding the anticipated conditions that could impact the reliability, security, and stability of the BPS to the industry, Regional Entities, regulatory entities, and other designated entities.

2017 Enhancements

Enhancements in the 2017 BP&B are a reflection of the strategic goals and objectives identified in the Electric Reliability Organization Enterprise Strategic Plan 2016–2019.[25] The following enhancements are attributable to strategic goal #4[26] and the objectives and valued outcomes noted within the goal #4a:

- Improve resource adequacy assessments with increased probabilistic and risk analysis
- Conduct interconnection-wide analysis to support NERC's reliability assessments and improve industry planning
- Increase technical analysis and assessment focus on natural gas, wind, and solar resource and fuel availability
- Develop technical references and guidelines that advance and improve reliability using new technologies
- Develop quality/fidelity assessments of interconnection models

Key RASA Efforts Underway

RASA focuses its efforts in the following key areas:

Reliability Assessment

Reliability assessments serve to evaluate the expected reliability of the BES through extensive deterministic and probabilistic analyses to identify potential reliability risks and potential mitigation approaches. These reviews include both evaluations at the edge of the planning horizon, as well as

[25] http://www.nerc.com/AboutNERC/Documents/ERO%20Enterprise%20Strategic%20Plan%202016%E2%80%932019.pdf

[26] ERO Enterprise identifies, evaluates, studies, and independently assesses emerging risks to reliability.

assessments of the anticipated performance during the short-term (12- to 18-month outlook). These analyses involved planned and anticipated changes to generation resources, transmission infrastructure, and load behavior compared to base-line needs of the system to remain reliable and formulate recommendations and related guidance. This assessment is often by completed by examining special scenarios and unique situations within the BES. These analyses provide a technical platform for important policy discussions on challenges facing the interconnected BES, as well as focused recommendations on mitigation to improve overall reliability or lessen reliability risks.

By identifying and quantifying emerging reliability issues, NERC is able to provide risk-informed recommendations and support a learning environment for industry to address emerging risks and pursue improved reliability performance. These efforts are expected to expand to assess the impacts on reliability from the changing resource mix, reliability behavior of resources, distributed energy resources, and loads. Many resource additions are asynchronous and energy-limited, requiring assessment of a substantial number of scenarios rather than just seasonal peak conditions. Reliability assessments must therefore include a greater focus on probabilistic approaches, assessing the sufficiency of essential reliability services as well as focusing seasonal assessments on short-term horizons to encompass more than peak condition reserve margin analyses.

Key assessments include:

- Long-Term Reliability Assessment (supplemented by the Probabilistic Assessment)
- Summer and Winter Reliability Assessments (condensed report)
- Short-Term and Special Reliability Assessments
    a. Between one and four short-term reliability assessments are expected, driven by the need to assess emerging short-term risks to reliability
    b. Special Assessments are selected based on high-priority/high-risk issues that require an independent assessment from the ERO.

A significant ongoing effort anticipated to involve RASA, Regional Entity staff, and stakeholders focuses on the continued development of effective Essential Reliability Services. These efforts are expected to lead to a broad set of recommendations that will culminate with defined elements, an evaluation of initial metrics and data compilation of actual performance, and refinement about the ongoing assessment of Essential Reliability Services measures.

System Analysis

Understanding the technical behavior of the North American grid is the foundation for identifying crucial aspects of performance that are important for sustaining overall reliability. NERC's understanding of grid behavior is achieved through a comprehensive evaluation of system behavior through constant observation and study, analytic simulations, and forensic analysis of system disturbances. Methodically comparing the simulation results of powerflow and system dynamic performance to actual system behavior improves models critical for industry use to simulate system conditions as well as enables RASA to gain insights to enhance predictive system analysis.

The ERO Enterprise RAPA team also supports the following objectives:

- Continue leading and improving NERC's analytical capabilities to address a broad range of engineering topics,
- Support NERC Reliability Standards development with subject matter expertise,
- Support and lead technical analysis of emerging risks requiring advanced analytics and interconnection-wide assessment,

- Detailed forensic analysis of significant system disturbances

Key focus areas:

- PMU Measurement, use, and analysis improvements
  - Synchrophasor technology
  - Power plant model verification
  - Oscillation analysis
- Frequency Response Analysis, Interconnection Frequency Response Obligation Analysis, and forward-looking reliability assessment
- Interconnection-Wide Model Building Designation and Criteria administration
- Analysis of TPL Footnote 12
- Load and distributed energy resource modeling
- Event analysis – simulation and forensic analysis of major events
- Reliability Standards support
- BES Exception and Self-Determined Notification Processing

Further, RASA will continue to work closely with other organizations, including but not limited to the Electric Power Research Institute (EPRI), the Department of Energy (DOE), the Institute of Electrical and Electronic Engineers (IEEE), the Institute of Nuclear Power Operations (INPO), the North American Transmission Forum (NATF), the North American Generation Forum (NAGF), and the Canadian Electricity Association (CEA). RASA collaborates with these groups on a number of fronts, including geomagnetic disturbance (GMD), vegetation management, and variable generation integration. RASA will continue working with the Interstate Natural Gas Association of America (INGAA) and the Natural Gas Supply Association (NGSA) regarding studies pertaining to the interdependency of gas and electric systems.

2017 Goals and Deliverables

In 2017, RASA will seek to achieve several specific goals and objectives as part of the strategic focus of the ERO Enterprise (Goal 4a):

1. Pioneer implementation of advanced reliability assessment and system analysis methods to address the changing nature of the grid. Issue reliability assessment reports, guidelines, and recommendations to address high priority evolving performance trends and address emerging risks to reliability.
   a. Expand the use of probabilistic assessment tools across the ERO and gain consistency in approach
   b. Special assessments on identified high-priority risks (from RISC prioritization and recommendations)[27]
      - Changing resource mix and maintaining Essential Reliability Services

27 http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Recommendations_to_the_Board.pdf

- Increased penetration of Distributed Energy Resources
- Increasing dependency on generation fueled by natural gas
- Broaden understanding of inter-area and local system oscillations in all interconnections and their potential impact on interconnection reliability.

c. As part of its oversight of the Regional Entities, build and sustain an Enterprise RAPA team (ERO-RAPA) that encompasses the consistent development and implementation of risk-informed approaches and structured methods to identify and address reliability risks.

2. Provide the basis for industry to meet regulatory requirements of the NERC Reliability Standard BAL-003-1, "Frequency Response and Frequency Bias Setting;" exploratory understanding of frequency response; support interconnection-wide studies of frequency response
   a. Frequency Response Annual Analysis and BAL-003 FERC filing
   b. Determination of Interconnection Frequency Response Obligation (IFRO) and BA FRO values
3. Support NERC Reliability Standard development by providing subject matter expertise.
4. Provide support and leadership to (1) the Planning Committee and (2) standing committees' subcommittees, working groups, and task forces serving the standing committees. Support the development of technical reference documents and Reliability Guidelines with support of the PC leadership and established in the annual PC work plan
5. As necessary, support major event investigations, analyses, and reporting of findings, recommendations, and lessons learned to improve reliability.
6. Provide feedback to interconnection-wide model-building groups on improvements to system model quality and fidelity.
7. Assist in the development of approaches to registration and provide input to NERC staff in support of the development CMEP risk elements, as well as support and lead the BES Definition Exception Process.

Resource Requirements

Personnel
Additional personnel were allocated to RASA in 2016 to address increased resource demands associated with ongoing reliability assessment, performance analysis, and system analysis activities.

Contractor Expenses
The total contractor and consultant expenses for the department are projected at $525k, a decrease of $50k from the 2016 budget. Further information is provided on Exhibit C.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
RELIABILITY ASSESSMENTS and SYSTEM ANALYSIS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 6,135,872	$ 6,135,872	0	$ 7,339,030	$ 1,203,158	$ 7,354,185	$ (15,154)
Penalty Sanctions	142,718	142,718		131,213	(11,505)	130,180	1,033
Total NERC Funding	**$ 6,278,590**	**$ 6,278,590**	**$ 0**	**$ 7,470,243**	**$ 1,191,653**	**$ 7,484,364**	**$ (14,121)**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	50,000	-	(50,000)	50,000	-	50,000	-
Workshops	15,000	15,000	-	15,000	-	15,000	-
Interest	462	3,634	3,172	351	(111)	348	3
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 6,344,052**	**$ 6,297,224**	**$ (46,828)**	**$ 7,535,594**	**$ 1,191,542**	**$ 7,549,713**	**$ (14,119)**
Expenses							
Personnel Expenses							
Salaries	$ 1,826,951	$ 2,080,813	$ 253,862	$ 2,247,826	$ 420,875	$ 2,258,124	(10,298)
Payroll Taxes	122,096	137,089	14,993	142,919	20,823	148,547	(5,628)
Benefits	213,866	240,723	26,857	263,230	49,364	269,401	(6,171)
Retirement Costs	203,274	229,385	26,111	246,609	43,335	251,613	(5,003)
Total Personnel Expenses	**$ 2,366,187**	**$ 2,688,010**	**$ 321,823**	**$ 2,900,585**	**$ 534,398**	**$ 2,927,684**	**(27,100)**
Meeting Expenses							
Meetings	$ 109,000	$ 109,000	$ -	$ 74,000	$ (35,000)	$ 109,000	(35,000)
Travel	208,338	249,000	40,662	208,338	-	208,338	-
Conference Calls	17,280	17,280	-	5,270	(12,010)	5,270	-
Total Meeting Expenses	**$ 334,618**	**$ 375,280**	**$ 40,662**	**$ 287,608**	**$ (47,010)**	**$ 322,608**	**(35,000)**
Operating Expenses							
Consultants & Contracts	$ 575,000	$ 442,425	$ (132,575)	$ 525,000	$ (50,000)	$ 525,000	-
Office Rent	-	-	-	-	-	-	-
Office Costs	116,266	138,523	22,257	147,652	31,386	130,283	17,368
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	386,024	282,034	(103,991)	125,621	(260,403)	125,621	-
Total Operating Expenses	**$ 1,077,790**	**$ 863,482**	**$ (214,308)**	**$ 798,773**	**$ (279,018)**	**$ 781,404**	**$ 17,368**
Total Direct Expenses	**$ 3,778,595**	**$ 3,926,772**	**$ 148,177**	**$ 3,986,965**	**$ 208,370**	**$ 4,031,697**	**$ (44,731)**
Indirect Expenses	**$ 2,768,236**	**$ 3,218,866**	**$ 450,630**	**$ 3,435,846**	**$ 667,610**	**$ 3,395,468**	**$ 40,378**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 6,546,832**	**$ 7,145,638**	**$ 598,806**	**$ 7,422,812**	**$ 875,980**	**$ 7,427,165**	**$ (4,354)**
Change in Assets	**$ (202,780)**	**$ (848,413)**	**$ (645,634)**	**$ 112,782**	**$ 315,562**	**$ 122,547**	**(9,765)**
Fixed Assets							
Depreciation	(386,024)	(282,034)	103,991	(125,621)	260,403	(125,621)	-
Computer & Software CapEx	-	53,580	53,580	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 183,316	$ 167,231	$ (16,084)	238,403	$ 55,088	$ 248,168	(9,765)
Inc(Dec) in Fixed Assets (C)	**$ (202,709)**	**$ (61,222)**	**$ 141,486**	**$ 112,782**	**$ 315,491**	**$ 122,547**	**$ -**
TOTAL BUDGET (=B + C)	**$ 6,344,123**	**$ 7,084,415**	**$ 740,292**	**$ 7,535,594**	**$ 1,191,471**	**$ 7,549,713**	**$ (14,119)**
FTEs	**11.75**	**13.19**	**1.44**	**14.10**	**2.35**	**14.13**	**(0.03)**

Performance Analysis

Performance Analysis (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	6.92	9.40	2.49	9.42	(0.02)
Direct Expenses	$ 1,838,245	$ 2,459,356	$ 621,111	$ 2,460,815	$ (1,459)
Indirect Expenses	1,628,513	2,290,564	662,051	2,263,646	26,918
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	107,841	158,936	51,095	165,446	(6,510)
TOTAL BUDGET	$ 3,574,599	$ 4,908,855	$ 1,334,256	$ 4,889,906	$ 18,949

Background and Scope

The Performance Analysis (PA) group provides insight and guidance about reliability risks and areas of concern based on analysis of historic system performance. This includes identifying potential risks of concern related to system, equipment, entity, and organizational performance that may indicate a need to develop remediation strategies, action plans, or data used to create, revise or retire reliability standards or consider new reliability standards. The department focuses on developing a technical framework and understanding the reliability risks facing the industry.

Stakeholder Engagement and Benefit

The ERO monitors the reliability performance of the BES in North America through data gathered to analyze historic trends. The ERO provides reports and recommendations regarding the anticipated conditions that could impact the reliability, security, and stability of the BPS to the industry, Regional Entities, regulatory entities, and other designated entities.

The ERO works with industry leaders to create a reliability strategy that is relevant, timely, and effective at addressing the most important reliability risks. This effort includes PA's contribution (both in data gathering and in statistical analysis of data, trends, and events) toward the ERO's understanding key information identified through analysis and assessment efforts; extracting and prioritizing the associated reliability risks from that information; sharing and integrating those risk analysis insights across the ERO Enterprise; and translating that knowledge into actionable guidance and recommendations for NERC management, the Board, and entities, and state, federal, and provincial policy makers. This offers stakeholders an open and transparent approach for the development of NERC's reliability strategy, ultimately ensuring the ERO is accountable to industry, regulators, and the public at large.

Key Efforts Underway

Performance Analysis collects transmission outage, generator performance, demand response, and protection and control misoperation data in a common format using the various industry databases. This data is used to develop and report on grid metrics that analyze outage frequency, duration, causes, and many other factors related to transmission and generator performance as well as automatic power system protection and control effectiveness. In addition to collecting simple equipment availability, detailed information about individual outage events is collected that, when analyzed at the regional and NERC levels, provides data that may be used to improve BES reliability.

The key trends, findings, and recommendations from Performance Analysis serve as technical input to the ERO's reliability standards and standards project prioritization, compliance process improvements, event analyses, reliability assessment, and critical infrastructure protection efforts. This analysis of BES performance provides an industry reference for historical BES reliability, but it also offers analytical

insights that lead toward the prioritization of specific actionable risk control steps for industry. These analyses and results are summarized in the annual state of reliability report, which provides guidance and recommendations for enhanced bulk system reliability. By January, 2017, PA will add GADS Wind Data to the data collected under Section 1600, requiring the development of a new software tool to enable this.

Performance Analysis is working with Event Analysis to develop a link between their databases. Specific equipment outages will be linked to disturbance reports filed with NERC, enabling better association of transmission and generation outages. The continued alignment between these efforts is expected to enhance the ability to conduct effective event analyses as well as identify key reliability areas for trend analyses of multiple databases. This is expected to improve the depth of event analyses across the ERO Enterprise and expand the quality of data gathered for sophisticated statistical and probabilistic analyses. This will lead to trends and insights about reliability performance, as well as effective measures and actions to address reliability risks. Further in 2016, PA has begun data mining of completed EA efforts to see if any insight might be gained from these events as the grid evolves that were not front and foremost or particularly relevant to enhanced grid reliability at the time of the original event investigation.

Performance Analysis is currently refining the composition of NERC's annual state of reliability (SOR) report to expand the GADS data trend analysis, and for 2017 begin to reflect post-seasonal reliability review, insights from analysis of transmission, generator, and demand response data systems (TADS, GADS, and DADS), and integration of event analysis and misoperations. Also, in 2016, the department will perform activities necessary to determine whether in 2017 the SOR should move from a calendar year (Q1-Q4) report to a fiscal year (2016,Q4-2017,Q3) report.

Further, Performance Analysis will continue to work closely with other organizations, including but not limited to the Electric Power Research Institute (EPRI), the Department of Energy (DOE), the Institute of Electrical and Electronic Engineers (IEEE), the Institute of Nuclear Power Operations (INPO), the North American Transmission Forum (NATF), the North American Generation Forum (NAGF), and the Canadian Electricity Association (CEA). PA collaborates with these groups on a number of fronts, including TADS, GADS, and DADS.

2017 Goals and Deliverables

In 2017, Performance Analysis has a number of specific goals and deliverables in support of the Strategic Plan, including:

1. Issue the state of reliability report, guidelines, recommendations, alerts as needed (including the verification and validation of data and information through Regional Entities and technical committees as required)
2. Oversee and evaluate reliability trends that identify reliability risks by analyzing data contained in NERC's the Generating, Transmission, and Demand Response Availability Data Systems (GADS, TADS, and DADS), along with reliability metrics and protection & controls system misoperations.
3. Support NERC Reliability Standard development by providing subject matter expertise.
4. Provide support and leadership to the standing committees' subcommittees, working groups, and task forces serving the standing committees (primary focus on the Performance Analysis Subcommittee and its subgroups.
5. Assist in the development of approaches to registration and provide input to NERC staff in support of the development of CMEP risk elements
6. Conduct major event investigations, analyses, and reporting of major findings, recommendations, and lessons learned that will improve reliability.

7. Provide insight on emerging system protection issues, and hand-off any issues gleaned with future implications to RASA.

Resource Requirements

Personnel

During 2016 additional personnel (including open positions) were allocated to Performance Analysis to address increased resource demands associated with ongoing reliability assessment, performance analysis, and system analysis activities.

Contractor Expenses

Performance Analysis contractor and consultant expenses are $528k, an increase of $19k over 2016. Additional details are provided in Exhibit C.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
PERFORMANCE ANALYSIS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 3,490,625	$ 3,490,625	$ -	$ 4,821,146	$ 1,330,521	$ 4,802,887	$ 18,259
Penalty Sanctions	84,052	84,051		87,475	3,423	86,786	689
Total NERC Funding	**$ 3,574,677**	**$ 3,574,676**	**$ -**	**$ 4,908,621**	**$ 1,333,944**	**$ 4,889,674**	**$ 18,948**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	50,000	50,000	-	-	-	-
Workshops		-	-	-	-	-	-
Interest		2,554	2,554	234	234	232	2
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 3,574,677**	**$ 3,627,230**	**$ 52,554**	**$ 4,908,855**	**$ 1,334,178**	**$ 4,889,906**	**$ 18,949**
Expenses							
Personnel Expenses							
Salaries	$ 886,643	$ 1,280,436	$ 393,793	$ 1,349,579	$ 462,936	$ 1,341,820	7,760
Payroll Taxes	65,373	90,958	25,585	92,093	26,720	95,140	(3,048)
Benefits	126,252	142,204	15,952	143,104	16,852	154,659	(11,556)
Retirement Costs	98,314	144,446	46,132	149,018	50,704	151,902	(2,885)
Total Personnel Expenses	**$ 1,176,582**	**$ 1,658,044**	**$ 481,462**	**$ 1,733,794**	**$ 557,212**	**$ 1,743,522**	**(9,728)**
Meeting Expenses							
Meetings	$ 1,000	$ 6,000	$ 5,000	$ 1,000	$ -	$ 1,000	-
Travel	118,172	98,000	(20,172)	118,172	-	118,172	-
Conference Calls	9,720	7,000	(2,720)	2,965	(6,755)	2,965	-
Total Meeting Expenses	**$ 128,892**	**$ 111,000**	**$ (17,892)**	**$ 122,137**	**$ (6,755)**	**$ 122,137**	**-**
Operating Expenses							
Consultants & Contracts	$ 509,039	$ 621,849	$ 112,810	$ 528,082	$ 19,043	$ 546,082	(18,000)
Office Rent	-	-	-	-	-	-	-
Office Costs	23,732	51,194	27,462	74,843	51,111	48,574	26,269
Professional Services	-	-	-	-	-	-	-
Miscellaneous		-	-	500	500	500	-
Depreciation		-	-	-	-	-	-
Total Operating Expenses	**$ 532,771**	**$ 673,043**	**$ 140,272**	**$ 603,426**	**$ 70,655**	**$ 595,156**	**$ 8,269**
Total Direct Expenses	**$ 1,838,245**	**$ 2,442,087**	**$ 603,842**	**$ 2,459,356**	**$ 621,111**	**$ 2,460,815**	**$ (1,459)**
Indirect Expenses	**$ 1,628,513**	**$ 2,242,712**	**$ 614,200**	**$ 2,290,564**	**$ 662,051**	**$ 2,263,646**	**$ 26,918**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 3,466,758**	**$ 4,684,799**	**$ 1,218,041**	**$ 4,749,920**	**$ 1,283,162**	**$ 4,724,460**	**$ 25,459**
Change in Assets	**$ 107,919**	**$ (1,057,569)**	**$ (1,165,487)**	**$ 158,936**	**$ 51,016**	**$ 165,446**	**(6,510)**
Fixed Assets							
Depreciation		-	-	-	-	-	-
Computer & Software CapEx	-	162,500	162,500	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 107,841	$ 116,517	$ 8,676	158,936	$ 51,095	$ 165,446	(6,510)
Inc(Dec) in Fixed Assets (C)	**$ 107,841**	**$ 279,017**	**$ 171,176**	**$ 158,936**	**$ 51,095**	**$ 165,446**	**$ -**
TOTAL BUDGET (=B + C)	**$ 3,574,599**	**$ 4,963,816**	**$ 1,389,217**	**$ 4,908,855**	**$ 1,334,257**	**$ 4,889,906**	**$ 18,949**
FTEs	**6.92**	**9.19**	**2.28**	**9.40**	**2.49**	**9.42**	**(0.02)**

Reliability Risk Management

NERC's Reliability Risk Management (RRM) group carries out the ERO's statutory responsibility to perform assessments (real time or near real time continual awareness, detailed analysis of significant events, and longer-tern broad performance assessments) of the reliability and adequacy of the BES, including identifying potential issues of concern relating to system, equipment, entity, and human performance that may indicate the need to develop and implement targeted interventions. RRM has three departments: Situation Awareness (also referred to as Bulk Power System Awareness), Event Analysis, and Performance Analysis, as described above beginning on page 53. These departments are responsible for six primary functions: (1) BES awareness; (2) event analysis and determination of root and contributing causes; (3) assessment of human performance challenges that affect BES reliability and identification of improvement opportunities; (4) continent-wide analysis and reporting of BES performance; (5) support of the NERC Operating Committee; and (6) support of the NERC Critical Infrastructure Protection Committee.

RRM's functions and resources are directly focused on proactive awareness of BES conditions and all events over a threshold of certain risk or impact. Through awareness and continuous assessment, RRM identifies potential reliability risks to the BES. RRM analyzes events in detail, addresses the most significant risks to BES reliability, and ensures that industry is well informed of system events, emerging trends, risk analysis, and lessons learned. Through performing these functions, RRM provides data and analysis to inform the other aspects of NERC's statutory functions. The group also provides strategic direction for using risk-based concepts in planning and executing its responsibilities.

Situation Awareness

Situation Awareness (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget - Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	5.53	5.64	0.11	5.65	(0.01)
Direct Expenses	$ 2,310,875	$ 2,570,828	$ 259,953	$ 2,509,043	$ 61,785
Indirect Expenses	1,302,775	1,374,338	71,563	1,358,187	16,151
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	78,547	87,695	9,148	91,601	(3,906)
TOTAL BUDGET	$ 3,692,197	$ 4,032,862	$ 340,664	$ 3,958,831	$ 74,030

Background and Scope

NERC's Situation Awareness department and the eight Regional Entities monitor BES conditions, significant occurrences and emerging risks, and threats across the 14 Reliability Coordinator regions in North America to maintain an understanding of conditions and situations that could impact the bulk electric system's reliable operation. This group also supports the development and publication of Alerts and awareness products and facilitates information sharing among industry, Regions, and the government during crisis situations and major system disturbances. The process for understanding the potential threats or vulnerabilities to the reliability of the BPS starts with understanding occurrences and events in the context in which they occur.

Stakeholder Engagement and Benefit

BES conditions continually change and provide recognizable signatures through automated tools, mandatory reports and voluntary information sharing, and third-party publicly available sources. The significant majority of these signatures represents conditions and occurrences that have little or no

reliability impact, either positive or adverse, on the BES. However, being cognizant of the short-term condition of the BES and the signatures associated with the entire range of reliability performance helps the ERO identify significant occurrences and events more accurately and efficiently. Registered entities continue to robustly share information and collaborate with the ERO in an effort to maintain and improve the overall reliability of the grid.

Key Efforts Underway

Several reliability-related situation awareness and monitoring tools will undergo enhancement, replacement, streamlining, or modification. The following tools are being focused on during 2016: (1) operation and maintenance of Situation Awareness for NERC, FERC, and Regions, Version 2 (SAFNRv2) software application used for monitoring, to include preparation for a new RFP process in late 2016 to enhance the tool from its current state with no changes to the data used; (2) operation and maintenance of the current secure NERC Alerts tool while planning for a streamlined NERC Alert process and platform appropriately integrated with related ongoing NERC, E-ISAC and ERO Enterprise IT initiatives; (3) refresh of the Reliability Coordinator Information System (RCIS) legacy application for operability and maintainability reasons, with no significant changes to functionality; and (4) continuing to set the conditions to bring limited streaming Synchrophasor data into NERC for wide-area situational awareness and event triage applications.

2017 Goals and Deliverables

In 2017, the Situation Awareness department will seek to accomplish the following specific goals and deliverables:

1. Ensure that the ERO is aware of all BES events above a threshold of impact.
2. Enable the sharing of information and data to facilitate wide-area situational awareness.
3. During crisis situations, facilitate the exchange of information among industry, Regions, and the U.S. and Canadian governments.
4. Keep industry informed of emerging reliability threats and risks to the BES, including any expected actions.
5. Conduct the annual NERC Monitoring and Situational Awareness Conference and Human Performance Conference.
6. Administer the NERC Alerts process as specified in ROP §810 to issue Advisory (Level 1) Alerts on significant and emerging reliability- and security-related topics as needed, and facilitate the tracking of actions specified in Recommendation (Level 2) and Essential Action (Level 3) Alerts.

The department uses the following major reliability-related tools to support department activities:

Resource Adequacy (ACE Frequency) Tool

This software application provides continuous monitoring of key resource adequacy performance metrics, including pre-established thresholds and limits defined in standards. It alerts Reliability Coordinators and resource subcommittees to conditions that could result in critical inadequacies, such as major tie errors, inaccurate load forecasts, and inadequate frequency response.

Inadvertent Interchange

This tool facilitates the entering of monthly scheduling data and submittal of monthly inadvertent performance standards reports to NERC. It also assists in the monitoring and resolution of reliability issues originated by inadvertent interchange imbalances.

Frequency Monitoring and Analysis Tool

This tool detects frequency events and captures key frequency response information for each interconnection.

Intelligent Alarms Tool

This tool detects short-term and long-term frequency deviations using data transmitted to NERC by the Balancing Authorities. When coupled with the FNet[28] and Frequency Monitoring and Analysis tools, this tool allows immediate differentiation of the cause of a frequency deviation—a generator trip or a scheduling error.

Genscape

The PowerIQ and PowerRT tools provide more detailed insight into current-day conditions impacting BPS conditions in both normal operations and stressed conditions.

Resource Requirements

Personnel

No additional personnel are projected for the Situation Awareness department in 2017. The slight increase reflected in the following table is due to a lower vacancy rate than in 2016.

Contractor Expenses

The overall funding of approximately $1.3M for contractors and consultants (which includes the cost of the tools set forth above) to support the Situation Awareness department in 2017 represents an increase of $84k over 2016 budget levels. The detailed 2017 contractor and consulting budget for the Situation Awareness department is set forth in Exhibit C with a comparison to 2016 budgeted amounts.

[28] FNet – Operated by the Power Information Technology Laboratory at the University of Tennessee, FNET is a low-cost, quickly deployable global positioning system (GPS)-synchronized wide-area frequency measurement network. High dynamic accuracy Frequency Disturbance Recorders (FDRs) are used to measure the frequency, phase angle, and voltage of the power system at ordinary 120 V outlets. The measurement data are continuously transmitted via the Internet to the FNET servers hosted at the University of Tennessee and Virginia Tech.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
SITUATION AWARENESS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 3,624,868	3,624,868	$ 0	$ 3,980,236	$ 355,369	$ 3,906,620	$ 73,616
Penalty Sanctions	67,193	67,193	0	52,485	(14,708)	52,072	413
Total NERC Funding	**$ 3,692,060**	**$ 3,692,060**	**$ 0**	**$ 4,032,721**	**$ 340,661**	**$ 3,958,692**	**$ 74,029**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	1,128	1,128	-	-	-	-
Interest	137	1,816	1,679	140	3	139	1
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 3,692,197**	**$ 3,695,004**	**$ 2,807**	**$ 4,032,862**	**$ 340,664**	**$ 3,958,831**	**$ 74,030**
Expenses							
Personnel Expenses							
Salaries	$ 764,342	$ 787,436	$ 23,094	$ 873,869	$ 109,527	$ 780,907	92,962
Payroll Taxes	58,235	59,443	1,208	58,749	515	59,423	(674)
Benefits	101,765	135,367	33,601	156,328	54,563	142,213	14,115
Retirement Costs	85,275	88,342	3,067	96,159	10,884	90,776	5,382
Total Personnel Expenses	**$ 1,009,617**	**$ 1,070,587**	**$ 60,971**	**$ 1,185,105**	**$ 175,488**	**$ 1,073,320**	**111,785**
Meeting Expenses							
Meetings	$ 6,500	$ 5,000	$ (1,500)	$ 6,500	$ -	$ 6,500	-
Travel	33,005	32,500	(505)	33,005	-	33,005	-
Conference Calls	1,000	1,000	-	305	(695)	305	-
Total Meeting Expenses	**$ 40,505**	**$ 38,500**	**$ (2,005)**	**$ 39,810**	**$ (695)**	**$ 39,810**	**$ -**
Operating Expenses							
Consultants & Contracts	$ 1,211,475	$ 1,268,777	$ 57,302	$ 1,295,850	$ 84,375	$ 1,345,850	(50,000)
Office Rent	-	-	-	-	-	-	-
Office Costs	41,052	39,540	(1,512)	41,897	845	41,897	-
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	7,727	7,727	-	7,667	(60)	7,667	-
Total Operating Expenses	**$ 1,260,754**	**$ 1,316,544**	**$ 55,790**	**$ 1,345,914**	**$ 85,160**	**$ 1,395,914**	**$ (50,000)**
Total Direct Expenses	**$ 2,310,875**	**$ 2,425,631**	**$ 114,756**	**$ 2,570,828**	**$ 259,953**	**$ 2,509,043**	**$ 61,785**
Indirect Expenses	**$ 1,302,775**	**$ 1,391,019**	**$ 88,243**	**$ 1,374,338**	**$ 71,563**	**$ 1,358,187**	**$ 16,151**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 3,613,650**	**$ 3,816,649**	**$ 202,999**	**$ 3,945,167**	**$ 331,516**	**$ 3,867,230**	**$ 77,936**
Change in Assets	**$ 78,547**	**$ (121,645)**	**$ (200,192)**	**$ 87,695**	**$ 9,148**	**$ 91,601**	**(3,906)**
Fixed Assets							
Depreciation	(7,727)	(7,727)	-	(7,667)	60	(7,667)	-
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 86,273	$ 72,268	(14,005)	95,361	9,088	$ 99,267	(3,906)
Inc(Dec) in Fixed Assets (C)	**$ 78,547**	**$ 64,542**	**$ (14,005)**	**$ 87,695**	**$ 9,148**	**$ 91,601**	**$ -**
TOTAL BUDGET (=B + C)	**$ 3,692,197**	**$ 3,881,191**	**$ 188,994**	**$ 4,032,862**	**$ 340,664**	**$ 3,958,831**	**$ 74,030**
FTEs	**5.53**	**5.70**	**0.17**	**5.64**	**0.11**	**5.65**	**(0.01)**

Event Analysis Department

Event Analysis (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	11.06	11.28	0.22	11.30	(0.02)
Direct Expenses	$ 2,650,065	$ 2,592,388	$ (57,676)	$ 2,686,020	$ (93,631)
Indirect Expenses	2,605,551	2,748,677	143,126	2,716,375	32,302
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	100,179	105,141	4,962	112,953	(7,812)
TOTAL BUDGET	$ 5,355,795	$ 5,446,206	$ 90,411	$ 5,515,347	$ (69,141)

Background and Scope

The Event Analysis department performs assessments of the reliability and adequacy of the BES. This includes identifying potential issues of concern related to system, equipment, entity, and human performance that may indicate a need to develop remediation strategies, action plans, or data used to revise or retire reliability standards or consider new reliability standards. The department analyzes and determines the cause of the events, promptly ensures tracking of corrective actions to prevent recurrence, and provides lessons learned to the industry. Event Analysis ensures that reporting and analysis are consistent to allow wide-area assessment of trends and risks. The department analyzes all reportable events for sequence of events, root cause, risk to reliability, and mitigation and keeps the industry well informed of system events, emerging trends, risk analysis, lessons learned, and expected actions.

Additional resources within this department focus on identifying human-error risks and those precursor factors that allow human error to impact system reliability. The department educates industry regarding risks, precursors, and mitigation methods. Resources also support compliance and standards training initiatives and trending and analysis to identify emerging reliability risks to the BES. These efforts are conducted in collaboration with industry human performance projects, including WECC's Human Performance Working Group, the NERC Operating Committee's Event Analysis Subcommittee, and others.

Stakeholder Engagement and Benefit

The Event Analysis department coordinates event analyses to support the use of collective resources, consistency in analysis, and timely delivery of event analysis reports.[29] The ERO disseminates to the electric industry lessons learned and other useful information obtained from or as a result of event analysis. The Event Analysis team conducts in-depth analyses of approximately 150 events per year on average. In 2014, the team also conducted calls facilitated by the Regional Entities with over 140 registered entities to discuss in detail and finalize root and contributing causes for the categorized events analyzed. Major analysis to date includes continuing assessment of Energy Management System (EMS) outages, continued collaboration with Reliability Assessments and System Analysis on frequency response performance, analyses of substation equipment failure events and protective relay trends including ground overcurrent relay misoperations, relay communication system failures, and the importance of commissioning testing.

Collaboration with the Trade Associations and Forums

The activities of the NATF, the NAGF, trade associations, and other industry groups are expected to compliment ERO Enterprise activities and limit the need to add incremental resources to the NERC and

[29] The core process for Event Analysis is outlined in the approved process: Electric Reliability Organization Event Analysis Process - Version 3 (January 2016).

Regional Entity business plans and budgets that might otherwise be required in the absence of these forums.

NERC is supporting the NAGF's ongoing transformation into a more formal structure through 2017 and continuing through 2018 with logistical and administrative support.

NATF has been invited to participate in several reliability initiatives that are expected to continue into 2017, including protection systems misoperations reduction, physical security, various activities related to reliability assurance initiatives, improvement of modeling practices, and complementary efforts on addressing the GMD challenges.

2017 Goals and Deliverables

In 2017, the Event Analysis department will seek to accomplish several specific goals and objectives as part of the strategic focus of the ERO Enterprise:

- Work with the Regional Entities to obtain and review information from registered entities on qualifying events and disturbances to advance awareness of events above a threshold level; facilitate analysis of root and contributing causes, risks to reliability, wide-area assessments, and remediation efforts; and disseminate information regarding events in a timely manner.
- Ensure that all reportable events are analyzed for sequence of events, root cause, risk to reliability, and mitigation.
- Continue to refine risk-based methods to support better identification of reliability risks, including the use of more sophisticated cause codes for analysis.
- Conduct training (webinars, workshops, and conference support) to inform industry and the ERO of lessons learned, root cause analysis, trends, human performance, and extreme weather preparedness and recommendations.
- Develop reliability recommendations and alerts as needed and track industry accountability for critical reliability recommendations.
- Ensure that industry is well informed of system events, emerging trends, risk analysis, lessons learned, and expected actions.
- Conduct major event analysis and reporting of major findings and recommendations that will improve reliability.

The Event Analysis department will also support several of the top-priority reliability risk projects during 2017 through 2018, as identified and described under the Performance Analysis department section of this document.

Resource Requirements

Personnel

The slight increase in FTEs budgeted in the Event Analysis department in 2017 is due to a lower vacancy rate than in 2016.

Contractor Expenses

No contractor expenses are budgeted in 2017.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
EVENT ANALYSIS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 5,181,136	$ 5,181,136	$ 0	$ 5,300,955	$ 119,819	$ 5,370,925	$ (69,970)
Penalty Sanctions	134,385	$ 134,385		104,970	(29,415)	104,144	826
Total NERC Funding	**$ 5,315,521**	**$ 5,315,521**	**$ 0**	**$ 5,405,926**	**$ 90,404**	**$ 5,475,069**	**$ (69,143)**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	40,000	78,073	38,073	40,000	-	40,000	-
Interest	274	2,918	2,644	281	7	279	2
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 5,355,795**	**$ 5,396,512**	**$ 40,717**	**$ 5,446,206**	**$ 90,411**	**$ 5,515,347**	**$ (69,141)**
Expenses							
Personnel Expenses							
Salaries	$ 1,716,263	$ 1,617,447	$ (98,817)	$ 1,708,049	$ (8,214)	$ 1,778,729	(70,680)
Payroll Taxes	114,132	$ 110,186	(3,946)	108,739	(5,393)	117,316	(8,577)
Benefits	202,259	$ 183,405	(18,853)	212,232	9,973	213,883	(1,651)
Retirement Costs	191,377	$ 180,295	(11,082)	189,397	(1,980)	202,216	(12,819)
Total Personnel Expenses	**$ 2,224,030**	**$ 2,091,333**	**$ (132,698)**	**$ 2,218,416**	**$ (5,614)**	**$ 2,312,144**	**(93,727)**
Meeting Expenses							
Meetings	$ 81,500	$ 140,000	$ 58,500	$ 81,500	$ -	$ 81,500	-
Travel	152,487	152,000	(487)	152,487	-	152,487	-
Conference Calls	14,000	14,000	-	4,270	(9,730)	4,270	-
Total Meeting Expenses	**$ 247,987**	**$ 306,000**	**$ 58,013**	**$ 238,257**	**$ (9,730)**	**$ 238,257**	**-**
Operating Expenses							
Consultants & Contracts	$ 56,000	$ 56,000	$ -	$ -	$ (56,000)	$ -	-
Office Rent	-	-	-	-	-	-	-
Office Costs	49,181	53,576	4,395	49,634	452	49,538	96
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	72,367	85,582	13,214	85,582	13,214	85,582	-
Total Operating Expenses	**$ 178,048**	**$ 195,658**	**$ 17,609**	**$ 135,715**	**$ (42,333)**	**$ 135,619**	**$ 96**
Total Direct Expenses	**$ 2,650,065**	**$ 2,592,990**	**$ (57,075)**	**$ 2,592,388**	**$ (57,677)**	**$ 2,686,020**	**$ (93,631)**
Indirect Expenses	**$ 2,605,551**	**$ 2,511,155**	**$ (94,396)**	**$ 2,748,677**	**$ 143,126**	**$ 2,716,375**	**$ 32,302**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 5,255,616**	**$ 5,104,145**	**$ (151,471)**	**$ 5,341,065**	**$ 85,449**	**$ 5,402,394**	**$ (61,329)**
Change in Assets	**$ 100,179**	**$ 292,367**	**$ 192,188**	**$ 105,141**	**$ 4,962**	**$ 112,953**	**(7,812)**
Fixed Assets							
Depreciation	(72,367)	(85,582)	(13,214)	(85,582)	(13,214)	(85,582)	-
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 172,546	$ 130,463	(42,083)	190,723	18,176	$ 198,535	(7,812)
Inc(Dec) in Fixed Assets (C)	**$ 100,179**	**$ 44,881**	**$ (55,298)**	**$ 105,141**	**$ 4,962**	**$ 112,953**	**$ (7,812)**
TOTAL BUDGET (=B + C)	**$ 5,355,795**	**$ 5,149,026**	**$ (206,769)**	**$ 5,446,206**	**$ 90,411**	**$ 5,515,347**	**$ (69,141)**
FTEs	**11.06**	**10.29**	**(0.77)**	**11.28**	**0.22**	**11.30**	**(0.02)**

Electricity Information Sharing and Analysis Center (E-ISAC)[30]

E-ISAC (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget - Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	18.90	19.74	0.84	19.78	(0.04)
Direct Expenses	$ 11,965,349	$ 12,276,689	$ 311,340	$ 12,501,721	$ (225,032)
Indirect Expenses	4,450,914	4,810,185	359,271	4,753,175	57,009
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	351,262	1,428,467	1,077,205	442,103	986,364
TOTAL BUDGET	$ 16,767,525	$ 18,515,341	$ 1,747,816	$ 17,696,999	$ 818,342

Background and Scope

The Electricity Sector Information Sharing and Analysis Center (ES-ISAC) was formed in 1998 when the U.S. Secretary of Energy requested that NERC serve as the ISAC[31] for the Electricity Subsector.[32] This department was rebranded to the Electricity Information Sharing and Analysis Center (E-ISAC) in September 2015. The E-ISAC reduces cyber and physical risk to the Electricity Subsector across North America by providing unique insights, leadership, and coordination. The vision is to be the trusted, timely, actionable resource of grid risk information and analysis to enhance electricity reliability. The E-ISAC facilitates Electricity Subsector and cross-sector coordination regarding physical security and cybersecurity events affecting the BES.

Maintaining Separation from Compliance and Enforcement

Starting in February 2012, the Board of Trustees approved an E-ISAC Policy Statement that established a separation between the E-ISAC and NERC's compliance and enforcement program. In 2015, physical separation of the E-ISAC was completed. The company also has in place an E-ISAC Code of Conduct and Policy on the Role of the E-ISAC vis-à-vis NERC's Compliance Monitoring and Enforcement Program.

Key Efforts Underway

With industry support, in coordination with the Electricity Subsector Coordinating Council (ESCC) and its Member Executive Committee (MEC), senior management is committed to enhancing the effectiveness and capabilities of E-ISAC operations. These efforts include ongoing enhancement in organizational structure, operational and analytical capabilities, as well as the development of metrics to track the effectiveness of operations. Management will also take steps to improve the quality and value of E-ISAC products, including ongoing review of registered user needs.

During 2015, as part of a periodic review of companywide resource needs and resource allocation, NERC allocated additional resources to support the E-ISAC. Management recruited personnel to fill open positions, and recruited and appointed a senior vice president and chief security officer in charge of E-ISAC operations. Ongoing resource requirements consist primarily of personnel, contractors, consultants,

[30] In 2015, NERC combined its Critical Infrastructure Department (CID) into the E-ISAC for both operational and financial reporting purposes.

[31] The Information Security Analysis Center (ISAC) construct was conceived and operates under US Government authorities derived from Presidential Decision Directive 63, which was signed in 1998. The ISACs focus specifically on information sharing, analytics and sector activities directly related to the protection of critical infrastructure.

[32] Subsequent administrations have sought to continue and strengthen information sharing in other sectors by establishing other sector-specific ISACs. In 2013, the Department of Energy (DOE) again reaffirmed its desire for NERC to continue to operate the E-ISAC.

software, hardware and communications infrastructure to gather, analyze, and provide information regarding cyber and physical security threats.

In the fourth quarter of 2014 and with broad industry support, NERC also assumed management responsibility for the Cybersecurity Risk Information Sharing Program (CRISP). CRISP is a public-private partnership whose purpose is to facilitate the sharing of cyber threat information and to develop situation awareness tools that enhance the electricity sector's ability to identify, prioritize, and coordinate the protection of its critical infrastructure. CRISP provides critical infrastructure owners and operators the capability to voluntarily share cyber threat data, analyze this data, and receive machine-to-machine mitigation measures. Information-sharing devices that are installed on participants' networks send encrypted data to a CRISP analysis center operated by the Pacific Northwest National Labs (PNNL), which analyzes the data it receives and sends alerts and mitigation measures back to CRISP participants and the E-ISAC through secure communications. CRISP became fully operational in 2015. The E-ISAC will continue to work with PNNL, CRISP participants and E-ISAC registered users to strengthen program execution, including both quality and timeliness aspects of information sharing. The 2017 E-ISAC budget maintains the same percentage allocation of CRISP funding requirements from assessments and from CRISP participants as 2016. In connection with the growth of the program and related support needs from E-ISAC staff, the 2017 E-ISAC budget also reflects an increase in the number of budgeted E-ISAC FTEs allocated to support CRISP.

Resource Requirements

Personnel

As previously noted, in 2016 additional open budgeted resources were re-allocated to provide support to the E-ISAC[33], resulting in a net increase of 0.84 FTEs.

The E-ISAC staffing and organizational structure has recently been updated to reflect four primary focus areas (1) stakeholder engagement, (2) watch operations (3) cyber security analysis, and (4) physical security analysis. NERC's 2017 organization chart attached as Appendix 1 has been updated to reflect these changes and additional personnel on-boarded in 2016. The E-ISAC will continue to receive shared services support from NERC's corporate services departments (i.e. finance and accounting, IT, HR, legal and external affairs). Personnel providing such shared services will do so only in accordance with strict operating protocols governing access to and use of E-ISAC information as noted above.

Contract Expenses

The specific nature and need for contract support for the E-ISAC falls under three major categories: Program Level Support, Software and Services, and Events and Outreach. Each of these categories is discussed further below and Exhibit C sets forth the budget for each of these categories of expense.

Program Level Support

CRISP

During 2016 and 2017 NERC will continue to subcontract to PNNL the majority of the resource requirements and associated costs to operate and maintain CRISP.

E-ISAC Portal Enhancement

The E-ISAC communication portal capabilities include: publishing immediate notifications and other informational products, exchanging threat indicator information, and providing self-service access to user

[33] Departments with reduced staffing needs included the legal, enforcement and standards departments.

security awareness services. The E-ISAC is working with NERC Information Technology (in the lead) to continue development of the portal that was initiated in 2014 as part of a long-term improvement strategy. Important new enhancements and improved capabilities are presently in use and development. These include facilitating direct data exchange with E-ISAC members, other ISACs and government partners, and establishing user communities where individuals can discuss security issues. The portal's improved capabilities support E-ISAC analysts in their information analysis functions and directly tie them with their counterparts in other sectors and national laboratories.

In 2015, the ESCC presented its recommendations resulting from a review of the E-ISAC operations performed that year. These recommendations included a request to evaluate and potentially enhance the user interface and underlying functionality of the E-ISAC portal. In 2015, the ESCC established a Member Executive Committee (MEC) to provide guidance with respect to various E-ISAC matters, including improvements to the E-ISAC portal. As part of an approved 2016 work plan, the E-ISAC staff worked closely with the MEC to develop a business case and funding estimates for these improvements. Additional details summarizing the business case, funding estimate and additional detail regarding the portal improvement project is attached as Exhibit F.

The 2017 E-ISAC budget includes $1M for the portal enhancements ($250,000 of which is allocated to CRISP)[34]. The MEC has provided written comments [found here] in support of this investment.

Additional portal enhancements in 2016 and 2017 will also extend functionality to allow for easier access to filtered data for both the cyber and physical security communities and provide for automated information sharing. Based on input from users, the E-ISAC is transitioning the current portal capability to a platform model that will provide features and extensions beyond what can currently be delivered with the existing portal. Some of the new features will include user customization, visual and graphical orientation (versus text-based), robust search and structured queries, and the ability to create on-the-fly technical analysis of information shared by users. This will be a multi-year project that will evolve as users engage the new capabilities and provide feedback. In 2017 the E-ISAC and NERC IT plan to launch the initial platform prototype with new capabilities, then add capabilities and features in 2018 and subsequent years as needed.

Software and Services

Software Integration Support Services

The E-ISAC operations center includes monitors used to display intelligence information provided from various software applications. Software integration services are routinely required from vendors providing existing and new software applications. Additional software must be licensed and maintained to display and integrate BES maps that have cyber intelligence information. A portion of these costs is budgeted under Office Costs as software maintenance expenses.

Analyst Workbench

A strong technical analytic capability is needed to develop baselines and identify patterns and understandings of potential cyber-related threats. The analyst workbench toolset maintains historical information and allows a team to use and deliver consistent and repeatable analysis in both an operational (during an event) as well as nonoperational capacity. This workbench will include a threat database for historical correlation and various tools for network- and host-based analysis of malicious software.

[34] The annual impact of the proposed $1M investment on assessments will be approximately $250,000 since projects of this nature are typically financed through NERC's capital financing program and funded over a three year period.

Automated Information Sharing

The E-ISAC is broadening automated information sharing beyond CRISP, looking at programs such as the Structured Threat Information Expression/Trusted Automated Exchange of Indicator Information (STIX/TAXII) initiative hosted by the US Department of Homeland Security. As part of a work plan developed in consultation with the MEC, in 2016 the E-ISAC plans to pilot and gather data on these technologies, leveraging existing implementations at Argonne National Lab. The pilot will help the E-ISAC understand the nuances of bi-directional communication, workflow, handling rules, vetting information, and learning from the technology and processes overall. The E-ISAC aims to have seven members signed up by the end of 2016, and, assuming the 2016 pilot is successful, another 10 members sign up in by the end of 2017.

Events and Outreach

Grid Security Exercises

Since 2011, NERC has sponsored a series of biennial grid security exercises (GridEx). These geographically distributed exercises are designed to exercise the electricity sector's crisis response to simulated coordinated cybersecurity and physical security threats and incidents, to strengthen utilities' crisis response functions, and to provide input for lessons learned. GridEx III, in November 2015, consisted of a two-day grid-focused operational exercise for participants across North America and a half-day tabletop discussion for executives. The E-ISAC manages the program and collects industry information during and after the exercise subject to existing data collection policies. During the exercise, E-ISAC watch and analysis staff exercise the E-ISAC mission and share severe crisis information sharing and analysis towards mitigating the threats and attacks. Lessons learned and recommendations are turned over to groups like NERC's Board of Trustees and CIPC and to the ESCC for consideration and coordination between industry and government stakeholders. GridEx IV is scheduled for November 15-16, 2017.

Grid Security Conferences

Since 2011, NERC has sponsored a series of annual grid security conferences (GridSecCon). These conferences bring together industry and government subject matter experts on cyber, physical and operations technology threats and solutions, with training sessions and classified or official use briefs on topics vital to grid security. The E-ISAC provides expertise and gathers appropriate speakers, panelists and training providers. GridSecCon 2016 is scheduled for October 18-21 in Quebec, Canada, with the 2017 location and dates TBD.

Intelligence Reporting Services

E-ISAC analytic personnel maintain a detailed understanding of emerging vulnerabilities and threats within the broad industrial control systems community, as well as within the more focused BES community. To support this intelligence role, the E-ISAC budget includes the costs for intelligence services from a specialized security information service providers that focuses closely on the electricity subsector. This service gives E-ISAC staff increased understanding of continuing trends, breaking news, and implications to the BES, which they utilize to keep registered entities informed of emerging BES risks through immediate notifications and portal security postings.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection and 2017 Budget
E-ISAC

	2016 Budget	2016 Projection	2016 Projection v 2016 Budget Over(Under)	2017 Budget	2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 9,636,756	9,636,756	$ (0)	$ 11,270,705	$ 1,633,948	$ 10,533,578	$ 737,127
Penalty Sanctions	229,563	229,563	0	183,698	(45,865)	182,233	1,465
Total NERC Funding	**$ 9,866,319**	**$ 9,866,319**	**$ (0)**	**$ 11,454,403**	**$ 1,588,084**	**$ 10,715,811**	**$ 738,592**
Third-Party Funding (CRISP)	6,830,738	7,335,757	505,019	6,990,447	159,709	6,910,701	79,746
Workshops	70,000	70,000	-	70,000	-	70,000	-
Interest	468	-	(468)	491	24	487	4
Total Funding (A)	**$ 16,767,525**	**$17,272,076**	**$ 504,551**	**$ 18,515,341**	**$ 1,747,816**	**$ 17,696,999**	**$ 818,342**
Expenses							
Personnel Expenses							
Salaries	$ 3,373,066	$ 3,242,857	$ (130,209)	$ 3,417,398	$ 44,332	$ 3,391,165	$ 26,234
Payroll Taxes	208,610	193,941	(14,668)	204,023	(4,587)	209,345	(5,322)
Benefits	345,260	315,363	(29,897)	397,467	52,207	384,714	12,754
Retirement Costs	366,723	351,531	(15,192)	363,482	(3,241)	372,179	(8,697)
Total Personnel Expenses	**$ 4,293,659**	**$ 4,103,693**	**$ (189,966)**	**$ 4,382,370**	**$ 88,711**	**$ 4,357,402**	**$ 24,968**
Meeting Expenses							
Meetings	$ 230,000	$ 229,000	$ (1,000)	$ 230,000	$ -	$ 230,000	$ -
Travel	256,488	237,455	(19,032)	256,488	-	256,488	-
Conference Calls	22,000	23,000	1,000	6,710	(15,290)	6,710	-
Total Meeting Expenses	**$ 508,488**	**$ 489,455**	**$ (19,032)**	**$ 493,198**	**$ (15,290)**	**$ 493,198**	**$ -**
Operating Expenses							
Consultants & Contracts	$ 6,551,929	$ 7,579,159	$ 1,027,230	$ 6,788,429	$ 236,500	$ 7,038,429	$ (250,000)
Office Rent	-	$ -	-	-	-	-	-
Office Costs	392,285	$ 296,103	(96,182)	431,895	39,610	431,895	-
Professional Services	175,000	$ 175,000	-	175,000	-	175,000	-
Miscellaneous	500	$ 500	-	500	-	500	-
Depreciation	43,489	$ 45,998	2,509	5,297	(38,192)	5,297	-
Total Operating Expenses	**$ 7,163,203**	**$ 8,096,760**	**$ 933,557**	**$ 7,401,121**	**$ 237,919**	**$ 7,651,121**	**$ (250,000)**
Total Direct Expenses	**$ 11,965,349**	**$12,689,908**	**$ 724,559**	**$ 12,276,689**	**$ 311,340**	**$ 12,501,721**	**$ (225,032)**
Indirect Expenses	**$ 4,450,914**	**$ 4,601,898**	**$ 150,984**	**$ 4,810,185**	**$ 359,271**	**$ 4,753,175**	**$ 57,009**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 16,416,263**	**$17,291,806**	**$ 875,543**	**$ 17,086,873**	**$ 670,610**	**$ 17,254,896**	**$ (168,023)**
Change in Assets	**$ 351,262**	**$ (19,730)**	**$ (370,992)**	**$ 1,428,467**	**$ 1,077,205**	**$ 442,103**	**$ 986,364**
Fixed Assets							
Depreciation	(43,489)	(45,998)	(2,509)	(5,297)	38,192	(5,297)	-
Computer & Software CapEx	100,000	111,722	11,722	1,100,000	1,000,000	100,000	1,000,000
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	41,958	41,958	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 294,751	$ 248,373	(46,378)	333,765	39,014	347,401	(13,636)
Inc(Dec) in Fixed Assets (C)	**$ 351,262**	**$ 356,054**	**$ 4,792**	**$ 1,428,467**	**$ 1,077,205**	**$ 442,103**	**$ 986,364**
TOTAL BUDGET (=B + C)	**$ 16,767,525**	**$17,647,860**	**$ 880,335**	**$ 18,515,341**	**$ 1,747,816**	**$ 17,696,999**	**$ 818,342**
FTEs	**18.90**	**18.95**	**0.05**	**19.74**	**0.84**	**19.78**	**(0.04)**

Training, Education, and Operator Certification

Training, Education and Operator Certification (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	7.38	7.05	(0.33)	7.07	(0.01)
Direct Expenses	$ 2,062,086	$ 1,922,295	$ (139,791)	$ 1,889,814	$ 32,481
Indirect Expenses	1,737,034	1,717,923	(19,111)	1,697,734	20,189
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	113,112	117,283	4,171	122,165	(4,882)
TOTAL BUDGET	$ 3,912,231	$ 3,757,501	$ (154,731)	$ 3,709,713	$ 47,788

Background and Scope

NERC's Training and Education Program provides oversight and coordination of the delivery of training programs that support the ERO's statutory responsibilities. This program provides training to NERC and Regional Entity staff members. It also provides training and education to industry participants on the requirements of reliability standards and the compliance monitoring and enforcement process. Further, this program provides training to industry participants on NERC's reliability standards development process, thereby helping to support the more efficient and effective development of mandatory reliability standards. The Training and Education Program supports NERC's responsibilities to develop, adopt, and obtain approval of reliability standards and to monitor, enforce, and achieve compliance with the mandatory standards. Section 901 of the NERC Rules of Procedure addresses the Training and Education Program's activities. The responsibility for training is shared among multiple departments at NERC.[35]

NERC's System Operator Certification program, which ensure that personnel operating the BES have the skills, training, and qualifications needed to operate the system reliably. NERC maintains the required credentials for over 6,000 system operators to work in system control centers across North America. NERC's system operator certification exam is designed to test specific knowledge of job skills and reliability standards. It also prepares operators for complying with requirements of reliability standards and appropriately operating the BES during normal and emergency operations. The System Operator Certification Program is governed by the Personnel Certification Governance Committee (PCGC), an industry group of operations experts, trainers, and supervisors. Certification exams are created by the Exam Working Group (EWG), an industry group of operations subject matter experts. Under the PCGC oversight, the EWG reviews and updates job tasks and certification exams. Section 600 of the NERC Rules of Procedure addresses the Personnel Certification activities in the area of Operator Certification.

Once an operator passes the certification exam, certification is maintained by completing NERC-approved continuing education courses and activities. The Personnel Subcommittee, composed of industry training experts, provides oversight of the Continuing Education program. Section 902 of the NERC Rules of Procedure addresses the Continuing Education Program's activities in these areas.

Key Efforts Underway

The ERO provides education for industry and ERO Enterprise staff personnel to support their understanding of key program areas. These areas include:

[35] The Human Resources department is also engaged in training initiatives.

1. Risk-Based Compliance Monitoring and Enforcement
2. Standards and Compliance
3. Registration and Certification
4. Event Analysis, Cause Analysis, and Lessons Learned
5. Reliability Assessment and System Analysis
6. Continuing education for system operators
7. New System Operator Certification exams for each credential: Reliability Coordinator; Transmission Operator; Balancing and Interchange Operator; and Balancing, Interchange and Transmission Operator.

2017 Goals and Deliverables

In response to stakeholder and Regional Entity feedback, training and education opportunities will be further expanded and focused for registered entities, NERC staff, and Regional Entities. For registered entities, this training and education will focus on objectives related to NERC reliability standards, including standards compliance and emerging cyber-related issues that could affect BES reliability. For NERC and Regional Entity staff, the training and education will focus on consistent audit and investigation techniques and standards compliance reviews, including the risk-based compliance monitoring and enforcement and other improvements in compliance and enforcement practices. NERC will continue to offer training in auditor skills to promote continued development of auditing expertise. NERC will leverage IT systems to better deliver and share common training products and information with Regional Entities and registered entities. Other training will focus on knowledge and skill development in a number of key areas, including:

- Development and implementation of clear and technically sound reliability standards
- Key lessons learned and trends from events
- Identified themes from trending and common-cause analyses
- Effective compliance cultures with practices, procedures, and controls to address reliability risks
- Effective root, apparent, and common-cause analysis methods
- Quality improvement of registered entity self-reporting and self-certification
- Entity registration processes, issues, and alternatives
- Human performance fundamentals
- Developing and incorporating a systematic approach to ongoing training

NERC will continue to provide learning opportunities through workshops hosted by the Regional Entities. NERC will also host workshops, webinars, and training courses, as well as use vendors to develop training modules and supplement internal training resources. The responsibility for the subject matter expertise for much of the training is shared among multiple departments at NERC. The Training and Education group will provide coordination and synchronization efforts for shared NERC and ERO training responsibilities in addition to advancing and improving the skills of NERC's operating staff. NERC's Human Resources department will continue to budget and manage the delivery of more traditional corporate employee training and continuing education programs in concert with the coordination and synchronizing efforts of the Training and Education group.

As part of the System Operator Certification exam development cycle, the results of the 2015 job task analysis (JTA) is the baseline for the upcoming set of exams. The EWG will continue to analysis new items and develop a cut score for the pending 2018 exams.

Key deliverables for the System Operator Certification Program:

- Complete analysis of exam Item Bank
- Implementation of Linear On the Fly (LOFT) testing for all exams

NERC will continue to work with industry stakeholders and the exam development vendor to create certification exams that will promote reliability of the North American BPS.

The Continuing Education (CE) program will evaluate and revise the current program criteria as reflected in the program manual. The evaluation will consider the growth and maturation of industry training programs as well as ongoing research in the area of adult learning to ensure the CE program continues to foster improvement of training and promotes quality in training programs.

Resource Requirements

Personnel
No additional personnel are proposed for this area in 2017.

Contractor Expenses
The total proposed consulting and contractor budget is approximately $95k lower in 2017 than the 2016 budget.

Further detail in support of the proposed 2017 contractor and consulting budget to support Training, Education, and Operator Certification is set forth in Exhibit C, which includes a comparison to 2016 budgeted amounts. The primary areas of contractor and consulting support include:

- Testing services to develop, administer, proctor, score, and support system operator certification exams across North America.
- Ongoing hosting and maintenance fees for the System Operator Certification and Continuing Education (SOCCED) database.
- Improvements to the SOCCED database.
- Supplemental support to Continuing Education Review Panel industry volunteers to review and audit over 2,500 individual learning activities and provider applications received each year.[36]
- Audit team leader soft skills training delivered by certified NERC staff using vendor-licensed materials to support effective dialogue and communications between audit teams and registered entities.
- Vendor-supported BES technical training for select ERO staff, including compliance, technical and support staff.
- Risk-based compliance training by recognized specialists for NERC and Regional Entity staff to promote continued development of compliance staff.

[36] Review and approval of learning activity applications results in over 400,000 hours of continuing education per year for the industry's certified system operators.

- Web-based training development for ERO staff and industry, including standards applications, risk assessment training, industry human performance fundamentals, and BES events lessons learned.
- An ERO Enterprise learning management system to support scheduling, computer-based training delivery and record maintenance for ERO and select Enterprise staff.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
TRAINING, EDUCATION and OPERATOR CERTIFICATION

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 1,742,146	$ 1,742,146	$ 0	$ 1,822,089	$ 79,944	$ 1,820,199	$ 1,890
Penalty Sanctions	55,994	55,994	$ -	43,738	(12,256)	43,393	344
Total NERC Funding	**$ 1,798,139**	**$ 1,798,139**	**$ 0**	**$ 1,865,827**	**$ 67,687**	**$ 1,863,592**	**$ 2,235**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	1,867,972	1,867,972	-	1,921,900	53,928	1,921,900	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	-	-	-	-	-	-
Interest	183	2,096	1,913	175	(7)	174	1
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 3,666,294**	**$ 3,668,207**	**$ 1,913**	**$ 3,787,902**	**$ 121,608**	**$ 3,785,666**	**$ 2,236**
Expenses							
Personnel Expenses							
Salaries	$ 857,257	$ 849,104	$ (8,153)	$ 852,091	$ (5,166)	$ 845,520	6,570
Payroll Taxes	64,345	65,293	948	62,727	(1,619)	63,717	(990)
Benefits	133,991	114,786	(19,205)	139,239	5,248	116,375	22,864
Retirement Costs	94,860	97,129	2,268	97,624	2,764	98,587	(963)
Total Personnel Expenses	**$ 1,150,454**	**$ 1,126,312**	**$ (24,142)**	**$ 1,151,681**	**$ 1,227**	**$ 1,124,199**	**27,481**
Meeting Expenses							
Meetings	$ 80,000	$ 55,000	$ (25,000)	$ 55,000	$ (25,000)	$ 55,000	-
Travel	21,139	19,900	(1,239)	21,139	-	21,139	-
Conference Calls	36,500	36,500	-	11,133	(25,368)	11,133	-
Total Meeting Expenses	**$ 137,639**	**$ 111,400**	**$ (26,239)**	**$ 87,272**	**$ (50,368)**	**$ 87,272**	**-**
Operating Expenses							
Consultants & Contracts	$ 675,800	$ 731,460	$ 55,660	$ 580,600	$ (95,200)	$ 580,600	-
Office Rent	-	-	-	-	-	-	-
Office Costs	95,773	104,935	9,161	100,323	4,550	95,323	5,000
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	1,919	1,919	-	1,919	-	1,919	-
Total Operating Expenses	**$ 773,992**	**$ 838,814**	**$ 64,821**	**$ 683,342**	**$ (90,650)**	**$ 678,342**	**$ 5,000**
Total Direct Expenses	**$ 2,062,086**	**$ 2,076,525**	**$ 14,440**	**$ 1,922,295**	**$ (139,791)**	**$ 1,889,814**	**$ 32,481**
Indirect Expenses	**$ 1,737,034**	**$ 1,810,570**	**$ 73,536**	**$ 1,717,923**	**$ (19,111)**	**$ 1,697,734**	**$ 20,189**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 3,799,119**	**$ 3,887,096**	**$ 87,976**	**$ 3,640,218**	**$ (158,901)**	**$ 3,587,548**	**$ 52,670**
Change in Assets	**$ (132,825)**	**$ (218,888)**	**$ (86,063)**	**$ 147,684**	**$ 280,510**	**$ 198,118**	**(50,434)**
Fixed Assets							
Depreciation	(1,919)	(3,838)	-	(1,919)	-	(1,919)	-
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 115,031	$ 103,360	(11,671)	119,202	$ 4,171	$ 124,084	(4,882)
Inc(Dec) in Fixed Assets (C)	**$ 113,112**	**$ 99,522**	**$ (11,671)**	**$ 117,283**	**$ 4,171**	**$ 122,165**	**$ -**
TOTAL BUDGET (=B + C)	**$ 3,912,231**	**$ 3,986,618**	**$ 76,305**	**$ 3,757,501**	**$ (154,731)**	**$ 3,709,713**	**$ 47,788**
FTEs	**7.38**	**7.39**	**0.01**	**7.05**	**(0.33)**	**7.07**	**(0.01)**

Administrative Services

Administrative Services (in whole dollars)	Direct Expenses and Fixed Assets			FTEs						
	2016 Budget	2017 Budget	Increase (Decrease)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget - Prior Draft	Draft Over(Under)	2017 FTE -Prior Draft	Prior Draft Over(Under)
General and Administrative	$ 9,881,311	$ 10,205,977	$ 324,666	17.52	16.92	(0.60)	10,048,346	157,631	16.01	0.91
Legal and Regulatory	3,465,966	3,292,379	(173,587)	12.22	11.28	(0.94)	$ 3,370,002	(77,623)	12.25	(0.97)
Information Technology	12,156,674	12,480,846	324,171	22.13	23.27	1.14	$ 12,448,188	32,658	23.31	(0.05)
Human Resources	1,510,177	1,608,583	98,406	2.77	2.82	0.05	$ 1,684,684	(76,102)	3.77	(0.95)
Finance and Accounting	3,428,307	3,827,050	398,743	16.60	15.04	(1.56)	$ 3,844,269	(17,219)	16.01	(0.97)
Total Administrative Services	**$ 30,442,435**	**$ 31,414,834**	**$ 972,399**	**71.23**	**69.33**	**-1.91**	**$ 31,395,489**	**19,345**	**71.36**	(2.03)

Program Scope and Functional Description

NERC's Administrative Services area includes the budget for all business and administrative functions of the organization, including (1) technical committees and member forums; (2) General and Administrative, which includes Board fees and expenses, the president and chief executive officer (CEO), chief reliability officer (CRO) and support staff, communications, external affairs and governmental relations, and office rent; (3) Legal and Regulatory; (4) Information Technology; (5) Human Resources; (6) Finance and Accounting; and (7) other general administrative expenses necessary to support program area activities. These functions are necessary to the existence and functioning of the organization and support the performance of NERC's ERO statutory activities. The costs of the Administrative Services functions are allocated to the five statutory programs as indirect expenses. The resource requirements and comparative budget information for each of these functions are described below.

Technical Committees and Members' Forum Program

While NERC management and staff will continue to interact with and support numerous reliability-related forums (e.g., the North American Transmission Forum and Generator Forum), NERC's 2017 budget does not contain specific funding for any forum activities.

General and Administrative

Background and Scope

The General and Administrative area is responsible for the administration and general management of the organization. Expenses allocated in this area include office rent; personnel and related costs of the CEO, the CRO, the CEO's executive assistant, communications, external affairs and government relations staff, and costs related to the Board. No additional personnel are budgeted for 2017 beyond current staffing. The increase in FTEs in the General and Administrative area is due to a reallocation occurring in 2016 of personnel supporting the Member Representatives Committee and Regional Entity Management Group activities.

The following table details the Board costs included in the total costs of the General and Administrative area.

Board of Trustee Expenses	Budget 2016	Projection 2016	Budget 2017	2017 v 2016 Budget	Variance %
Meetings and Travel Expenses					
Quarterly Board Meetings	$ 244,000	$ 244,000	$ 244,000	$ -	
Trustee Travel	150,000	150,000	150,000	-	
Total Board of Trustees Meetings and Travel Expenses	**$ 394,000**	**$ 394,000**	**$ 394,000**	**$ -**	
Professional Services				-	
Independent Trustee Fees	$ 1,126,354	$ 1,126,354	$ 1,226,000	$ 99,646	
Trustee Search Fees	100,000	100,000	100,000	-	
Total Board of Trustee Professional Services Expenses	**$ 1,226,354**	**$ 1,226,354**	**$ 1,326,000**	**$ 99,646**	**8.13%**
Total Board of Trustee Expenses	**$ 1,620,354**	**$ 1,620,354**	**$ 1,720,000**	**$ 99,646**	**6.15%**

Legal and Regulatory

Background and Scope

The Legal and Regulatory department's workload is derived from the following key NERC program areas: Compliance Analysis and Certification and Registration, Reliability Risk Management, Reliability Assessment and Performance Analysis, and Standards. In addition, the Legal and Regulatory department is also responsible for providing a wide range of legal support to the NERC management team regarding antitrust, corporate, commercial, insurance, contract, employment, real estate, copyright, tax, legislation, and other legal matters. The department also addresses legal and regulatory matters that arise in connection with the delegation agreements with the Regional Entities.

Resource Requirements

Due to process improvements and increased efficiency, the number of FTEs allocated to the department was reduced in 2017 compared to 2016.

Outside law firms and consultants supporting this area are budgeted and tracked as Professional Services. The Professional Services budget for 2017 was reduced by approximately 25% compared to the 2016 budget.

Information Technology

Background and Scope

NERC's IT department plan includes capital and operating expenses required to support, build, configure, and enhance applications that serve registered entities, Regional Entities, and NERC staff. The plan also includes work related to ERO Enterprise data analysis, as well as ongoing NERC internal operations.

The focus of the 2017 – 2019 budget places a heavy emphasis on applications and data analytics designed to improve and enhance the efficiency and productivity of NERC and the Regional Entities, and support more consistent and streamlined interactions with registered entities. These investments will provide broad benefits across the ERO Enterprise in terms of the efficiency and effectiveness of operations and meeting our reliability goals. Additionally, by working to provide more services to the Regional Entities in terms of tools and systems, associated economies of scale will result in these initial investments providing increasing value across the ERO Enterprise in the years to come.

The budget is broken down into four categories as follows:

1. **ERO Enterprise New Functionality –** Items listed in this category are those items designed to add, enhance, or improve, capabilities for registered entities, Regional Entities, and NERC staff. This includes items such as Enterprise Reporting, data analytics and warehousing, the Misoperation

Information Data Analysis System (MIDAS), User Management and Registration (UMR), and the Generating Availability Data System for Wind Turbine Generation (GADS Wind).

2. **ERO Enterprise Infrastructure & Support –** Items listed in this category are those infrastructure and support items required for applications used by registered entities, Regional Entities, and NERC staff. Items include The Events Analysis Management System (TEAMS), the Bulk Electric System Notification and Exception System tool (BESnet), the Standards Balloting System (SBS), the Reliability Coordinator Information System (RCIS), and numerous other applications.
3. **NERC New Functionality –** Items in this category are those items that enhance or improve the internal NERC infrastructure, such as Document Management, telephony, and audio visual.
4. **NERC Infrastructure & Support –** Items listed in this category are primarily those items required to maintain and run the internal office infrastructure, and support NERC staff operations. Items include server hardware and software licenses, network equipment, data and telecommunication circuits, and data storage, as well as office administrative applications (e.g., Microsoft Office) and user hardware such as laptops and peripherals.

A further discussion of each item is outlined below:

ERO Enterprise New Functionality:
As noted above, this category is primarily those applications or systems designed to improve or add capability to registered entities, Regional Entities, and NERC staff. Over the past two years, IT has been successful at deploying a number of new applications and functionality for the ERO Enterprise that have now moved into support. In 2017 and beyond, IT will continue that trend with a heavy focus on data and analytics.

a. Enterprise Reporting. In 2015, IT was successful at providing Enterprise Reporting Phase 1 and 2. In the latter part of 2016, IT will bring generation performance data into the Enterprise Reporting system. In 2017 and subsequent budget planning years IT will focus on additional datasets, as well as increasing the analytical and data mining capabilities for the ERO Enterprise.

b. Entity Registration. In 2016, IT began an effort to replace its existing "User Management Program" customer relationship management tool with one based on Microsoft Dynamics CRM (xRM). In 2017, that effort will be extended by integrating the compliance registration function into the xRM system, including implementation of the "common registration form." This will result in a common registration system shared across the ERO Enterprise that provides a consistent user experience for registered entities.

c. Compliance Monitoring and Enforcement Process Tools. IT will also work closely with the Regional Entities in 2017 to evaluate and implement strategic investments in tools that support the Compliance Monitoring and Enforcement Process. Items under consideration at this time include how NERC and the Regional Entities manage registered entity information (and how that information integrates with Enterprise Reporting to provide reliability risk analysis functionality), how Reliability Standards data is stored and maintained, and how best to support the various parts of the compliance and enforcement process (e.g., analysis of risk, development of implementation plans and audit schedules, actual compliance monitoring, and enforcement processing). Funding for any capital investments in new Enterprise Compliance and Monitoring Tools will be subject to review and approval as part of the business plan and budget application to the year when such investments are proposed to be made.

d. Extranet Development – NERC IT currently provides external collaboration function through the use of secure WebDAV folders and limited deployment of Microsoft SharePoint. In 2017, IT will

develop a more robust implementation of SharePoint to provide better services and support for collaboration across the ERO Enterprise and with stakeholders.

ERO Enterprise Infrastructure & Support:
This line item primarily consists of items used by registered entities, Regional Entities, and NERC Staff. During 2015, and 2016, IT, worked closely with the Regional Entities to design and configure a number of ERO Enterprise applications, with a bias toward using Commercial-off-the-Shelf (COTS) technology whenever possible. Infrastructure and support for these COTS tools (such as SharePoint and the Dynamics xRM platform), as well as custom built applications developed in the past, require ongoing investment to maintain continuous operations. For many applications and systems, this includes the cost of maintaining development, quality assurance, and staging and production environments, which are required to ensure the security and operational integrity and stability of the multiple applications supported for the ERO Enterprise. These applications and systems are monitored, tested (including penetration and vulnerability testing), and maintained in a manner as to ensure the highest level of integrity, security, and availability to the roughly 4,000 users across North America.

In 2016, IT placed emphasis on ensuring the environment was configured in a manner consistent with enterprise best practices, ensuring the security and integrity of the environment while allowing ERO Enterprise users to obtain the information and resources required to perform various analyses. Ongoing support for applications such as TEAMS, MIDAS, SBS, the Reliability Analysis Data System (RADS), in addition to numerous legacy ERO Enterprise products, make up this portion of the IT budget.

NERC New Functionality:
Items included in this category are primarily those items designed to improve, enhance, or replace existing functionality for internal NERC staff and, generally speaking, are not consumed by ERO Enterprise clients.

a. **Document Management Program and Intranet Enhancement** – During 2015 and 2016, NERC began implementation of a document management system, leveraging SharePoint 2013 as the foundational platform. The implementation of a document management program supports a number of important business requirements, including:

   - Ensuring proper classification and management of confidential information
   - Addressing a number of internal audit recommendations/mitigating corporate risk
   - Improving information access and search capabilities
   - Facilitating working group, team, and stakeholder collaboration
   - Supporting document retention policy and procedures
   - Simplifying document retrieval
   - Improving version control of documents
   - Improving workflow control (review and approval of documents)
   - Increasing efficiency and employee productivity

   Two additional products were integrated as part of this effort: Gimmal Compliance Suite, an add-on to SharePoint, which enables robust records management capabilities, and Repstor Affinity, which enables offline visibility into content repositories via Microsoft Outlook. In 2016, NERC will implement document management for six program areas. In 2017, NERC will bring the remaining program areas online. The implementation of a document management system is a multi-year initiative designed to greatly reduce the manual and labor-intensive

effort of managing thousands of documents by streamlining the storage, security, versioning, data classification, and archiving of NERC information.

b. **Audio Visual –** During 2016, IT will replace audit visual (AV) equipment in NERC's primary conference rooms with a Cisco WebEx solution designed to enhance capability (e.g. video conferencing), in addition to reducing cost of travel, when possible. In 2017, as appropriate and approved, additional conference rooms will be refreshed with AV equipment.

c. **IT Infrastructure Services** – During 2016, IT undertook an initiative to leverage qualified vendors for sourceable work, allowing IT to place a greater emphasis on ERO Enterprise projects. Network monitoring is one example of where we have been successful in moving items such as monitoring to a qualified vendor. While technically not "new" capability, implementation of this new approach to network monitoring allows NERC's internal IT resources to focus on larger initiatives designed to serve the ERO Enterprise. IT will continue to pursue this strategy in 2017 as additional work is identified that can be efficiency and cost effectively assumed by qualified vendors.

d. **Public Facing Website Improvements** - Over the past several years, NERC has routinely made updates to its outward-facing Internet presence, during which technology improvements are made and suggestions and requests are implemented. In 2017, IT will work with the company's communications department to begin a project to review the information architecture of the NERC.com site and make changes with the goal of providing a more streamlined user experience.

NERC Infrastructure & Support

As previously noted, NERC Infrastructure & Support are those items required to maintain and support the internal infrastructure for NERC staff. Items such as file servers, network equipment, storage, Microsoft Office (Word, Excel, PowerPoint, Email, SharePoint, etc.), along with security and telecommunications are required to ensure staff have the necessary tools and technology to perform their daily operational functions. Emphasis in 2017 and in the 2018 – 2019 planning cycle will continue to work toward optimizing the amount of effort placed on NERC infrastructure and support to minimize spend on internal office steady state operations, allowing a larger portion of IT resources to focus on new ERO Enterprise functionality, as well as ERO Enterprise infrastructure and support. Examples of items included in internal operations are outlined below**:**

a. **Compliance Reporting and Tracking System (CRATS)** – This compliance database is used to track violations, mitigation plans, and reporting required by NERC as the certified ERO. In addition, the compliance database has additional modules included, such as the Standards, Technical Feasibility Exceptions (TFEs), and Registration module, which contains a list of all registered entities. Funding requirements include ongoing maintenance and enhancements to the CRATS compliance tools.

b. **Meeting Manager, ERO Membership, RCIS, Central Repository of Curtailment Events (CRC)** – NERC maintains a number of legacy applications. Many of the legacy applications were developed and implemented five to ten years ago and are unable to benefit from contemporary application development. Some may have to be completely rewritten, or moved to the xRM application platform, as IT was able to do with Application Broker, NERC MyAccount and UMP in 2016. Funding in 2017 is required for ongoing maintenance and enhancements until the applications can be rewritten or moved to the xRM platform or, in some cases, potentially divested or transferred to industry support.

c. **Quarterly Penetration and Vulnerability Testing All NERC Networks and Systems** – Expert consulting services to provide ongoing intrusion detection and vulnerability testing of the

NERC public website, NERC's network, applications, and systems is an essential requirement of ongoing operations. NERC is subject to frequent intrusion attempts where external parties try to gain access to our systems and infrastructure. Any vulnerability identified is documented and provided to NERC IT for rapid remediation.

d. **NERC Security Program -** NERC's IT department performs a number of technology initiatives to ensure the security of the network and infrastructure. However, in order to continually improve security, a more holistic approach is required that implements technology improvements and constructs an overarching security program to ensure all aspects of security have been considered, including information classification, review of retention policies, and enforcement of security guidelines. During 2016, IT undertook an initiative to improve several processes and will continue to place a high emphasis on security over the coming years.

Robust Planning for New Capital Projects

In connection with the 2016 business planning cycle, the company significantly improved its approach to evaluating potential capital investments in major enterprise software applications. The company has adopted an enterprise information technology investment planning methodology that ensures only projects with compelling and approved business cases are funded. The approval process uses a four approval gates:

- A Business Unit Sponsor approval gate,
- A NERC VP/CTO approval gate,
- An ERO Technology Leadership Team (comprised of the NERC CEO and two Regional Entity CEOs) approval gate, and
- The full ERO-EMG (CEOs of NERC and each Regional Entities) approval gate.

This gated process provides the required rigor and discipline to ensure only high value enterprise IT investments are pursued. In addition, all Enterprise IT investments are subject to ongoing oversight by a subgroup consisting of four members of the Board's Standards Oversight and Technology Committee. The company will continue to use this process for the 2017 – 2019 budget planning cycle.

Examples of the results of this methodology in 2016 include investments in TEAMS and the RADS.

TEAMS. The TEAMS application provides integration of events data systems, while enabling a more efficient and effective method for event data collection, tracking, analysis and reporting. This enhances the ability of the ERO and stakeholders to identify and focus on significant and emerging reliability risks. This tool is used by NERC and the Regional Entities, providing a consistent experience for all ERO clients involved in the events analysis business process. The benefits provided by the TEAMS application streamline ERO Enterprise reliability data sources with an event data collection platform that is consistent with the event analysis process. Benefits include:

- **Improving Efficiency:** TEAMS helps ensure the reliability of the Bulk Power System by facilitating:
  - The reporting of a BPS event
  - The evaluation of BPS events
  - The undertaking of appropriate levels of EA
  - The generation of lessons learned

  - The generation of reliability trend analysis

- **Managing Reliability Risk:** TEAMS enables the ERO Enterprise to integrate event reports with other reliability data sources and develop portfolios of risk information. This integration enables a more complete analysis into the cause of events, including transmission outages, generation trips, and load loss. With this analysis, the ERO Enterprise can better identify unplanned service interruptions and spotlight key areas for reliability improvement, with the ultimate goal of reducing the probability and reliability impact of future system events.
- **Fostering Collaboration:** Increased efficient and effective collaboration amongst NERC and the Regional Entities has resulted through the centralization and appropriately secure distribution of information across Regions (including EA results, trending analysis, and lessons learned), and the increased clarity and standardization of processes provided by the software solution.

RADS. The RADS system provides for a more efficient method for NERC to complete seasonal and long-term reliability assessment reports. Specifically, RADS automates the importing of data, provides for ad hoc and pre-defined reporting, and provides access to historical data. In fact, a recent benchmarking exercise indicated that RADS enabled a routine data import process to be completed in 22 minutes as compared to prior manual work efforts totaling roughly 80 hours. This process improvement has allowed NERC's analysts and engineers to spend more time analyzing reliability and less time importing and managing data. Additional benefits of RADS include:

- **Management of Reliability Risk.** By allowing analysts to refocus their efforts on higher value work, the implementation of RADS is resulting in more and better analyses of future conditions and risks.
- **Improved Quality.** Part of the reason for the respected status of the ERO and its assessments is the high level of quality embodied within its documents. If factual errors were introduced into NERC's reliability assessments, such errors would considerably diminish the ERO's credibility. By centralizing information and reducing the number of manual interventions required to manage data, the RADS system aids in ensuring that the information contained within NERC assessments is accurate and correct.
- **Increased Security.** NERC has obligations to ensure the integrity and security of assessment data. Having a central place to manage and store assessment data has reduced the number of instances of confidential proprietary data being handled and managed at NERC. As such, the risk of accidental inappropriate disclosure has been reduced.

Document Management. As a third example, as described previously, NERC commenced implementation of a document management program during 2015 and 2016. The evaluation of the cost-benefit of the document management program indicated tremendous value to the organization, primarily in terms of addressing the business requirements set forth above. The cost benefit analysis of this project also demonstrated that NERC's projected average cost per user is comparable to market. In addition, assuming achievement of modest personnel efficiency gains (between 2-7 percent) from using the new system, the program will generate value in terms of increased resource availability well above anticipated costs. The project was reviewed in depth with the board of trustee's Standards Oversight and Technology Committee and Finance and Audit Committee, which, together with the Board, authorized reserve funding at their May, 2015 meetings to commence initiation of the program.

In all three of these examples, NERC's planning process and associated approval gates have led to thorough review of both costs and benefits of technology benefits prior to moving forward. As the planning process has matured, NERC has begun to analyze potential benefits to the Regional Entities when considering the benefits from potential IT investments. In the Enterprise Reporting – GADS business case brought before the TLT in April, NERC included estimates of productivity gain in terms of both NERC staff and the staff of the Regional Entities. NERC estimated that across the ERO Enterprise, in the first year of operation, 32 Regional Entity employees would save roughly 10 hours of time and 42 NERC employees would save roughly 29 hours of time, with benefits increasing in future years as users became more familiar with the system and as the system was expanded with additional data. This saved time represents additional value that those employees can provide by not having to manage data or duplicate work. Beyond this analysis, the business case considered less quantifiable benefits to both NERC and the Regional Entities in terms of supporting the ERO Enterprise Strategic Plan and reducing reliability risk.

As the planning process continues to develop and mature, NERC will continue to expand incorporation of regional staffing and budget impacts into its business case analysis, as well as identifying economies of scale, efficiency improvements, and enhancements to reliability through IT investment.

Resource Requirements

Personnel

The increase in Information Technology FTEs is due to the reallocation of personnel to strengthen project management oversight over NERC and ERO Enterprise software application development and implementation.

Contract and Consulting Resources to Support Internal Operations

The 2017 budgeted amounts are set forth in Exhibit C, with a comparison to 2016 budgeted amounts. The increase in the 2017 budget compared to 2016 is primarily due to the inclusion of ongoing maintenance costs for recently added ERO Enterprise applications and costs for the document management program.

2017 IT Operating Expenses

A summary of the major categories of IT Operating Expenses are set forth in the following table:

Office Costs	Budget 2016	Budget 2017	Variance
Telephone	$ 225,000	$ 230,000	$ 5,000
Telephone - Answering Service	3,000	2,500	(500)
Internet	350,000	358,920	8,920
Computer Supplies and Maintenance			
Computers	25,000	25,000	-
Computer Supplies	96,100	98,100	2,000
Maintenance & Service Agreements	1,365,295	1,706,088	340,793
Software	59,000	59,000	-
Subscription and Publications	108,300	108,300	
Dues	2,500	2,500	
Express Shipping	5,000	5,000	-
Total Office Costs	**$ 2,143,420**	**$ 2,595,408**	**$ 356,213**

Telephone Expenses
Office telephone costs are items associated with cellular phone, mobile laptop cellular air card, Session Internet Protocol (SIP) data circuits, and conference calling expenses.

Internet Expense
Internet expense is comprised of data circuits, and redundant capability in the event of primary service provider failure.

Computer Supplies and Maintenance
Computers are items that do not meet the criteria to be considered a capital expense, such as desktop computers or iPads. Computer supplies are expense items required for infrastructure support. Maintenance and service agreements comprise those items required to support internal and external access to routers, switches, firewalls, intrusion protection, file servers, audiovisual equipment, storage area networks, data backup services, network and security monitoring, co-location data center services, video conferencing, digital certificates, and development and virtualization software. Service agreements related to the co-location data center, offsite backup of data, conference calling, and network and security monitoring consume a large portion of the maintenance and service agreements budget.

Software
Tools such as Adobe Creativity Suite, remote support tools, and various other IT support tools are included under this line item. The tools are primarily used for NERC infrastructure purposes to support and manage the application, server, and network environment.

2017 IT Fixed Asset (Capital) Expenses
The following table presents a summary of NERC's IT 2017 fixed asset (capital) budget[37] compared to the 2016 budget:

IT CAPITAL BUDGET	2016	2017
ERO Application Development	$ 1,500,000	$ 700,000
Document Management	465,000	335,000
Hardware (Storage, servers, laptops)	955,000	991,000
Other Equipment	535,000	885,000
Disaster Recovery	200,000	150,000
NERC Software licenses	256,000	211,000
Total IT Capital Budget	**$ 3,911,000**	**$ 3,272,000**

As in prior years, the goal of the 2017–2019 planning period is to provide access, visibility, and analysis of data from many different sources; this will requires ongoing investments in hardware, software, and associated tools. The overarching theme is to securely gather, analyze, and maintain data across the ERO Enterprise to support ERO operations. Adding the capability to centralize and mine data—in addition to foundational elements such as the Microsoft xRM application, SharePoint 2013, and disaster recovery and enhanced security—sets the stage for vastly improved reporting and business intelligence. It also allows the capability for collaboration and sharing of information vital to the ERO's mission.

[37] NERC's total 2017 fixed asset (capital) budget is $4,372,000, and includes $1.1M budgeted in E-ISAC for portal enhancements and other costs related to CRISP.

In addition to the investments described above to support efficiency and consistency across the Enterprise, the 2017 budget also includes the cost of security enhancements, network assets, software, servers, laptops, and other hardware to support daily operations.

Human Resources

Background and Scope

Human Resources (HR) manages all of NERC's HR functions, including staffing, benefits administration, employee relations, performance and compensation management, and training and development. Management has implemented a robust, objective, and auditable performance management system to track corporate and individual performance against pre-established goals, objectives, and measures. Each year NERC continues to refine and improve this system.

Leadership, Management, and Professional and Administrative Staff Training and Development

As part of the 3-year ERO Enterprise Strategic Plan to engage and retain highly qualified talent with the leadership and technical skills to support the mission, NERC's executives, managers, and professional and support staff participate in ongoing training and development to improve competencies critical to success and succession planning for critical roles. As such, NERC will continue to invest in learning opportunities in several areas. First, HR will continue to host and optimize an e-leaning platform, SkillSoft, to provide staff resources for improving soft and technical skills. Second, HR will provide broad-based staff development training though real-world access via tours of and training on control centers, electric substations, and power generation plants. Finally, staff will have access to additional education, including but not limited to degree-oriented university education, pursuit of specialized certifications, and other in-house and external training that provides essential competencies and skills development that will lead to improved organization performance.

Compensation Consulting

Consultants are periodically retained to examine appropriate compensation based on current market data. This ensures that decisions affecting compensation are made in light of the current market climate and that qualified employees are attracted and retained within a defined total remuneration range. NERC also periodically retains compensation subject matter experts to perform periodic assessments of the BOT compensation model to ensure alignment with market practices.

Surveys

NERC periodically retains a vendor to conduct Board of Trustees and committee effectiveness surveys to identify improvement opportunities. HR will also launch additional surveys as appropriate, based on business needs, which may include periodic internal climate surveys.

Succession Planning

Minimizing disruption of knowledge, skill, and experience of key staff is critical to the company's success. HR works with senior management to identify essential roles and develop strategies to build succession and contingency plans for any loss of staff.

HR Products and Services Automation

HR will continue to operate, maintain, and investigate investment in additional electronic platforms for HR support services that reduce administrative burden and improve employee access to tools and information.

Resource Requirements

Personnel
The slight increase in FTEs is due a lower vacancy rate in 2017 compared to 2016.

Contractor Expenses
Contractor and consultant expenses are set forth in additional detail in Exhibit C. The increase over 2016 is primarily due to increased investments for additional leadership and staff training.

Miscellaneous Expenses
Miscellaneous expenses include community responsibility and employee engagement, the year-end employee appreciation event, and employee rewards and recognition.

Finance and Accounting

Background and Scope

NERC's Finance and Accounting department manages all finance and accounting functions, including employee payroll, 401(k), 457(b), and 457(f) plans, travel and expense reporting, monthly financial reporting, sales and use tax, meeting and events planning and services, insurance, internal auditing, and facilities management. This area also holds primary responsibility for the development of the annual business plan and budget, as well as NERC's proposed ERO risk management framework. Over the past several years, NERC's Finance and Accounting department implemented additional policies, procedures, and controls governing day-to-day practices including contract and personnel procurements, meetings, conference planning and travel, expense reimbursement, and back office systems and procedures. The department will continue to refine, improve and, where necessary, implement additional procedures and controls.

Resource Requirements

Personnel
The reduction in FTEs is due to a reallocation of resources to other departments in 2016.

Contractor Expenses
$457k is budgeted for outside contractor and consulting support, representing an increase compared to the 2016 budget. These costs are primarily for outside professional support for auditors to support various risk management and internal control and audit intiatives, as well as to provide finance and accounting support.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
ADMINISTRATIVE SERVICES

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 561,427	$ 626,997	$ 65,570	$ 519,083	$ (42,344)	$ 952,667	$ (433,583)
Penalty Sanctions	-	-	-	-	-	-	-
Total NERC Funding	**$ 561,427**	**$ 626,997**	**$ 65,570**	**$ 519,083**	**$ (42,344)**	**$ 952,667**	**$ (433,583)**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	-	-	-	-	-	-
Interest	-	-	-	-	-	-	-
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 561,427**	**$ 626,997**	**$ 65,570**	**$ 519,083**	**$ (42,344)**	**$ 952,667**	**$ (433,583)**
Expenses							
Personnel Expenses							
Salaries	$ 11,054,511	$ 11,050,223	$ (4,288)	$ 11,858,590	$ 804,078	$ 11,864,014	(5,425)
Payroll Taxes	662,269	656,558	(5,711)	669,299	7,030	687,162	(17,862)
Benefits	1,369,805	1,348,538	(21,267)	1,333,443	(36,362)	1,385,477	(52,034)
Retirement Costs	1,024,669	1,101,571	76,902	1,073,642	48,973	1,088,601	(14,959)
Total Personnel Expenses	**$ 14,111,254**	**$ 14,156,890**	**$ 45,636**	**$ 14,934,974**	**$ 823,720**	**$ 15,025,254**	**(90,280)**
Meeting Expenses							
Meetings	$ 315,000	$ 351,681	$ 36,681	$ 350,000	$ 35,000	$ 315,000	35,000
Travel	653,945	651,240	(2,705)	653,945	-	653,945	-
Conference Calls	63,300	62,110	(1,190)	19,307	(43,994)	19,307	-
Total Meeting Expenses	**$ 1,032,245**	**$ 1,065,031**	**$ 32,786**	**$ 1,023,251**	**$ (8,994)**	**$ 988,251**	**35,000**
Operating Expenses							
Consultants & Contracts	$ 3,036,671	$ 2,585,495	$ (451,176)	$ 3,359,787	$ 323,116	$ 3,199,787	160,000
Office Rent	3,054,287	2,987,777	(66,510)	3,117,009	62,722	3,117,009	-
Office Costs	2,920,678	2,713,155	(207,523)	3,275,952	355,274	3,245,952	30,000
Professional Services	2,334,300	1,961,280	(373,020)	2,293,135	(41,165)	2,293,135	-
Miscellaneous	32,000	32,000	-	32,000	-	32,000	-
Depreciation	1,920,234	1,751,253	(168,981)	1,233,650	(686,584)	1,233,650	-
Total Operating Expenses	**$ 13,298,171**	**$ 12,030,960**	**$ (1,267,210)**	**$ 13,311,534**	**$ 13,363**	**$ 13,121,534**	**$ 190,000**
Total Direct Expenses	**$ 28,441,669**	**$ 27,252,881**	**$ (1,188,788)**	**$ 29,269,759**	**$ 828,090**	**$ 29,135,039**	**$ 134,720**
Indirect Expenses	**$ (28,551,669)**	**$ (27,323,087)**	**$ 1,228,582**	**$ (29,376,484)**	**$ (824,815)**	**$ (29,257,139)**	**$ (119,345)**
Other Non-Operating Expenses	**$ 110,000**	**$ 70,206**	**$ (39,794)**	**$ 106,725**	**$ (3,275)**	**$ 122,100**	**(15,375)**
Total Expenses (B)	**$ -**	**$ 0**	**$ (0)**	**$ -**	**$ 0**	**$ -**	**$ 0**
Change in Assets	**$ 561,427**	**$ 626,997**	**$ 65,570**	**$ 519,083**	**$ (42,344)**	**$ 952,667**	**(433,583)**
Fixed Assets							
Depreciation	(1,920,234)	(1,751,253)	168,981	(1,233,650)	686,584	(1,233,650)	-
Computer & Software CapEx	2,347,000	2,749,562	402,562	1,472,000	(875,000)	1,572,000	(100,000)
Furniture & Fixtures CapEx	-	14,611	14,611	-	-	-	-
Equipment CapEx	1,464,000	365,000	(1,099,000)	1,800,000	336,000	1,800,000	-
Leasehold Improvements	-	566,361	566,361	-	-	-	-
Allocation of Fixed Assets	(1,890,766)	(1,944,281)	(53,515)	(2,038,350)	(147,584)	$ (2,138,350)	100,000
Inc(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ (0)**	**$ -**	**$ (0)**	**$ -**	**$ 100,000**
TOTAL BUDGET (=B + C)	**$ -**	**$ 0**	**$ (0)**	**$ -**	**$ 0**	**$ -**	
FTEs	**71.23**	**73.62**	**2.39**	**69.33**	**(1.91)**	**71.36**	**(2.03)**

Section B — Supplemental Financial Information

Breakdown by Statement of Activity Sections

The following detailed schedules support the consolidated Statement of Activities. All significant variances were described by program area in the preceding pages.

Table B-1
Operating Reserve and Assessment Analysis

Operating Reserve and Assessment Analysis Statutory		Total Reserves	Future Obligations Reserve[1]	Operating Contingency Reserve	Operator Certification	CRISP	Assessment Stabilization Reserve
Beginning Working Capital and Operating Reserves Balance		**6,075,782**	**3,431,795**	**1,213,419**	**930,568**	**500,000**	
Generation or (Use) from 2016 Operations							
From 2016 budgeted operations		862,799		1,109,651	(246,852)		
From 2016 approved use of reserves		(1,117,056)	(320,218)	(796,838)			
Proceeds from financing activities (non-current portion only)		1,256,042		1,256,042			
Debt Service		(1,055,000)		(1,055,000)			
Other adjustments to reserves		1,806,132	(464,868)	-			2,271,000
Projected Working Capital and Operating Reserves - 12/31/16		**7,828,700**	**2,646,709**	**1,727,275**	**683,716**	**500,000**	**2,271,000**
Required Working Capital and Operating Reserves - 12/31/17	[2]	**7,759,102**	2,646,709	2,227,275	714,118	500,000	1,671,000
Adjustment in funding to achieve required reserve balance		530,402	-	500,000	30,402	-	
Penalty sanctions available 1-1-2017 (See Table B-2)		500,000					500,000
Less: Penalty sanction offset in 2017		(1,100,000)		-			(1,100,000)
Total Adjustments to Reserves		**(69,598)**	**-**	**500,000**	**30,402**	**-**	**(600,000)**
Assessment Reconciliation							
2017 Expenses and Capital Expenditures		69,602,175		60,018,178	1,291,557	8,292,440	
Less: Penalty sanction offset in 2017		(1,100,000)		(1,073,757)		(26,243)	
Adjustment in funding to achieve required reserve balance		530,402	-	500,000	30,402	-	
Less: Other Funding Sources		(9,195,417)	-	(882,942)	(1,321,958)	(6,990,517)	
Less: Proceeds from financing activities (non-current only)		(966,667)		(966,667)			
Plus: debt service		985,750		985,750			
2017 NERC Assessment		**59,856,243**					

[1] As further explained in the discussion of the Working Capital Reserve amount in Exhibit E, the Future Obligations Reserve offsets future, non-current liabilities. The calculation of Working Capital and Operating Reserve balances per 2015 audited financials and as projected for 2016 and 2017 is included with the Statements of Financial Position on page 91.

[2] On August 11, 2016, the NERC Board of Trustees approved the Working Capital and Operating Reserve Balance at 12/31/17.

Table B-2
Penalties

Penalty Sanctions

Until recently, penalty monies received prior to June 30 were to be used to offset assessments in the subsequent year's budget, as documented in *NERC Policy – Accounting, Financial Statement and Budgetary Treatment of Penalties Imposed and Received for Violations of Reliability Standard*, as well as Section 1107.2 of the Rules of Procedure. The NERC Board has approved an updated Working Capital and Operating Reserves Policy that has also been approved by FERC. This updated Policy allows NERC, with FERC approval pursuant to Section 1107.4 of the Rules of Procedure, to place penalty funds into a new Assessment Stabilization Reserve for use in future years to offset assessments. For the 2017 budget, $500,000 of penalty funds received prior to June 30, 2016 were deposited into this reserve account. NERC proposes that $1,100,000 of those funds be used to offset assessments for the 2017 budget with the remaining $1,671,000 held in the Assessment Stabilization Reserve for future assessment offsets.

All penalties received through June 30, 2016 are detailed below, including the amount and date received.

Allocation Method

Penalty sanctions used to offset 2017 assessments have been allocated to the following statutory programs to reduce assessments: Reliability Standards, Compliance Assurance, Compliance Analysis and Certification, Compliance Enforcement, Reliability Assessments and System Analysis, Performance Analysis, Training and Education, Situation Awareness, Event Analysis, and E-ISAC. Penalty sanctions are allocated based on the number of FTEs in the program divided by the aggregate total FTEs in the programs receiving the allocation. In addition to the information noted below, an additional $500,000 is expected in May 2017 related to an agreed-upon penalty settlement through WECC resulting from the September 2011 blackout.

Penalty Sanctions	Date Received	Amount Received
Penalties received between 7/1/2015 and 6/30/2016		
	May-16	$ 500,000
		$ 500,000
Penalties received prior to 6/30/2015, held in the assessment stabilization reserve		$ 2,271,000
Total penalties available to offset assessments		$ 2,771,000
Adjustments		
Penalties held in assessment stabilization reserve		(1,671,000)
Total Penalty Sanctions included in the 2017 Budget		$ 1,100,000

Table B-3
Outside Funding

Outside Funding Breakdown By Program (Excludes Penalty Sanction)	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget
Reliability Standards				
Workshops	$ 105,000	$ 105,000	$ 105,000	$ -
Interest Income Allocation	445	5,374	427	(18)
Total	$ 105,445	$ 110,374	$ 105,427	$ (18)
Compliance Analysis, Registration and Certification				
Interest Income Allocation	$ 251	$ 2,860	$ 187	$ (64)
Total	$ 251	$ 2,860	$ 187	$ (64)
Compliance Assurance				
Workshops	$ -	$ -	$ -	$ -
Interest Income Allocation	479	$ 4,710	386	(93)
Total	$ 479	$ 4,710	$ 386	$ (93)
Compliance Enforcement				
Interest Income Allocation	$ 302	$ 3,682	$ 327	$ 25
Total	$ 302	$ 3,682	$ 327	$ 25
Reliability Assessments and System Analysis				
pc_GAR Software	$ 50,000	$ -	$ 50,000	$ -
Workshops	15,000	15,000	15,000	-
Interest Income Allocation	462	3,634	351	(111)
Total	$ 65,462	$ 18,634	$ 65,351	$ (111)
Performance Analysis				
Interest Income Allocation	$ -	$ 2,554	$ 234	$ 234
Total	$ -	$ 2,554	$ 234	$ 234
Training and Education				
Testing Fees and Certificate Renewals	$ 1,267,972	$ 1,267,972	$ 1,321,900	$ 53,928
CEH Fees	600,000	600,000	600,000	-
Interest Income Allocation	183	2,096	175	(7)
Total	$ 1,868,155	$ 1,870,068	$ 1,922,075	$ 53,921
Event Analysis				
Workshops	$ 40,000	$ 78,073	$ 40,000	$ -
Interest Income Allocation	274	2,918	281	7
Total	$ 40,274	$ 80,991	$ 40,281	$ 7
Situation Awareness				
Workshops	$ -	$ 1,128	$ -	$ -
Interest Income Allocation	137	1,816	140	3
Total	$ 137	$ 2,944	$ 140	$ 3
E-ISAC				
Third Party Funding (CRISP)	$ 6,830,738	$ 7,335,757	$ 6,990,447	$ 159,709
Workshops	70,000	70,000	70,000	-
Interest Income Allocation	468	6,254	491	24
Total	$ 6,901,206	$ 7,412,011	$ 7,060,938	$ 159,732

- Operator Certification – The 2017 budget reflects prior year actual results and the anticipated number of tests to be taken in 2017.
- E-ISAC – The increase in third-party funding is due to the increase in NERC costs, which are funded equally by participants in CRISP and through assessments.

Table B-4
Personnel

Personnel Expenses	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Total Salaries	$ 28,842,336	$ 29,052,918	$ 30,073,438	$ 1,231,102	4.3%
Total Payroll Taxes	1,871,367	1,830,724	1,847,130	(24,237)	-1.3%
Total Benefits	3,579,280	3,390,190	3,643,806	64,526	1.8%
Total Retirement	2,990,823	3,015,135	3,076,956	86,134	2.9%
Total Personnel Costs	$ 37,283,807	$ 37,288,967	$ 38,641,331	$ 1,357,525	3.6%
FTEs	192.47	145.02	189.88	(2.59)	-1.3%
Cost per FTE					
Salaries	$ 149,852	$ 200,337	$ 158,381	8,529	5.7%
Payroll Taxes	9,723	12,624	9,728	5	0.1%
Benefits	18,596	23,377	19,190	594	3.2%
Retirement	15,539	20,791	16,205	666	4.3%
Total Cost per FTE	**$ 193,710**	**$ 257,130**	**$ 203,504**	**$ 9,794**	**5.1%**

- Salaries - Total Salaries expense is comprised of base salaries, incentive compensation, deferred compensation, employment agency fees and temporary office expenses. The 2017 budget for base salaries assumes a 3% increase over actual 2016 base salaries and is inclusive of market adjustments and promotions. Due to the addition of more senior staff in 2016, and the need to pay higher market-based compensation than previously budgeted to attract and retain employees, the actual average salary is higher than the 2016 budget, which causes the comparison of 2017 budget to 2016 budget to be higher than 3%. The 2017 budget for incentive compensation is based on historical actuals and is slightly higher as a percent of base salaries, 20.9% in 2017 compared to 19.5% in 2016. The 2017 budgets for deferred compensation, employment agency fees and temporary office expenses are generally consistent with 2016.
- Payroll taxes are decreasing based upon the 2016 projection and the reduction in total FTEs. While total Salaries expense is increasing, the maximum salary subject to FICA taxes limits the change in employer costs.
- Benefits are budgeted to increase based on the most recent market data as provided by NERC's insurance broker.
- There have been no changes to NERC's retirement plans. Retirement expenses are increasing at a higher rate consistent with the 3% increase in base salaries.

Table B-5
Meetings

Meetings	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Meetings	$ 1,096,500	$ 1,194,500	$ 1,071,500	$ (25,000)	-2.28%
Travel	$ 2,203,786	$ 2,190,184	$ 2,203,786	(0)	0.62%
Conference Calls	$ 320,000	$ 261,880	$ 97,600	(222,400)	-62.73%
Total Meetings	**$ 3,620,286**	**$ 3,646,564**	**$ 3,372,886**	**$ (247,400)**	**-6.83%**

- The 2017 budget for Meetings expense in the Operator Certification Program is $25.0k lower than the 2016 budget based upon prior year actual results.
- The 2017 budget for Conference Calls is $222.4k, 69.5%, lower than 2016 based upon the planned execution of a contract with a new provider scheduled to occur in 2016. This reduction in Conference Calls expenses will offset an increase in maintenance costs associated with a new audio visual lease related to new equipment and associated service and maintenance agreements.

Table B-6
Consultants and Contracts

NOTE: This table has been replaced by Exhibit C, and is further discussed in the Executive Summary on page 14

Table B-7
Rent

Office Rent	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Office Rent	$ 2,987,777	$ 2,954,287	$ 2,838,144	$ (149,633)	-5.01%
Utilities	-		-	-	
Maintenance	100,000	270,000	278,866	178,866	3.28%
Total Office Rent	**$ 3,087,777**	**$ 3,224,287**	**$ 3,117,009**	**$ 29,232**	**0.95%**

- The decrease in Office Rent is due to the termination of the lease at NERC's former Washington, DC office.
- Maintenance costs at NERC offices increase year over year per the terms of the lease agreements.

Table B-8
Office Costs

Office Costs	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Telephone	$ 548,596	$ 410,053	$ 539,737	$ (8,859)	-1.61%
Telephone Answering Srv	3,000	3,355	2,500	(500)	-16.67%
Internet	375,900	369,021	383,366	7,466	1.99%
Office Supplies	173,800	177,392	194,000	20,200	11.62%
Computer Supplies and Maintenance	-	-	-	-	
Computers	25,000	26,000	25,000	-	0.00%
Computer Supplies	98,400	85,607	101,400	3,000	3.05%
Maintenance & Service Agreements	1,875,126	1,858,992	2,426,139	551,013	29.39%
Software	117,500	226,643	122,500	5,000	4.26%
Network Supplies	-	-	-	-	
Publications & Subscriptions	167,650	190,852	180,460	12,810	7.64%
Dues	48,050	63,165	49,316	1,266	2.64%
Postage	16,350	15,786	16,221	(129)	-0.79%
Express Shipping	28,200	17,405	28,216	16	0.06%
Copying	105,000	104,993	110,123	5,123	4.88%
Reports	2,000	1,362	362	(1,638)	-81.90%
Stationary/Forms	2,500	1,090	2,500	-	0.00%
Equipment Repair/Service Contracts	75,000	75,000	75,000	-	0.00%
Bank Charges	42,500	26,494	25,000	(17,500)	-41.18%
Sales & Use Taxes	5,000	500	-	(5,000)	-100.00%
Merchant Card Fees	86,000	86,575	77,500	(8,500)	-9.88%
Total Office Costs	**$ 3,583,328**	**$ 3,740,288**	**$ 4,359,340**	**$ 563,768**	**21.66%**

- The increase in Office Supplies is primarily related to increased needs at NERC's Washington, D.C. office.
- The increase in Maintenance and Service agreement costs related to:
  - New in software audit tool in Compliance Assurance, $100k
  - New software analytic tools used in RASA, $37k
  - Increase in maintenance costs for new data center hardware installed in 2015 and 2016, and new network storage devices, $200k
  - Increase in maintenance costs for new audio visual equipment planned for 2016, $164k

Table B-9
Professional Services

Professional Services	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Independent Trustee Fees	$ 1,126,354	$ 1,126,354	$ 1,226,000	$ 99,646	8.85%
Trustee Search Fee	100,000	100,000	100,000	-	0.00%
Outside Legal	690,000	590,000	515,000	(175,000)	-25.36%
Lobbying	50,000	50,000	60,000	10,000	20.00%
Accounting & Auditing Fees	154,500	154,500	159,135	4,635	3.00%
Insurance Commercial	225,000	225,000	230,000	5,000	2.22%
Outside Services	163,446	168,446	178,000	14,554	8.90%
Total Services	**$ 2,509,300**	**$ 2,414,300**	**$ 2,468,135**	**$ (41,165)**	**-1.64%**

- The increase in Independent Trustee Fees was approved by the Board of Trustees on August 13, 2015. Independent Trustee Fees are included in the Professional Services budget in the General and Administrative and Executive department.
- The reduction in outside legal fees, budgeted in the Legal and Regulatory department, is based on bringing more work in-house and a reduction in projected outside legal needs due to the completion of certain contract negotiations.
- The increase in Lobbying expense, budgeted in the Legal and Regulatory department, is based upon prior year actual expenses. This expense is primarily related to NERC's monitoring of regulatory and legislative issues and responding to information requests related to these activities.
- The increase in outside service costs is primarily due to various employee benefit management systems budgeted in the Human Resources department.

Table B-10
Miscellaneous

Miscellaneous Expenses	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Miscellaneous Expense	$ 6,500	$ 6,500	$ 6,500	$ -	0.0%
Employee Rewards and Recognition	10,000	$ 10,000	10,000	-	0.0%
Community Resp & Employee Engagement	10,000	10,000	5,000	(5,000)	-50.0%
Year-end Employee Recognition Event	10,000	10,000	15,500	5,500	55.0%
Total Miscellaneous Expenses	**$ 36,500**	**$ 36,500**	**$ 37,000**	**$ 500**	**1.4%**

The total 2017 Miscellaneous Expenses budget shows a minor increase of $500 over the 2016 budget.

This budget is intended to cover the cost of:

1. Token gifts to retiring employees, condolence flowers in the event of a death in the family of an employee, and similar types of miscellaneous expenses ($6.5k);
2. Funds to support Community Responsibility and Employee Engagement Committee activities ($5.0k);
3. Departmental and company team-building activities and employee rewards and recognition expenses that are not otherwise included in personnel expenses ($10.0k); and
4. Year-end employee recognition meal expenses ($15.50k). $5.0k was reallocated from Community Responsibility and Employee Engagement expenses to the Year-End Employee Recognition Event to better align the budget with prior year actual results.

The budget for item (1) is spread throughout all Programs and Administrative departments. The budget for items (2) and (4) are included in the Human Resources department. The budget for item (3) was split equally between General and Administrative and Human Resources in the 2016 Budget, but is budgeted in Human Resources only in 2017.

Table B-11
Other Non-Operating Expenses

Other Non-Operating Expenses	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Property Tax Expense	$ 50,000	50,000	$ 50,000	-	
Interest Expense	60,000	60,000	56,725	(3,275)	-5.46%
Total Other Non-Operating Expenses	**$ 110,000**	**$ 110,000**	**$ 106,725**	**$ (3,275)**	**-2.98%**

Budgeted interest expense is calculated based on expected draws on the capital financing loan. Refer to Exhibit D, page 125 for more detailed information related to debt repayment and the interest expense calculation.

Table B-12
Fixed Assets

Fixed Assets	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Depreciation	$ (2,641,943)	$ (2,558,606)	$ (1,691,457)	$ 950,486	-35.98%
Computer & Software CapEx	2,447,000	2,362,402	2,572,000	125,000	5.11%
Furniture & Fixtures CapEx	-	-	-	-	
Equipment CapEx	1,464,000	1,545,797	1,800,000	336,000	22.95%
Leasehold Improvements	-	-	-	-	
	$ 1,269,057	**$ 1,349,593**	**$ 2,680,543**	**$ 1,411,486**	**111.22%**

As further explained in the Executive Summary on page 15 and in Section A in the Information Technology section on page 77 and the E-ISAC section on page 61, expenditures for fixed assets, excluding the reversal of Depreciation expense, are budgeted to be $461.0k higher in 2017 compared to 2017. The increase in Computer & Software CapEx is primarily due to the combination of lower costs resulting from a delay in the potential replacement for the current compliance monitoring and enforcement tracking tool, originally planned for 2017, and the increase in costs related to the portal enhancement project. This delay in the compliance monitoring and enforcement tracking tool resulted in a $800k decrease in ERO applications development from $1.5M in 2016 to $700k in 2017. The increase in Equipment CapEx is primarily for security devices.

Table B-13
2018-2019 Projections
NOTE: Refer to the Executive Summary beginning on page 21

Section C — Non-Statutory Activity

NERC has no non-statutory activities.

Section D — Supplemental Financial Statements

NORTH AMERICAN ELECTRIC RELIABILITY COPORATION

STATEMENT OF FINANCIAL POSITION

	12/31/2015 Per Audit	12/31/2016 - Projection	12/31/2017 - Projection
ASSETS			
Cash	40,308,955	39,464,020	39,091,525
Trade Accounts receivable, net of allowance for uncollectible accounts of $0 and $62,573 in 2013 and 2012	3,986,346	3,986,346	3,986,346
Prepaid expenses and other current assets	1,291,805	1,291,805	1,291,805
Security deposit	125,416	125,416	125,416
Plan Assets - 457b	744,439	744,439	744,439
Plan Assets - 457f	271,200	271,200	271,200
Property and equipment	8,301,730	9,411,545	12,669,171
Total Assets	**55,029,891**	**55,294,771**	**58,179,902**
LIABILITIES AND NET ASSETS			
Liabilities			
Current Portion			
Accounts payable and accrued expenses (incl, vacation accrual)	5,326,723	5,326,723	5,326,723
Accrued Incentive Comp	4,721,278	4,956,779	4,872,492
Deferred rent-current	322,016	400,434	480,457
Deferred compensation-current	-	-	-
Capital lease obligations - current	64,728	64,728	64,728
Accrued retirement liabilities	1,878,830	1,695,570	1,761,502
Debt Service - Current Portion	744,253	857,725	650,231
Deferred income	7,961,316	7,961,316	7,961,316
Deferred revenue - penalties	-	-	-
Deferred revenue - CRISP	2,508,514	2,508,514	2,508,514
Regional assessments	12,273,666	12,273,666	12,273,666
Total Current Portion	**35,801,324**	**36,045,455**	**35,899,629**
Long-Term Portion			
Deferred compensation[1]	1,038,350	1,038,350	1,038,350
Capital Project Financing - non-current	680,311	1,011,839	1,033,333
Deferred rent - non-current	3,412,298	3,011,864	2,531,407
CRISP Insurance Reserve	500,000	500,000	500,000
Deferred Revenue - Assessment Stabilization Reserve	-	2,271,000	2,271,000
Capital lease obligations - non-current	151,752	151,752	151,752
Total Non-Current Portion	**5,782,711**	**7,984,805**	**7,525,842**
Total Liabilities	**41,584,035**	**44,030,260**	**43,425,472**
Net Assets - unrestricted	9,735,856	10,764,511	14,254,430
Net Assets - restricted	3,710,000	500,000	500,000
Total Liabilities and Net Assets	**55,029,891**	**55,294,771**	**58,179,902**

[1]Includes 457b liability, life insurance for former executive, and retiree medical

NORTH AMERICAN ELECTRIC RELIABILITY COPRORATION

Statement of Activities, Fixed Asset Expenditures and Change in Working Capital by Program	Statutory Total	Statutory Activities: Reliability Standards	Compliance Analysis, Registration & Certification	Compliance Assurance	Compliance Enforcement	Reliability Assessment and System Analysis	Performance Analysis	Operator Certification	Training and Continuing Education	Event Analysis	Situation Awareness	E-ISAC	General and Administrative (Includes Executive and Gov't Relations)	Legal and Regulatory	Information Technology	Human Resources	Accounting and Finance
Funding																	
ERO Funding																	
NERC Assessments	59,856,314	7,835,213	3,576,122	7,713,879	5,677,854	7,339,030	4,821,146		1,822,089	5,300,955	3,980,236	11,270,705	519,083	-	-	-	-
Penalty Sanctions	1,100,000	159,642	69,980	144,334	122,465	131,213	87,475		43,738	104,970	52,485	183,698			-		
Total NERC Funding	**60,956,314**	**7,994,855**	**3,646,102**	**7,858,213**	**5,800,319**	**7,470,243**	**4,908,621**		**1,865,827**	**5,405,926**	**4,032,721**	**11,454,403**	**519,083**	-	-	-	-
Third-Party Funding (CRISP)	6,990,447											6,990,447					
Testing Fees	1,921,900							1,321,900	600,000								
Services & Software	50,000					50,000											
Workshops	230,000	105,000				15,000				40,000		70,000					
Interest	3,000	427	187	386	327	351	234	58	117	281	140	491					
Miscellaneous	-																
Total Funding (A)	**70,151,660**	**8,100,282**	**3,646,289**	**7,858,599**	**5,800,647**	**7,535,594**	**4,908,855**	**1,321,958**	**2,465,944**	**5,446,206**	**4,032,862**	**18,515,341**	**519,083**	-	-	-	-
Expenses																	
Personnel Expenses																	
Salaries	30,073,438	2,340,405	1,125,154	2,509,618	1,790,859	2,247,826	1,349,579	245,337	606,753	1,708,049	873,869	3,417,398	3,476,241	2,148,056	3,261,320	770,439	2,202,533
Payroll Taxes	1,847,130	151,658	76,383	163,335	117,205	142,919	92,093	18,342	44,385	108,739	58,749	204,023	173,245	119,055	216,747	28,144	132,107
Benefits	3,643,806	307,085	174,014	333,557	184,106	263,230	143,104	84,920	54,319	212,232	156,328	397,467	396,300	151,930	389,091	72,977	323,144
Retirement Costs	3,076,956	259,407	126,651	276,273	198,694	246,609	149,018	30,026	67,599	189,397	96,159	363,482	197,650	232,244	359,376	46,242	238,131
Total Personnel Expenses	38,641,331	3,058,556	1,502,203	3,282,783	2,290,865	2,900,585	1,733,794	378,625	773,056	2,218,416	1,185,105	4,382,370	4,243,437	2,651,285	4,226,534	917,802	2,895,916
Meeting Expenses																	
Meetings	1,071,500	207,000	4,000	60,000	2,500	74,000	1,000	30,000	25,000	81,500	6,500	230,000	334,000	4,000	7,500	2,000	2,500
Travel	2,203,786	271,988	155,146	276,343	56,736	208,338	118,172	7,389	13,751	152,487	33,005	256,488	444,515	93,231	56,508	8,728	50,963
Conference Calls	97,600	40,565	610	6,100	366	5,270	2,965	153	10,980	4,270	305	6,710	5,856	1,952	9,608	305	1,586
Total Meeting Expenses	3,372,886	519,553	159,756	342,443	59,602	287,608	122,137	37,541	49,731	238,257	39,810	493,198	784,371	99,183	73,616	11,033	55,049
Operating Expenses																	
Consultants & Contracts	13,127,749			50,000		525,000	528,082	219,800	360,800		1,295,850	6,788,429	15,000		2,312,787	575,000	457,000
Office Rent	3,117,009												3,117,009				
Office Costs	4,359,340	51,336	24,231	141,198	20,379	147,652	74,843	43,216	57,107	49,634	41,897	431,895	507,934	46,411	2,595,408	11,748	114,450
Professional Services	2,468,135											175,000	1,431,000	495,000		63,000	304,135
Miscellaneous	37,000	500	500	500	500	500	500		500	500	500	500	500	500	500	30,000	500
Depreciation	1,691,457	231,721				125,621			1,919	85,582	7,667	5,297	438,305		795,345		
Total Operating Expenses	24,800,690	283,556	24,731	191,698	20,879	798,773	603,426	263,016	420,326	135,715	1,345,914	7,401,121	5,509,749	541,911	5,704,041	679,748	876,085
Total Direct Expenses	**66,814,907**	**3,861,666**	**1,686,689**	**3,816,924**	**2,371,347**	**3,986,965**	**2,459,356**	**679,182**	**1,243,113**	**2,592,388**	**2,570,828**	**12,276,689**	**10,537,557**	**3,292,379**	**10,004,191**	**1,608,583**	**3,827,050**
Indirect Expenses	0	4,180,279	1,832,451	3,779,431	3,206,790	3,435,846	2,290,564	572,641	1,145,282	2,748,677	1,374,338	4,810,185	(10,644,282)	(3,292,379)	(10,004,191)	(1,608,583)	(3,827,050)
Other Non-Operating Expenses	**106,725**	-	-	-	-	-	-	-	-	-	-	-	106,725				
Total Expenses (B)	**66,921,632**	**8,041,945**	**3,519,141**	**7,596,355**	**5,578,137**	**7,422,812**	**4,749,920**	**1,251,823**	**2,388,395**	**5,341,065**	**3,945,167**	**17,086,873**	-	-	-	-	-
Change in Assets	**3,230,028**	**58,337**	**127,149**	**262,244**	**222,510**	**112,782**	**158,936**	**70,136**	**77,549**	**105,141**	**87,695**	**1,428,467**	**519,083**	-	-	-	-
Fixed Assets																	
Depreciation	(1,691,457)	(231,721)	-	-	-	(125,621)	-	-	(1,919)	(85,582)	(7,667)	(5,297)	(438,305)	-	(795,345)	-	-
Computer & Software CapEx	2,572,000											1,100,000			1,472,000		
Furniture & Fixtures CapEx	-																
Equipment CapEx	1,800,000														1,800,000		
Leasehold Improvements	-																
Allocation of Fixed Assets	0	290,058	127,149	262,244	222,510	238,403	158,936	39,734	79,468	190,723	95,361	333,765	438,305	-	(2,476,655)	-	-
Inc(Dec) in Fixed Assets (C)	**2,680,543**	**58,337**	**127,149**	**262,244**	**222,510**	**112,782**	**158,936**	**39,734**	**77,549**	**105,141**	**87,695**	**1,428,467**	-	-	-	-	-
TOTAL BUDGET (=B + C)	**69,602,175**	**8,100,282**	**3,646,289**	**7,858,599**	**5,800,647**	**7,535,594**	**4,908,855**	**1,291,557**	**2,465,944**	**5,446,206**	**4,032,862**	**18,515,341**	-	-	-	-	-
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**549,485**	**(0)**	-	-	-	**(0)**	**0**	**30,402**	-	-	**(0)**	**0**	**519,083**	-	-	-	-
FTEs	**189.88**	**17.16**	**7.52**	**15.51**	**13.16**	**14.10**	**9.40**	**2.35**	**4.70**	**11.28**	**5.64**	**19.74**	**16.92**	**11.28**	**23.27**	**2.82**	**15.04**

Exhibit A – Common Assumptions

Shared Business Plan and Budget Assumptions NERC and the Regional Entities 2016–2019 Planning Period (2017 Budget Cycle)

NERC and the eight Regional Entities are committed to a common operating model[38] that describes the characteristics of a highly effective and efficient electric reliability organization (ERO) Enterprise. This operating model includes action items to address coordinated strategic and business planning as well as performance monitoring processes across the enterprise. These processes remain transparent, with results reported out on a quarterly basis to NERC's Corporate Governance and Human Resources Committee and NERC Board of Trustees (Board) in support of the ERO corporate oversight function.

Recently, at its November 2015 meeting, the Board approved an updated version of the ERO Enterprise Strategic Plan with goals, objectives, and deliverables for the 2016–2019 planning period. The strategic plan lays out five goals that the ERO Enterprise will focus on over the next three years. They include (1) standards; (2) compliance, enforcement, registration, and certification; (3) risks to reliability; (4) emerging risks; and (5) coordination and collaboration. The plan also identifies a number of associated objectives and deliverables to achieve the goals of the ERO Enterprise. There are also four overarching performance metrics to assess the overall effectiveness of the ERO Enterprise in addressing risk to the Bulk Electric System (BES) and improving BES reliability in 2016. These metrics concentrate on (1) measuring progress in achieving reliability results, (2) assuring standards and compliance effectiveness, (3) improving risk mitigation, and (4) program execution.

The following set of common assumptions has been developed to guide ERO Enterprise resource projections[39] for the 2016–2019 period. Specifically, it supports the strategies heading into the 2016 year and establishes common assumptions, goals and objectives as the ERO Enterprise begins the 2017 Business Plan and Budget (BP&B) cycle. Additionally, it outlines how these goals and objectives set the stage for periods beyond 2017, all in support of achievement of the goals and objectives set forth in the Strategic Plan.

Similar to prior planning cycles, the specific resource needs and budgets of NERC and the Regional Entities will be publicly posted and made available on NERC's website for review. Each Regional Entity board approves its BP&Bs after an extensive review process that includes consideration of stakeholder input. Also, the BP&Bs of NERC and each Regional Entity are approved in open session by NERC's Finance and Audit Committee and Board of Trustees as part of the annual BP&B process. NERC's review of the Regional Entity BP&Bs will be primarily focused on ensuring alignment of activities with the Strategic Plan and adequacy of resources to support performance of delegated functions and key efforts. A 2017 BP&B schedule has been developed to identify important meeting dates, review periods, posting dates, etc. associated with the development and completion of the NERC and Regional Entity BP&Bs.

These assumptions will continue to be refined based on comments received from stakeholders and the ongoing work conducted by NERC and Regional Entity leadership regarding specific goals, objectives, and supporting activities over the planning period.

[38] ERO Enterprise Operating Model

[39] NERC recognizes there are often unique factors that drive differences in each entity or organization's final determination of its resource needs and budget. Regional Entity-specific assumptions are stated in each Regional Entity's BP&B as appropriate.

Legal and Operating Framework

NERC and the Regional Entities will continue to work under the existing regulatory framework governing the establishment and enforcement of reliability standards for the BES established by applicable governmental authorities in the United States, provincial regulatory and/or governmental authorities in Canada, and portions of Mexico, as well as the authorizations contained in the Federal Energy Regulatory Commission's (FERC) Order approving NERC as the ERO.

NERC continues to enhance its oversight of the Regional Entities' performance of their delegated functions. NERC in collaboration with the Regional Entities will continue to develop goals, measures, and reports to assess and evaluate the Regional Entities' performance of their Regional Delegation Agreements (RDAs), NERC's Rules of Procedure, the Compliance Monitoring and Enforcement Program, FERC requirements, and directives that are in effect pursuant to Section 8(c) of the RDAs. NERC will continue to provide feedback and direction to the Regional Entities on performance improvements. NERC and the Regional Entities will also continue to work collaboratively to refine and revise processes and procedures to eliminate duplication, increase operational efficiencies, enhance ERO-wide consistency, and achieve measureable reliability outcomes. Regional Entities will continue to have the primary responsibility for day-to-day operations and interactions with registered entities.

Stakeholder Participation

NERC and the Regional Entities develop their BP&B's based upon the assumption of continued stakeholder participation in support of key program areas, while recognizing that stakeholder resource limitations may affect specific levels of participation in any given activity. The availability and adequacy of industry resource support will be evaluated on an ongoing basis.

External Factors

The performance and execution of BP&B's for each entity in the ERO Enterprise may be impacted by various external factors. These factors include, but are not limited to, the following:

- FERC Orders, other applicable governmental authority actions, directives, audits, mitigation efforts, and performance assessments;
- Environmental Protection Agency (EPA) rules that could potentially impact the reliability and/or operation of the BES;
- Other governmental agencies or departments that may issue rules, guidelines, orders, or directives that may impact the operation of the BES;
- The number and significance of changes within Balancing Authorities' and Reliability Coordinators' areas, prompting the need for associated re-certification and reliability plan assessments;
- The unanticipated rise in the rate and severity of entity violations;
- The unanticipated rise in the rate and severity of system events requiring formal investigations beyond historic volumes, and causal drivers of these events;
- New technologies and changes in resource or demand composition that require additional reliability studies and reliability risk analysis, including new techniques for conducting relevant assessments;
- Changes in applicable laws and regulations, including environmental laws and others;
- Priority risk activities identified by the Reliability Issues Steering Committee, committees of the Board, and through other stakeholder input;

- The ability of stakeholders to support the pace and scope of the various activities while implementing the results of earlier efforts.

Collaboration with the Trade Associations and Forums

The activities of the North American Transmission Forum (NATF), North American Generator Forum (NAGF), and other trade forums and associations are expected to complement ERO Enterprise activities and mitigate incremental resource needs of NERC and Regional Entities in certain areas. NERC has a memorandum of understanding with the NATF and NAGF to help ensure that the common objectives of each organization are achieved in the most efficient and effective manner. Increased collaboration between the NERC and the NATF and NAGF is expected to continue.

Key Assumptions by Program Area[40]

Reliability Standards Program

- It is expected the number of continent-wide standards development projects will 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 standards projects will consist primarily of conducting enhanced periodic reviews on existing 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 (RRM), Compliance Analysis and Certification, and Compliance Assurance) and support from across the ERO Enterprise.
- During the enhanced periodic review of ERO standards, any associated regional standards will be reviewed for potential incorporation as variances or as improvements to the continent-wide requirements. Regional and NERC standards development processes may require modification to accomplish efficiently this task. Each Regional Entity will work with NERC and possibly other Regional Entities on projects where there is a regional standard/variance. Regional standards development activity will be driven by requests the Regional Entity may receive or reliability issues the Regional Entity may identify. Regional standards development activity is expected to remain low.
- In coordination with Standard Drafting Teams and consistent with current approaches, Regional Entities may 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 within their respective regions. Additionally, following FERC approval, NERC and the Regional Entities collectively will assist the transition of standards to compliance monitoring and enforcement by providing knowledge that supports industry and auditor training, or providing information regarding the intent of the standard.
- The number of interpretations are expected to remain low. However, guidance requests associated with the implementation of Standards may increase.

Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs

[40] These statements, which are generally organized by program area, are intended to help guide resource allocation decision-making in the development of the 2017 BP&Bs.

Compliance and Enforcement

- The implementation of the risk-based compliance monitoring and enforcement program (CMEP) will continue to require the allocation of dedicated resources from both NERC and the Regional Entities for both compliance and enforcement. Regional Entities created a plan in 2016 to complete Inherent Risk Assessments (IRAs) for all their Reliability Coordinators, Balancing Authorities, and Transmission Operators and will require resources to complete the remaining IRAs in 2017. In addition, Regional Entities will require resources to update previously done IRAs based on identified triggers, and focus on creating compliance oversight plans that include compliance monitoring tools, the frequency of compliance monitoring, and the standards that are to be monitored as well as the depth of testing of those standards.
- NERC and the Regional Entities will continue the 2015-2016 ERO Enterprise exercises to evaluate business practices, implementation, and consistency within risk-based compliance monitoring.
- NERC and the Regional Entities will participate in ERO Enterprise consistency activities, including providing input into standards development.
- NERC and the Regional Entities are planning to support the training and education requirements and guidelines necessary to meet the criteria set forth by the *ERO Enterprise Compliance Monitoring and Enforcement Manual* and the *Competency Guide*.
- The suitability of software systems currently used for compliance, registration, analysis and tracking will continue to be evaluated from a strategic perspective, which may result in changing or replacing existing systems in the future. However, until such changes have been identified, reviewed and approved by the ERO Enterprise Technology Leadership Team and EROEMG for implementation, NERC and the Regional Entities should continue to maintain the necessary resources to support existing systems.
- Planning and operating standard violations are expected to level off or continue decreasing as most registered entities have been audited and thus have a greater understanding of compliance expectations, and the standards have matured.
- Compliance personnel will need to continue to support the implementation of cyber-security reliability standards version 5 (CIP V5):
    - NERC will lead the CIP V5 training development, coordination, and facilitation for the ERO Enterprise CIP auditors and industry outreach. ERO Enterprise CIP auditors will support these activities in collaboration with NERC to ensure appropriate knowledge and guidance is developed, understood by industry, and administered.
    - The allocation of resources in 2017 and 2018 should be responsive to continued implementation by registered entities of new versions of the CIP Standards, while recognizing that the risk-informed focus will be on monitoring “high” and “medium” impact requirements.
- Additional resource allocation may be necessary for increased Physical Security compliance monitoring activities for CIP-014.
- ERO Enterprise CMEP staff, particularly staff with visibility into risks occurring in the field, will provide feedback to the ERO Enterprise. This feedback may include information on risks seen in the field that are not addressed by a standard as well as information on where a standard is too broad. ERO Enterprise CMEP staff will participate in the development of a solution, regardless of whether the solution is a standard or other solution.

- ERO Enterprise CMEP staff will provide input for standards development teams on the risks seen in the field relating to a standard under development, as well as how a standard would be monitored.

Organization Registration and Certification

- Two central reforms have been identified as a result of the completion of the risk-based registration activity in 2015:

  1. Modifications to the NERC Registry Criteria have been approved, including the elimination of three functional entities (Purchasing-Selling Entities, Interchange Authorities, and Load-Serving Entities), modifications to the threshold criteria for Distribution Providers, and alignment of five registration categories with the BES definition.

  2. The NERC-led panel, which establishes subset lists of applicable reliability standards for registered entity functions (e.g., Under-Frequency Load Shedding-only Distribution Providers), has been incorporated into the rules.

These reforms strengthen the registration process and are important milestones in NERC's approach to managing risks to reliability. Deployment and implementation of these revisions began in 2015, with continued work in 2016 and possibly 2017.

- No further enhancements are anticipated to support the ongoing next phases of the risk-based registration activity.
- Based on the 2015 technical assessment of the Phase 2 registered functions (Transmission Operator, Transmission Owner, Generator Owner, and Generator Operator), development of subsets of standards are not necessary.
- The certification and registration programs will be assessed in 2016, which may result in modifications to the program in 2017.
- The activities associated with the implementation of the BES definition have decreased, therefore no additional resource demands are expected in the registration area.
- Planned oversight activities for 2017 will be aligned with the ERO Enterprise Operating Model and should not affect 2017 resource allocation and should have little effect on overall NERC resource requirements. NERC understands that each Regional Entity will need to evaluate its individual resource needs and allocations.

Reliability Assessment and Performance Analysis Program (RAPA)

- Support and leadership to (1) the Planning Committee and (2) standing committees' subcommittees, working groups, and task forces serving the standing committees will continue.
- NERC and the Regional Entities will continue to focus resources on high quality reliability assessments and performance analysis, including:
  - Development and implementation of expanded and enhanced enterprise-based data collection and analysis systems, and capabilities for performance analyses. This includes TADS, GADS, NERC RAS data, and misoperations data;
  - Support of the integration of RAPA information systems for assessments and associated data requirements, with focus on objective and technically sound reliability assessments supporting delivery of high quality reports (e.g., long-term, short-term, special or scenario assessments, and 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 reliability impacts of new technologies, changing resource or demand resource composition, and environmental related regulations or legislation;
  - Providing technical resources and expertise to perform analyses as needed, including to support and identify risk priorities for standards development, compliance, and enforcement activities;
  - Development 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 reliability assessments (6-18 month horizon replacing the current summer and winter assessments), which focus on specific reliability risk areas and geographic areas with specific reliability concerns, while also allowing for regional assessments;
  - Support of the common approach developed for NERC reliability assessments to ensure consistent treatment of resource and reliability evaluations.

- NERC and the Regional Entities will advance analytical capabilities for identifying and determining reliability risks and conducting various reliability assessments by:
  - Integrating the analysis and measures of essential reliability services (ERS) into the Long-Term Reliability Assessment. The process encompasses new data collection and analysis approaches needed to address assessment objectives of identifying reliability issues due to a changing resource mix;
  - 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;
  - Requiring advanced statistical analysis tools and objective expert input to support them for probabilistic assessments.

- NERC will support the maintenance of the BESnet application and manage processing of the Regional BES Exception Requests (ERs), including technical validation of the definition and exception requests, self-determined notification submittals, periodic reviews of network changes affecting BES determinations, as well as requests for registration and certification reviews. The Regional Entities will continue to process BES ERs per guidelines established in the NERC Rules of Procedure.[41]

- NERC and Regional Entities' resources (through the case building designee agreements) will support the Planning Coordinators' 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. These models will integrate needed elements that address reliability behavior of changing resource mix and technology of both generation and loads, including:

[41] NERC Rules of Procedure

  - Development of a process to ensure the continued compilation and creation of annual sets of seasonal and future steady state and dynamic simulation model cases;
  - 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;

- NERC and the Regional Entities will work collaboratively to enhance the ERO Enterprise's capability for post event analysis, including:
  - Development of a process to ensure the compilation and creation of steady state and dynamic simulation model cases for use in the investigation and analysis of major power system disturbance events;
  - Development and tracking of metrics that demonstrate the accuracy of the powerflow and dynamics models to replicate actual system conditions and reliability behavior;
  - Evaluation of event disturbances using phasor measurements and other methods to assess sufficiency of data and models.
- NERC and the Regional Entities may require contractor and consultant services to maintain continued support and technical expertise associated with activities listed in the above assumptions and with supporting special assessment, scenario, or other technical research efforts. It could potentially impact both NERC and Regional Entity resource allocation:
  - If significant events occur, contractor services may be required to support wide-area system analyses and root cause evaluations.
  - Contractor services may be necessary to support special assessment analyses (e.g., EPA 111(d) evaluation or ERS), scenario analyses (e.g., polar vortex-like severe event analyses and gas-electric interdependence), and other technical research efforts (e.g., similar to geomagnetic disturbances, and FAC-003 Vegetation Management).

Training, Education, and Operator Certification Program

- NERC will continue to budget for the unified learning management system (LMS) focused initially on Regional Entity audit staff, with near-term consideration for risk-based compliance monitoring and enforcement related staff. Future inclusion of other ERO functional areas is expected as potential requirements present themselves during system development. NERC will work with the Regional Entities to consolidate training resources and promote better coordination, planning, delivery and management of training and outreach efforts across the enterprise without adversely impacting Region-specific training requirements.
- The implementation of CMEP staff training and competencies are expected to influence the allocation of training resources throughout the enterprise. NERC will continue the development of compliance training modules with assistance of qualified subject matter experts from the Regional Entities and incorporation of outside expertise/services.
- An allocation of additional resources may be required to support certain training and outreach activities of the risk-based CMEP:
  - Regional Entities should allocate resources to meet the requirements for the compliance and enforcement staff that are associated with the implementation of the risk-based CMEP.
- The Regional Entities, in collaboration with NERC, are expected to help assess and determine training and outreach needs. This includes flexibility in approach between Regional Entities, and

anticipating areas of support for their staff and stakeholders for standards, compliance monitoring and enforcement, situation awareness and event analysis, and information technology. Addressing these needs will likely require additional resource allocation and budgeting considerations.

- NERC, in collaboration with Regional Entities, will develop and deliver additional CIP V5 training to support the transition. This may require consideration for additional funding of the NERC training and education budget.
- The Operating Personnel Certification program is expected to remain at a steady state with no additional resources required from the Regional Entities.
- Contractor and consultant services may be necessary to maintain the continued support and technical expertise associated with some enterprise training, outreach and education activities.

Situation Awareness and Infrastructure Security (including Events Analysis)

- NERC will continue to provide required support and leadership for the Operating Committee and the Critical Infrastructure Protection Committee, and standing committees, subcommittees, working groups, and task forces serving the standing committees. Regional Entity involvement is expected to remain at current levels with no additional resources required from the Regional Entities.
- Registered Entity participation in the ERO Event Analysis Process, which involves active participation by Regional Entity staffs, will continue at or above current levels through 2016.
- NERC will continue to budget and incur costs to operate and maintain the software application known as Situational Awareness for FERC, NERC, and Regional Entities, Version 2 (SAFNRv2) for situation awareness, and The Event Analysis Management System (TEAMS) for Events Analysis. The allocation of additional resource investments are expected to maintain the capabilities of SAFNRv2 throughout the planning period. Any such investments will be NERC funded and not result in an allocation of cost to the Regional Entities.
- Regional Entities will continue to budget for event analysis and situational awareness activities based on their respective Region's historical workload, as they did in the past. Some Regional Entities will continue to allocate resources as part of the activities accounted for under their RAPA program, and should clearly delineate where the activities' resources are budgeted.
- Regional Entities will support critical infrastructure security activities in the context of situation awareness, using those designated resources, unless specifically budgeted and managed elsewhere.

Electricity Information Sharing and Analysis Center (E-ISAC)

- NERC will continue to fund, operate and maintain the E-ISAC, with no increased cost to the Regional Entities.
- NERC will continue to fund and conduct the Grid Security Exercise program, with no increased cost to the Regional Entities. Analysis and planning activities will occur during even-numbered years and execution of the exercise will take place in odd-numbered years.
- NERC will continue to fund and conduct the Grid Security Conference as an annual event. Other than funding registration fees for individual attendees from their Regional Entity, no Regional Entity funding is anticipated.

Information Technology and Project Management Office (PMO)

- NERC and the Regional Entities will work collaboratively to refine existing strategies and governance and procurement practices applicable to the development, operation, and maintenance of enterprise architecture, including software and data systems supporting both NERC and Regional Entity operations.
- NERC's BP&B will include ongoing funding support for the development, operation, and maintenance of ERO Executive Management Group (EMG)-approved enterprise applications. Enterprise application funding in any given year will be subject to the budget and funding limits set forth in NERC's approved BP&B. Regional Entities should include appropriate funding for applications and supporting systems designed to satisfy Regional business needs (if not within the mutually agreed upon scope of the ERO Enterprise applications that are funded by NERC).
- Regional Entities may be required to provide or augment business teams to help develop application business requirements and to test business functionality within the ERO applications.
- Ongoing investments will be required to develop, implement, and maintain enhancements to the NERC and Regional Entity websites, ERO applications, and ERO data repositories, which are required to improve access to information and data. NERC and the Regional Entities will separately fund any enhancements to their own websites.

ERO Enterprise-wide Risk Management

- A common ERO Enterprise risk management framework commenced in 2014 to focus on identifying, assessing, prioritizing, and mitigating risks associated with the performance of both NERC and the Regional Entities. This will be a multi-year activity with the project expected to reach steady state by 2017.
- NERC's Director of Risk Management and Internal Audit is responsible for the overall development of this framework, with the approval of the ERO Regional Executives and under the oversight of NERC's Enterprise Wide Risk Management Committee.
  NERC and the Regional Entities will continue to devote resources to implement this framework. Activities include validating and prioritizing risks for EROEMG review and approval. The results will serve as an input into the NERC's future audit plans, which are reviewed and approved by the NERC Board of Trustees Enterprise Risk Management Committee. Regional Entities may add risk management and internal control resources as needed.

Exhibit B – Application of NERC Section 215 Criteria

DISCUSSION OF HOW THE NERC MAJOR ACTIVITIES IN THE 2017 BUSINESS PLAN AND BUDGET MEET THE NERC WRITTEN CRITERIA FOR DETERMINING WHETHER A RELIABILITY ACTIVITY IS ELIGIBLE TO BE FUNDED UNDER FEDERAL POWER ACT SECTION 215

Introduction

This Exhibit discusses how the major activities in NERC's 2017 Business Plan and Budget meet the NERC written criteria for determining whether a reliability activity is eligible to be funded under §215 of the Federal Power Act ("FPA §215"). This Exhibit is intended to satisfy Recommendation No. 38 resulting from the financial performance of NERC conducted by the Commission's Division of Audits ("DA") in 2012-2013 and adopted by the Commission in its November 2, 2012 order on NERC's 2013 Business Plan and Budget.[1] NERC submitted the written criteria to the Commission in a compliance filing dated February 21, 2013 in Docket No. FA11-21-000.[2] The Commission approved the NERC written criteria, with modifications, in an order issued in that docket on April 18, 2013.[3] The NERC written criteria as used in this Exhibit incorporate the modifications specified in the Compliance Order.[4]

II. Reliability Standards Program 2017 Major Activities

The major activities of the Reliability Standards Program are described at pages 24-26 of the 2017 Business Plan and Budget. The Reliability Standards Program carries out the ERO's responsibility to develop, adopt, obtain approval of, and modify as and when appropriate, mandatory Reliability Standards for the reliable planning, operation, and critical infrastructure protection of the North American BES. The major activity areas for this program include (1) providing project management and leadership to the reliability standard development process to deliver high-quality, continent-wide reliability standards, both new and modified, including standard development outreach activities, facilitation of Standard Drafting Team activities, drafting support, assisting Standard Drafting Teams in adhering to the processes in the *Standard Processes Manual*, and ensuring that the quality of documents produced are appropriate for approval by industry and the NERC Board; (2) facilitating continent-wide industry engagement in the standard development processes; and (3) conducting industry balloting on standards, disseminating information on standards and the standard development processes, and supporting regulatory filings and proceedings relating to standards. Additionally, the Reliability Standards Program provides technical advice and final quality review for Regional Entity standards development processes, presents proposed regional standards to the

[1] *North American Electric Reliability Corporation, Order Accepting 2013 Business Plan and Budget of the North American Electric Reliability Corporation and Ordering Compliance Filing*, 141 FERC ¶ 61,086 (2012) ("2013 Budget Order"). Recommendation 38, as adopted in the 2013 Budget Order, is: "In its annual business plan and budget filings, [NERC should] provide an explanation as to why the proposed activities to be undertaken by each program area for the budget year are statutory, including, at a minimum: a description and the purpose of the major activities to be taken by each program area and an explanation for why the activity is a statutory activity." *Id.* at P 16.

[2] *Compliance Filing of the North American Electric Reliability Corporation in Response to Paragraph 30 of November 2, 2012 Commission Order – NERC Written Criteria for Determining Whether a Reliability Activity is Eligible to be Funded Under Federal Power Act Section 215*, filed February 1, 2013 in Docket No. FA 11-21-000 ("February 1, 2013 Compliance Filing").

[3] *North American Electric Reliability Corporation, Order on Compliance*, 143 FERC ¶ 61,052 (2013) ("Compliance Order").

[4] For ease of reference, the complete NERC written criteria, as modified in accordance with the Compliance Order, are provided at the end of this Exhibit.

NERC Board, and prepares submissions for approval of regional standards to the applicable regulatory authorities in the U.S. and Canada.

For 2017, the major activities of the Reliability Standards Program will focus on (1) selection of standards projects to be undertaken based on the nature of the reliability issue, cost compared to risks, and whether a standard or another solution is most appropriate to address the issue; (2) addressing Commission directives and responding to Commission orders as necessary through the standards process; (3) performing enhanced periodic reviews of standards; and (4) facilitating smooth transitions to new standards through developing guidelines, webinars, and other activities to support auditor and industry training for new standards. Identification of need for new standards projects will be based on sources such as Commission directives and reliability risks identified by the Reliability Risk Management Process or the Reliability Issues Steering Committee (RISC).

The major activities of the Reliability Standards Program satisfy the following criteria:

I.A: Is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure (ROP)?

I.B: Is the activity necessary or appropriate for providing guidance and assistance to Regional Entities in carrying out Regional Reliability Standards development activities?

I.C: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated?

I.D: Is the activity necessary or appropriate for the provision of training and education concerning Reliability Standards development processes, procedures, and topics for/to (i) NERC personnel, (ii) Regional Entity personnel, (iii) industry personnel?

II.F.1: Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (ii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as (1) Requirements of Reliability Standards, including how to comply and how to demonstrate compliance? This includes development of guidance and interpretation documents.

IV: Is the activity one that was required or directed by a Commission order issued pursuant to §215? (Reliability Standards development projects re often initiated in response to directives in Commission orders).

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for these major activities are §300 and Appendix 3A.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18

C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

X. Is the activity necessary or appropriate for the analysis and evaluation of activities encompassed by one or more of the other criteria for the purpose of identifying means of performing the activities more effectively and efficiently?

III. Compliance Monitoring and Enforcement and Organization Registration and Certification Program Area 2017 Major Activities

The major activities of the Compliance Monitoring and Enforcement and Organization Registration and Certification Program Area are described at pages 28-30, 31-33, and 35-41 of the 2017 Business Plan and Budget. This Program Area is comprised of three operational groups: (1) Compliance Assurance (addressing compliance monitoring), (2) Reliability Assurance (addressing assurance, organization registration and certification), and (3) Compliance Enforcement.

The Compliance Assurance group works collaboratively with the Regional Entities to ensure effective implementation of risk-based compliance monitoring under the Compliance Monitoring and Enforcement Program ("CMEP") across the entire ERO Enterprise. This group's activities include the following major activities and functions: (1) ensuring that Regional Entities monitor registered entities for compliance according to their specific facts and circumstances, developing customized compliance oversight plans (COPs) for each registered entity based on its inherent risk assessment (IRA); (2) overseeing Regional Entities' IRAs of registered entities; (3) oversight of the quality implementation of the risk-based compliance monitoring program; (4) development of the annual CMEP Implementation Plan; (5) oversight of use of necessary compliance-related processes, procedures, IT platforms, tools and templates; (6) development and delivery of education and training for ERO Enterprise staff; (7) conducting CIP V5 training and education programs and other outreach that support industry compliance and integration of risk assessment and internal controls; (8) coordinating with the NERC Standards department for standards development to provide compliance information, statistics, and perspectives to standard drafting teams to foster development of standards that provide increased reliability benefit and clarify compliance risks, and to assist in smooth transitions for standards from development to enforceability, including by providing draft compliance monitoring guidance, information on how compliance with draft standards will be determined, and input on auditability and enforceability; (9) supporting Regional Entity and industry committees, working groups and task forces, such as the NERC Compliance and Certification Committee; (10) industry training for every Reliability Standard approved by the Commission, as well as industry-focused outreach events and webinars on risk-based CMEP activities; and (11) promoting registered entities' development of effective compliance programs and internal controls.

The ongoing and new major activities of the Compliance Assurance group for 2017 will include: (1) continuing to mature the risk-based compliance program, including fully developing customized COPs for registered entities; (2) working with NERC Enforcement and IT and with Regional Entity staffs on improvements in the existing compliance reporting, analysis, tracking system and other compliance tools supporting risk-based activities; (3) supporting successful implementation of CIP V5 standards and subsequent enhancements that become effective in 2017 and beyond; (4) continuing to monitor and

support effective implementation and monitoring of the Physical Security Reliability Standard; (5) initiating a training program to support implementation of common audit procedures for each standard; and (6) continuing to integrate standards and compliance functions for clear stakeholder implementation, including through a common set of Reliability Standards Audit Worksheets, measures, or successors for all standards and in initiating a compliance phase-in learning period for all standards.

The Compliance Analysis, Certification and Registration group is responsible for a range of requirements and activities embodied in Section 500 and Appendices 5A and 5B of the NERC ROP, including providing technical resource support to standards development, compliance monitoring, and enforcement; ensuring that all entities impacting the BES are registered commensurate with risk; ensuring all Reliability Coordinators ("RC"), Balancing Authorities ("BA") and Transmission Operators ("TOP") are certified; conducting industry reliability assurance activities; and ensuring that compliance gaps identified in reportable events are assessed and addressed if appropriate. Major activities of this group include (1) registration of BES users, owners, and operators who are responsible for compliance with Commission-approved Reliability Standards; (2) evaluating and certification of the competency of RCs, BAs and TOPs; (3) conducting activities to reasonably assure the ERO that certain actions have been taken as reported in response to NERC Alerts or guidance to industry; (4) providing oversight of Regional Entity implementation of regional registration, compliance, certification, investigation, and complaint programs and processes; (5) conducting investigations of identify Possible Violations of Reliability Standards in response to complaints, BES disturbances, or other triggers, including participating on all Regional Entity-led investigations and observing as requested on Commission-led reliability investigations and inquiries; and (6) working with Regional Entity staff to confirm that qualified events and disturbances are evaluated against the relevant Reliability Standards and to ensure formal compliance monitoring occurs if indicated. Specific major activities of Compliance Analysis, Certification and Registration for 2017 will include continuing to work with the NERC-led panel to review registered entities for deregistration or applicability to a reduced number of Reliability Standards; and implementing registration program improvements and certification program improvements identified in 2016, including conducting training as necessary.

The Compliance Enforcement department is responsible for overseeing enforcement processes, the application of penalties or sanctions, and activities to mitigate and prevent recurrence of noncompliance with Reliability Standards. The Department works collaboratively with the Regional Entities to ensure consistent and effective implementation of the risk-based CMEP, including evaluating the consistency of disposition methods including assessment of penalties or sanctions. It also focuses on ensuring that the ERO Enterprise dedicates resources to the matters that pose the greatest risk to reliability. The Compliance Enforcement department monitors Regional Entities' enforcement processes and provides oversight over the outcomes of such processes, to ensure due process, identify best practices and process efficiency opportunities, and promote consistency among Regional Entities' business practices; collects and analyzes compliance enforcement data and trends to assist with identification of emerging risks and help to inform development of enforcement policy and processes; files notices of penalty ("NOP") and other submittals associated with noncompliance discovered through Regional Entity compliance, monitoring and enforcement activities; processes and files NOPs and other submittals discovered through NERC-led investigations and audits; collaborates with other NERC departments, including Compliance Assurance, Reliability Standards and Regional Entity Coordination; and delivers training of the ERO Enterprise staff and outreach to registered entities on compliance and enforcement topics. Compliance Enforcement also conducts outreach activities that focus on self-logging, compliance exceptions, risk elements, CIP V5, IRAs, and internal controls.

During 2017, the Compliance Enforcement department will continue to focus on the successful implementation of, as well as refining and improving, the risk-based CMEP. The major activities of Compliance Enforcement will include refining and improving risk-based CMEP processes; implementing in a transparent manner the risk-focused ERO Enterprise enforcement philosophy; expanding the feedback loop of information from Enforcement to Standards and other program areas; and working with Compliance Assurance, IT, and Regional Entity staff regarding improvements in the existing compliance, reporting, analysis system and other compliance tools to support risk-based activities.

The major activities of the Compliance Monitoring and Enforcement and Organization Registration and Certification Program Area satisfy the following criteria:

I.A: Is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure?

I.C: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated?

II.A: Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

II.B: Is the activity necessary or appropriate for the Certification of Reliability Coordinators, Transmission Operators and Balancing Authorities as having the requisite personnel, qualifications and facilities and equipment needed to perform these reliability functions in accordance with the applicable Requirements of Reliability Standards?

II.D: Is the activity necessary or appropriate for conducting, participating in or overseeing compliance monitoring and enforcement activities pursuant to the NERC ROP and (through the Regional Entities) the Commission-approved delegation agreements?

II.E: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information to monitor and enforce compliance with Reliability Standards, including evaluating the effectiveness of current compliance monitoring and enforcement processes, the need for new or revised compliance monitoring and enforcement processes, and the need for new or different means of training and education on compliance with Reliability Standards.

II.F: Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as: (1) Requirements of Reliability Standards, including how to comply and how to demonstrate compliance? This includes development of guidance and interpretation documents. (2) Compliance monitoring and enforcement processes, including how to conduct them, how to participate in them, and the expectations for the process? This includes development of guidance documents. (3) Disseminating, through workshops, webinars,

Advisories/Recommendations/Essential Actions, and other publications, "lessons learned" information on compliance concerns and reliability risks obtained through compliance monitoring and enforcement activities, monitoring and investigation of Bulk Power System major events, off-normal occurrences and near miss events, and other Bulk Power System monitoring activities? (4) Registered Entity internal processes for compliance with Reliability Standards, such as development, implementation and maintenance of internal reliability compliance programs?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for these major activities are §400 and 500 and Appendices 4B, 4C, 5A, 5B and 5C.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

IX: Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in the activities encompassed by one or more of the other criteria?

X: Is the activity necessary or appropriate for the analysis and evaluation of activities encompassed by one or more of the other criteria for the purpose of identifying means of performing the activities more effectively and efficiently?

IV. Reliability Assessment and System Analysis Program 2017 Major Activities

The major activities of the Reliability Assessment and System Analysis (RASA) Program are described at pages 43-47 of the 2017 Business Plan and Budget. The RASA Program carries out the ERO's responsibility to conduct assessments of the reliability and adequacy of the BES to provide insight and guidance about reliability risks and performance improvements. RASA focuses on developing a technical framework and understanding of the reliability risks facing the industry. The principal activity areas of the RASA Program include: independent assessments and reports on the overall reliability, adequacy, and associated reliability risks that could impact the upcoming summer and winter seasons and the long-term (e.g. 10-year) planning horizon; development of focused reliability assessments based on emerging reliability risks and other reliability issues garnering an in-depth analysis; performance analysis and recommendations of historical reliability and associated trends, relying on data integrity and consistent methodology, supporting credible recommendations and guidance; reliability assessment and interconnection-wide analysis for analyzing steady-state and dynamic conditions, including frequency, Essential Reliability Services, and stability aspects; support for development and improvement of long-term sustainable interconnection-based power flow, dynamic and load models, and technical studies and practices to use these models; advancement of industry and the ERO's understanding of power system characteristics and behaviors by gathering larger PMU datasets of data for advanced data analytics and modeling improvements; reliability risk program management for identifying and improving key risk areas using analyses of reliability gaps, risks, controls, and management efforts, as well as integration with the RISC, Long-Term Reliability Assessment, short-term (seasonal) assessments, and State of Reliability reports; management of reliability risk program priorities to align with the Strategic Plan and business

plan and budget for appropriate level of resources, timing, completion and execution; and establishing reliability leadership and consistent, technically sound guidance and recommendations that position industry and policy-makers to enhance reliability through effective outreach and communications.

The RASA Program works with industry leaders to create a reliability strategy that is relevant, timely, and effective at addressing the most important reliability risks, through understanding key information identified through analysis and assessment efforts; extracting and prioritizing the associated reliability risks from that information; sharing and integrating risk analysis insights across the ERO Enterprise; and translating that knowledge into actionable guidance and recommendations for NERC management, the Board, and entities, and government policy makers. Reliability assessments evaluate the expected reliability behavior of the BPS through extensive deterministic and probabilistic analyses to identify potential reliability conditions that could compromise reliability. RASA both assesses and reports on the reliability, adequacy and associated risks that could impact short-term and long-term study periods, and conducts special reliability assessments and identifies recommendations and guidance actions that may be warranted to lessen identified risks or enhance overall reliability. RASA also coordinates forecast reliability data between planning areas, the Regional Entities, and government organizations, and produces the Electricity Supply and Demand data base. A significant ongoing effort involving RASA, Regional Entity staff, and stakeholders focuses on continued development of effective Essential Reliability Services, leading to defined Essential Reliability Services, an evaluation of initial metrics and data compilation of actual performance, and ongoing assessment.

RASA works closely with other organizations such as the Electric Power Research Institute (EPRI), Department of Energy (DOE), Institute of Electrical and Electronics Engineers (IEEE), Institute of Nuclear Power Operations (INPO), North American Transmission Forum (NATF), North American Generation Forum (NAGF), Canadian Electricity Association (CEA), Interstate Natural Gas Association of America, and Natural Gas Supply Association, on a number of energy industry reliability issues such as geomagnetic disturbances, vegetation management, variable generation integration, and interdependency of gas and electric systems.

The ongoing and new major activities of the RASA Program for 2017 include: (1) Issuing assessment reliability reports, guidelines, recommendations and alerts as needed (including verification and validation of data and information through Regional Entities and technical committees); preparing the long-term (10-year) and short-term (2 to 4 seasonal or shoulder period analyses) reliability assessments; conducting special assessments addressing key reliability risks, including potential environmental regulation impacts to BPS reliability and Essential Reliability Services issues (frequency response and controls, natural gas availability and pipeline outage assessment, and nuclear plant retirements); and preparing an annual State of Reliability Report; (2) Preparing a frequency response analysis report (to the Commission and to support Reliability Standard BAL-003 and the annual Interconnection Frequency Reporting obligations (IFRO)); meeting regulatory requirements per BAL-003-1 and other analyses and studies of frequency response. (3) Supporting a risk registry and systematic prioritization process consistent with the RISC framework and supporting BES risk profile measurements and assessment of standards. (4) Executing integrated risk control strategies and plans across the ERO Enterprise to address the highest-priority existing or emerging risks to BES reliability, and explicitly measure the results. (5) Supporting Reliability Standards development and responses to Commission directives by providing technical and system analysis expertise. (6) Supporting the technical foundation development for Reliability Standards to address deficiencies or needs identified by RASA. (7) Advancing NERC's analytical capability for identifying reliability risks and conducting various reliability assessments, including by integrating Essential Reliability Services analysis and measures into long-term reliability

assessment, proving advanced power flow and stability analysis tools for transmission/deliverability assessments and studies, and providing advanced statistical tools for probabilistic assessments. (8) Providing support and leadership to the NERC Planning Committee and to standing committees and subcommittees, working groups, and task forces. (9) Assisting in the development of approaches to registration and providing input (based on reliability trends, risks, and historical performance information) to NERC staff in support of the development CMEP risk elements, to ensure that the compliance focus remains on the most critical entities and associated Reliability Standards. (10) Supporting major event investigations, analyses, and reporting of major findings, recommendations, and lessons learned that will improve reliability. (11) Building and sustaining an ERO Enterprise Reliability Assessment and Performance Analysis team that encompasses risk-informed approaches and structured methods to identify and address reliability risks. (12) Implementing effective oversight and tracking of various technical aspects of reliability, including frequency response performance, application of TPL footnote b adoption, and root cause applications, to assessments and analyses. (13) Supporting interconnection-wide model-building groups by providing feedback on model quality and fidelity. (14) Developing a Reliability Guideline on Power Plan Model Verification, including providing industry support with webinars and training, supporting the user group in the NERC Synchronized Measurement Subcommittee, and developing a structured approach to evaluate and improve system models, model validation, system analysis, and assessments. (15) Expanding use of synchrophasor technology for power plant model verification, compliance with MOD-026/-027 standards, and internal system and model analysis. (16) Broadening understanding of inter-area, local, and forced oscillations in all interconnections, and using wide-area synchrophasor data to provide industry with better understanding of phenomena, available tools, and findings. (17) Driving education of dynamic load modeling and development of improved load models, and supporting compliance with Reliability Standard TPL-001-4, including through a Reliability Guideline on Load Comparison, Technical Reference Document on Load Modeling, a workshop on Dynamic Load Modeling and FIDVR, driving next generation dynamic load models for all software platforms, model benchmarking and testing for more robust tools and models, and developing default data sets and testing with industry to ensure robust starting points. (18) Proactively seeking to address deficiencies in interconnection-wide models used by Transmission Planners and TOPs. (19) Ensuring models can sufficiently recreate plant behavior, through exploring known/historical events and required modeling improvements to accurately represent pre- and post-events. (20) Working with interconnection model designees to positively impact case quality and robustness for industry's benefit. (21) Supporting study and policy development related to end-use load behavior, and advocate for grid-friendly load response.

During 2017, RASA will continue to work with the Regional Entities on implementation of the BES definition and processing BES Exception Requests, through reviews, evaluations, and confirmations of proposed changes to BES elements by registered entities and use of the BESnet tool.

The major activities of the RASA Program satisfy the following criteria:

I.A: is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure?

I.C.1: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as: (1) Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and

analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

II.A: Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

III.A: Is the activity necessary or appropriate for the preparation or dissemination of long-term, seasonal, and special assessments of the reliability and adequacy of the Bulk Power System?

III.B: Is the activity necessary or appropriate for measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

III.F: Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

IV: Is the activity one that was required or directed by a Commission order issued pursuant to §215? (FERC orders directed NERC to develop and implement a revised definition of "Bulk Electric System" and a procedure for requesting and receiving exceptions from the BES definition, and subsequently approved NERC's proposed revised BES definition and its proposed BES exception procedure.)

V. Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for this major activity are §801-806 and 809-810 and Appendix 5C.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

IX: Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

X: Is the activity necessary or appropriate for the analysis and evaluation of activities encompassed by one or more of the other criteria for the purpose of identifying means of performing the activities more effectively and efficiently?

V. Performance Analysis 2017 Major Activities

The major activities of the Performance Analysis (PA) group are described at pages 49-51 of the 2017 Business Plan and Budget. The PA group carries out the ERO's responsibility to conduct analyses of

the reliability and adequacy of the BES, which are used to provide insight and guidance about reliability risks, performance improvements, and reliability performance issues and areas of concern, including with respect to system, equipment, entity and organizational performance that may indicate a need to develop remediation strategies, action plans, or data used to revise or retire Reliability Standards or consider new Reliability Standards. PA focuses on developing a technical framework and understanding reliability risks facing the industry.

PA collects transmission outage, generator performance, demand response, and protection and control systems misoperations data in a common format using various industry databases; this data is used to develop and report grid metrics that analyze outage frequency, duration, causes, and other factors related to transmission and generator performance and automatic power system protection and control effectiveness. Trends, findings and recommendations from PA serve as technical input to Reliability Standards and to standards project prioritization, compliance process improvements, event analyses, reliability assessment, and critical infrastructure protection efforts. In 2017, PA will add wind generator data to the data collected. The analyses and results collected and produced are reported in the annual State of Reliability Report, which in 2017 will begin to reflect post-seasonal reliability review, insights from analysis of transmission, generator, and demand response data systems, and integration of event analysis and misoperations. PA also supports the NERC System Protection & Controls Subcommittee.

PA works closely with other organizations including EPI, DOE, IEEE, INPO, NATF, NAGF, and CEA, on a number of fronts, including the Transmission Availability Data System (TADS), Generator Data Availability System (GADS), and Demand Response Availability Data System (DADS).

PA's ongoing and new major activities for 2017 will include the following: (1) Issuing reliability assessment reports, guidelines, recommendations, and alerts as needed, including verification and validation of data and information through Regional Entities and technical committees, through the annual State of Reliability Report and a frequency response analysis. (2) Overseeing TADS, GADS and TADS as well as reliability metrics and protection and control systems misoperations data, including strengthening data collection and validation processes by designing, creating, testing and implementing data-checking systems for reliability assessment, system analysis and risk analysis, and providing periodic updates on trends and measures of BES reliability. (3) Serving as the business lead and working with IT, as necessary, to have in place the required tool for GADS Wind data. (4) Supporting Reliability Standards development and responses to Commission directives by providing technical and analytical expertise. (6) Assisting in the development of approaches to registration and providing input (based on reliability trends, risks, and historical performance information) to NERC staff in support of development of CMEP risk elements and ensure that the compliance focus remains on the most critical entities and associated Reliability Standards. (7) Conducting major event investigations, analyses, and reporting of major findings, recommendations, and lessons learned that will improve reliability.

The major activities of PA satisfy the following criteria:

I.A: is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure?

I.C.1: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as: (1)

Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks? (2) Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences and near miss events?

II.A: Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

III.A: Is the activity necessary or appropriate for the preparation or dissemination of long-term, seasonal, and special assessments of the reliability and adequacy of the Bulk Power System?

III.B: Is the activity necessary or appropriate for measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

III.F: Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

V. Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for this major activity are §801-811 and Appendix 8.)

IX: Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

VI. Reliability Risk Management (Situation Awareness and Event Analysis) 2017 Major Activities

The major activities of the Reliability Risk Management ("RRM") group, which is comprised of the Situation Awareness Department and the Event Analysis Department, are described at pages 53-55and 57-58 of the 2017 Business Plan and Budget. The RRM group carries out the ERO's responsibility to perform assessments (including real-time and near-real-time continual awareness, detailed analysis of significant events, and longer-term broad performance assessments) of the reliability and adequacy of the BES, including identifying potential issues of concern relating to system, equipment, entity, and human performance. RRM has six primary functions: (1) BES awareness, (2) event analysis and determination of root and contributing causes, (3) assessment of human performance challenges that affect BES reliability and identification of improvement opportunities, (4) continent-wide analysis and reporting of BES performance, (5) support of the NERC Operating Committee, and (6) support of the NERC Critical Infrastructure Protection Committee. Through awareness and continuous assessment, RRM identifies potential reliability risks to the BES, analyzes events in detail, ensures that industry is well informed of system events, emerging trends, risk analysis, and lessons learned, and provides data and analysis to inform other aspects of NERC's statutory functions.

The Situation Awareness department along, with the Regional Entities, monitors BES conditions, significant occurrences and emerging risks, and threats across the 14 Reliability Coordinator regions in North America. Situation Awareness also supports development and publication of NERC Alerts and awareness products, and facilitates information sharing among industry, Regions and government during crisis situations and major system disturbances. Situation Awareness is engaged in enhancement, replacement, streamlining or modification of several reliability-related situation awareness and monitoring tools, including SAFNRv2, operation and maintenance pending replacement of the current secure alert tool, and retirement of the NERCnet – Interconnection Security Network and initiation of service using a new communication network developed, sponsored and managed by the Eastern Interconnection Data Sharing Network consortium. The Situation Awareness Department uses the following reliability-related tools to support its activities: Resource Adequacy (ACE Frequency) Tool; Inadvertent Interchange; Frequency Monitoring and Analysis Tool; Intelligent Alarms Tool; and Genscape (PowerIQ and PowerRT tools).

The ongoing and new major activities of the Situation Awareness department for 2017 include: ensuring that the ERO is aware of all BES events above a threshold of impact; enabling the sharing of information and data to facilitate wide area situational awareness; during crisis situations, facilitating the exchange of information among industry, Regions, and U.S. and Canadian governments; keeping the industry informed of emerging reliability threats and risks to the BES, including any expected actions; conducting the annual NERC Monitoring and Situational Awareness Conference and Human Performance Conference; and administering the NERC Alerts process as specified in §810 of the Rules of Procedure to issue Advisory (Level 1) Alerts on significant and emerging reliability and security related topics, and facilitate the tracking of actions specified in Recommendation (Level 2) and Essential Action (Level 3) Alerts.

The Event Analysis department performs assessments of the reliability and adequacy of the BES to identify potential issues of concern related to system, equipment, entity, and human performance that may indicate a need to develop remediation strategies, action plans, or data used to revise Reliability Standards or consider new Reliability Standards. Event Analysis conducts analyses to determine the causes of events, promptly assures tracking of corrective actions to prevent recurrence, and provides lessons learned to the industry. Event Analysis analyzes all reportable events for sequence of events, root cause, risks to reliability, and mitigation and ensures that the industry is well-informed of system events, emerging trends, risk analysis, lessons learned, and expected actions. Event Analysis conducts in-depth analyses of approximately 150 events per year on average. Additionally, Event Analysis identifies human error risks and precursor factors that allow human error to affect BES reliability, and educates industry regarding such risks, precursors, and related mitigation methods. Event analysis also supports compliance and standards training initiatives and trending and analysis to identify emerging reliability risks to the BES. Event Analysis works in collaboration with and supports the activities of other groups involved in human performance analysis including the NERC Operating Committee's Event Analysis Subcommittee, the WECC Human Performance Working Group, and others. Event Analysis also collaborates with industry groups including the NATF, NAGF, and trade associations.

The ongoing and new major activities for 2017 for the Event Analysis department include: (1) Working with Regional Entities to obtain and review information from registered entities on qualifying events and disturbances in order to advance awareness of events above a threshold level; facilitating analysis of root and contributing causes, risks to reliability, wide area assessments and remediation efforts; and disseminating information regarding events in a timely manner. (2) Ensuring that all

reportable events are analyzed for sequence of events, root cause, risk to reliability, and mitigation. (3) Continuing to refine risk-based methodologies to support better identification of reliability risks, including use of more sophisticated cause codes for analysis. (4) Ensuring consistency in reporting and analysis to support wide area assessments of significant reliability trends and risks. (5) Conducting training (webinars, workshops and conference support) to inform industry and the ERO of lessons learned, root cause analysis, trends, human performance, and cold weather preparedness and recommendations. (6) Developing reliability recommendations and alerts as needed. (7) Tracking industry accountability for critical reliability recommendations. (8) Ensuring that industry is well informed of system events, emerging trends, risk analysis, lessons learned, and expected actions. (9) Conducting major event analysis and reporting of major findings and recommendations that will improve reliability. (10) Advancing the quality and usefulness of reliability assessments and event analysis data. The Event Analysis department will also support several top priority reliability risk projects being led by the PA program.

The major activities of the RRM group satisfy the following criteria:

I.C.2: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as: (2) Monitoring, event analysis and investigations of Bulk Power System major events, off-normal occurrences and near-miss events?

II.E.2: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information to monitor and enforce compliance with Reliability Standards, including evaluating the effectiveness of current compliance monitoring and enforcement processes, the need for new or revised compliance monitoring and enforcement processes, and the need for new or different means of training and education on compliance with Reliability Standards, such as: (2) Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences, and near miss events?

II.F.3: Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as: (3) Disseminating, through workshops, webinars, Advisories, Recommendations, Essential Actions, and other publications; “lessons learned” information on compliance concerns and reliability risks obtained through compliance monitoring and enforcement activities; monitoring and investigation of Bulk Power System major events, off-normal occurrences and near miss events, and other Bulk Power System monitoring activities?

II.G: Is the activity necessary or appropriate for the development and provision of tools and services that are useful for the provision of adequate reliability, because they relate specifically to compliance with existing Reliability Standards and they proactively help avert Reliability Standard violations and Bulk Power System disturbances?

III.C: Is the activity necessary or appropriate for investigating, analyzing, evaluating, and disseminating information concerning, the causes of major events and off-normal occurrences, and/or providing coordination assistance, technical expertise and other assistance to users,

owners, and operators of the Bulk Power System in connection with Bulk Power System major events and off-normal occurrences, but not real-time operational control of the Bulk Power System?

III.D: Is the activity necessary or appropriate for awareness of circumstances on the Bulk Power System and to contribute to understanding risks to reliability?

III.F: Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for these major activities are §807, 808, 810 and 1001 and Appendix 8.)

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

VII. Electricity Information Sharing and Analysis Center 2017 Major Activities

The major activities of the Electricity Information Sharing and Analysis Center ("E-ISAC") are described at pages **Error! Bookmark not defined.**-63 of the 2017 Business Plan and Budget. The primary function of E-ISAC is to reduce cyber and physical risk to the Electricity Subsector across North America by providing unique insights, leadership and coordination, and to be the trusted, timely, actionable resource of grid risk information and analysis to enhance electric reliability. The E-ISAC facilitates sector coordination regarding physical security and cybersecurity events affecting the BES. E-ISAC analytic personnel maintain a detailed understanding of emerging vulnerabilities and threats within the broad industrial control systems community and the more focused BES community. E-ISAC manages and executes NERC's responsibilities in the Cybersecurity Risk Information Sharing Program ("CRISP") and acts as the program manager for CRISP. The purpose of CRISP is to facilitate the sharing of cyber threat information and to develop situation awareness tools that enhance the electricity sector's ability to identify, prioritize, and coordinate protection of its critical infrastructure. Finally, ES-ISAC also supports an annual grid security conference and a biennial Grid Security Exercise.

The major activities of the ES-ISAC satisfy the following criteria:

I.C.1: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as: (1) Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks? (2) Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences and near-miss events?

III.D: Is the activity necessary or appropriate for awareness of circumstances on the Bulk Power System and to contribute to understanding risks to reliability.

III.E: Is the activity necessary or appropriate for gathering, analyzing and sharing with and among industry and government participants, information regarding the physical or cyber security of the Bulk Power System.

III.F: Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for these major activities are §810 and 1003.)

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

VIII. Training, Education, and Operator Certification Program 2017 Major Activities

The major activities of the Training, Education, and Operator Certification Program are described at pages 65-68 of the 2017 Business Plan and Budget. The major activities of this program include oversight and coordination of the delivery of training programs to NERC and Regional Entity staff; as well as training and education for industry participants on the requirements of Reliability Standards, the Reliability Standards development process, and the compliance monitoring and enforcement process. The Training and Education Program supports the ERO's responsibilities to develop, adopt, and obtain approval of Reliability Standards and to monitor, enforce and achieve compliance with the mandatory standards. The Training and Education Program also supports NERC's System Operator Certification Program, which ensure that personnel operating the BES have the skills, training and qualifications needed to operate the BES reliably. This Program maintains the credentials required to work in system control centers across North America for over 6,000 system operators. The Training and Education Program prepares operators for complying with requirements of Reliability Standards and appropriately operating the BES during normal and emergency operations. Education and training activities include the following subject matter: risk-based compliance monitoring and enforcement; standards and compliance; registration and certification; event analysis, cause analysis, and lessons learned; reliability assessment and system analysis; continuing education for system operators; and new system operator certification examinations for the Reliability Coordinator, Transmission Operator, Balancing and Interchange Operator, and Balancing, Interchange and Transmission Operator credentials.

The major activities of the Training, Education, and Operator Certification Program for 2017 include providing and expanding training and education for ERO personnel and industry in the following areas: Reliability Standards compliance, emerging cyber-related issues; auditor skills and consistent audit and investigation techniques and standards compliance reviews, including risk-based compliance monitoring and enforcement and other improvements in compliance and enforcement practices; development and implementation of clear and technically sound Reliability Standards; lessons learned and trends from events, and identified themes from trending and common cause analysis; effective root,

apparent and common cause analysis methods; quality improvement of registered entity self-reporting and self-certification; entity registration processes, issues and alternatives; human performance fundamentals; and developing and incorporating a systematic approach to ongoing training. The Training, Education, and Operator Certification Program will continue to work with industry stakeholders and the System Operator Certification exam vendor to create certification exams that will promote reliability of the BPS. Further, the Continuing Education (CE) program will evaluate and revise the current program criteria as reflected in the CE program manual, taking into account the growth and maturation of industry training programs as well as ongoing research on adult learning to ensure the CE program continues to foster improvements in training and promotes quality in training programs.

The major activities of the Training, Education, and Operator Certification Program satisfy the following criteria:

I.D: Is the activity necessary or appropriate for the provision of training and education concerning Reliability Standards development processes, procedures and topics for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel?

II.C: Is the activity necessary or appropriate for the Certification of system operating personnel as qualified to carry out the duties and responsibilities of their positions in accordance with the Requirements of applicable Reliability Standards?

II.F: Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as: (1) Requirements of Reliability Standards, including how to comply and how to demonstrate compliance? This includes development of guidance and interpretation documents. (2) Compliance monitoring and enforcement processes, including how to conduct them, how to participate in them, and the expectations for the processes? This includes development of guidance documents. (3) Disseminating, through workshops, webinars, Advisories/Recommendations/Essential Actions, and other publications, "lessons learned" information on compliance concerns and reliability risks obtained through compliance monitoring and enforcement activities, monitoring and investigation of Bulk Power System major events, off-normal occurrences and near miss events, and other Bulk Power System monitoring activities. (4) Registered Entity internal processes for compliance with Reliability Standards, such as development, implementation and maintenance of internal reliability compliance programs?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provision for these major activities are §600 and 900.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

IX. Administrative Services 2017 Major Activities

NERC's Administrative Services Departments are Technical Committees and Member Forums (for which no funding for activities is budgeted for 2017), General and Administrative, Legal and Regulatory, Information Technology ("IT"), Human Resources, and Finance and Accounting. The major activities of these departments are described at pages 69-79 of the 2017 Business Plan and Budget.

General and Administrative includes the administration and general management of the organization, the Chief Executive Officer and Chief Reliability Officer, Board of Trustees fees and expenses, communications, external affairs and government relations, office rent, and support of the activities of the NERC Member Representatives Committee and the Regional Entity Management Group.

Legal and Regulatory provides legal support to the organization, including to management, and the Reliability Standards, Compliance Analysis and Certification and Registration, Reliability Risk Management, and RASA Programs, as well as general corporate legal support in areas including antitrust, corporate, commercial, insurance, contracts, employment, real estate, copyright, tax, and other areas.

IT supports NERC's computing, Internet, database and electronic data storage and maintenance, and telecommunications needs, programs, applications and infrastructure, including management of the development and implementation of new software applications and infrastructure. The capital expenditure projects managed by IT represent capital expenditures in hardware, software and associated tools to securely gather, store, analyze and maintain data across the ERO Enterprise to support the ERO's operations, as well as necessary acquisition and replacement of computers, servers and related devices. IT's 2017 activities are focused on NERC infrastructure and support; improving, enhancing, or replacing existing functionalities; ERO Enterprise infrastructure and support; and ERO Enterprise new functionalities.

Human Resources manages all of NERC's human resources functions, including staffing, benefits administration, employee relations, performance and compensation management, succession planning, and training and development. Human Resources also obtains compensation studies, effectiveness studies, and other compensation consulting services when needed.

Finance and Accounting manages all finance and accounting functions of NERC, including employee payroll, 401(k), 457(b) and 457(f) plans, travel and expense reporting, monthly financial reporting, sales and use tax, meetings and events planning and services, insurance, internal audit, facilities management, development of the annual business plan and budget, and the ERO risk management framework.

The major activities of NERC's Administrative Services Departments satisfy the following criteria:

I.A: Is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure (ROP)?

II.A: Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

II.D: Is the activity necessary or appropriate for conducting, participating in or overseeing compliance monitoring and enforcement activities pursuant to the NERC ROP and (through the Regional Entities) the Commission-approved delegation agreements?

III.C: Is the activity necessary or appropriate for investigating, analyzing, evaluating, and disseminating information concerning, the causes of major events and off-normal occurrences, and/or providing coordination assistance, technical expertise and other assistance to users, owners, and operators of the Bulk Power System in connection with Bulk Power System major events and off-normal occurrences, but not real-time operational control of the Bulk Power System?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provision for the major activities of Finance and Accounting is §1100.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and the applicable provisions of Commission orders.

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

XI: Is the activity a governance or administrative/overhead function, activity or service necessary or appropriate for the activities encompassed by the other criteria and, in general, necessary and appropriate to operate a functioning organization?

NERC WRITTEN CRITERIA FOR DETERMINING WHETHER AN ACTIVITY IS ELIGIBLE TO BE FUNDED UNDER SECTION 215 OF THE FEDERAL POWER ACT

For purposes of internal management approval of a proposed new activity or group of related activities ("major activity"), the proposed activity or major activity must be shown to fall within at least one of the criteria listed below. When sub-criteria are listed below a roman numeral numbered major criterion, the proposed activity should be a positive answer to at least one of the sub-criteria. Conversely, an activity that falls under a sub-criterion should pertain to the subject matter of the major criterion.

NERC's annual business plan and budget will describe how each major activity falls within one or more of the criteria listed below. If the major activity is substantially the same as a major activity that was shown to fall within the criteria in a previous year's business plan and budget, the current year's business plan and budget can refer to the prior year business plan and budget.

A determination that an activity falls within FPA §215 does not necessarily mean that NERC will propose or undertake such activity. The determination of whether an activity falling under FPA §215 should or will be undertaken in a given budget year will be addressed in the context of the applicable business plan and budget and will include opportunities for stakeholder input.

The criteria listed below are not necessarily each distinct from the others. An activity or major activity may fall within more than one of the criteria listed below.

I. Is the activity necessary or appropriate for the development of Reliability Standards?

   A. Is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure (ROP)?

   B. Is the activity necessary or appropriate for providing guidance and assistance to Regional Entities in carrying out Regional Reliability Standards development activities?

   C. Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as:

      1. Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System[46] based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

      2. Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences and near miss events?

   D. Is the activity necessary or appropriate for the provision of training and education concerning Reliability Standards development processes, procedures and topics for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel?

II. Is the activity necessary or appropriate for the monitoring and enforcement of compliance with Reliability Standards?

   A. Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with

[46] This document uses the term "Bulk Power System" because that is the term defined and used in FPA §215. NERC recognizes that a different term, "Bulk Electric System," is used to define the current reach of reliability standards. Reliability Standards.

Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

B. Is the activity necessary or appropriate for the Certification of Reliability Coordinators, Transmission Operators and Balancing Authorities as having the requisite personnel, qualifications and facilities and equipment needed to perform these reliability functions in accordance with the applicable Requirements of Reliability Standards?

C. Is the activity necessary or appropriate for the Certification of system operating personnel as qualified to carry out the duties and responsibilities of their positions in accordance with the Requirements of applicable Reliability Standards?[47]

D. Is the activity necessary or appropriate for conducting, participating in or overseeing compliance monitoring and enforcement activities pursuant to the NERC ROP and (through the Regional Entities) the Commission-approved delegation agreements?

E. Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information to monitor and enforce compliance with Reliability Standards, including evaluating the effectiveness of current compliance monitoring and enforcement processes, the need for new or revised compliance monitoring and enforcement processes, and the need for new or different means of training and education on compliance with Reliability Standards, such as:

1. Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

2. Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences, and near miss events?

F. Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as:

1. Requirements of Reliability Standards, including how to comply and how to demonstrate compliance? This includes development of guidance and interpretation documents.

2. Compliance monitoring and enforcement processes, including how to conduct them, how to participate in them, and the expectations for the processes? This includes development of guidance documents.

3. Disseminating, through workshops, webinars, Advisories, Recommendations, Essential Actions, and other publications; "lessons learned" information on compliance concerns and reliability risks obtained through compliance monitoring and enforcement activities; monitoring and investigation of Bulk Power System major events, off-normal occurrences and near miss events, and other Bulk Power System monitoring activities?

[47] Although certification of system operating personnel is an activity falling within the scope of, and eligible to be funded pursuant to, FPA §215, NERC strives to fully fund the costs of this activity through fees charged to participants.

4. Registered Entity internal processes for compliance with Reliability Standards, such as development, implementation and maintenance of internal reliability compliance programs?

G. Is the activity necessary or appropriate for the development and provision of tools and services that are useful for the provision of adequate reliability, because they relate specifically to compliance with existing Reliability Standards and they proactively help avert Reliability Standard violations and Bulk Power System disturbances?

III. Is the activity necessary or appropriate for conducting and disseminating periodic assessments of the reliability of the Bulk Power System or monitoring the reliability of the Bulk Power System?

A. Is the activity necessary or appropriate for the preparation or dissemination of long-term, seasonal, and special assessments of the reliability and adequacy of the Bulk Power System?

B. Is the activity necessary or appropriate for measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

C. Is the activity necessary or appropriate for investigating, analyzing, evaluating, and disseminating information concerning, the causes of major events and off-normal occurrences, and/or providing coordination assistance, technical expertise and other assistance to users, owners, and operators of the Bulk Power System in connection with Bulk Power System major events and off-normal occurrences, but not real-time operational control of the Bulk Power System?

D. Is the activity necessary or appropriate for awareness of circumstances on the Bulk Power System and to contribute to understanding risks to reliability?

E. Is the activity necessary or appropriate for gathering, analyzing and sharing with and among industry and government participants, information regarding the physical or cyber security of the Bulk Power System?

F. Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

G. Is the activity necessary or appropriate for data collection and analysis of information regarding Bulk Power System reliability matters mandated by the Commission?

IV. Is the activity one that was required or directed by a Commission order issued pursuant to FPA §215? Justification of an activity as a FPA §215 activity based on this category must reference the particular Commission order and directive.

V. Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)?

VI. Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

VII. Is the activity necessary or appropriate to maintain NERC's certification as the Electric Reliability Organization? This Criterion includes conducting periodic assessments of NERC's and the Regional Entities' performance as the Electric Reliability Organization as required by 18 C.F.R. §39.3(c).

VIII. Does the activity respond to or is it necessary or appropriate for audits of NERC and the Regional Entities conducted by the Commission?

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

X. Is the activity necessary or appropriate for the analysis and evaluation of activities encompassed by one or more of the other criteria for the purpose of identifying means of performing the activities more effectively and efficiently?

XI. Is the activity a governance or administrative/overhead function, activity or service necessary or appropriate for the activities encompassed by the other criteria and, in general, necessary and appropriate to operate a functioning organization? (Should NERC perform any non-FPA §215 activities, the costs of governance and administrative/overhead functions must be appropriately allocated.)
NERC's current governance and administrative/overhead functions are carried out in the following program areas:

A. Technical Committees and Members' Forum Programs

B. General and administrative (includes, but is not limited to, executive, board of trustees, communications, government affairs, and facilities and related services).

C. Legal and Regulatory.

D. Information Technology

E. Human Resources

F. Accounting and Finance.

The following matters are excluded from the scope of FPA §215 activities. While a list of non-FPA §215 activities would be infinite, the following excluded matters are listed here because they are expressly referred to in FPA §215, the Commission's ERO regulations and/or a Commission order issued pursuant to FPA §215:

A. Developing or enforcing requirements to enlarge Bulk Power System facilities, or to construct new transmission capacity or generation capacity, or requirements for adequacy or safety of electric facilities or services.

B. Activities entailing Real-time operational control of the Bulk Power System.

C. Activities pertaining to facilities used in the local distribution of electricity.

Exhibit C – Contractor and Consulting Costs

Program	Consultants & Contracts	2016 BUDGET	2017 BUDGET	2017 vs 2016 Budget
Compliance Assurance	Reliability Assurance Initiative	200,000	50,000	(150,000)
	Compliance Assurance	**200,000**	**50,000**	**(150,000)**
Event Analysis	Reliability Assurance Project Support	56,000	-	(56,000)
	Event Analysis	**56,000**	**-**	**(56,000)**
Compliance Investigation, Registration and Certification	Risk-based Registration Phase 2 - Consulting Support	50,000	-	(50,000)
	Compliance Investigation, Registration and Certification	**50,000**	**-**	**(50,000)**
Reliability Assessments and System Analysis	Reliability affects of GMD	100,000	100,000	-
	Reliability consulting support	475,000	425,000	(50,000)
	Reliability Assessments and System Analysis	**575,000**	**525,000**	**(50,000)**
Performance Analysis	GADS/TADS/DADS/SED	509,039	528,082	19,044
	Performance Analysis	**509,039**	**528,082**	**19,044**
Situation Awareness	Reliability Tools	576,300	619,150	42,850
	Secure Alerting System	141,000	96,000	(45,000)
	SAFNR - Phase II	438,200	505,700	67,500
	Communication network (NERCnet replacement)	55,975	75,000	19,025
	Situation Awareness	**1,211,475**	**1,295,850**	**84,375**
E-ISAC	**GridEx Support**	-	250,000	250,000
	Program-Level Capabilities	366,500	353,000	(13,500)
	Software & Services	113,285	113,285	-
	Events & Outreach	50,550	50,550	-
	CRISP	5,888,594	5,888,594	-
	E-ISAC and CRISP	**6,636,929**	**6,788,429**	**151,500**
System Operator Certification	System Operator Testing Expenses	59,400	62,000	2,600
	System Operator Examination Development	69,000	70,000	1,000
	Database Development	24,000	-	(24,000)
	Database Maintenance	25,200	37,800	12,600
	SOCCED Database Improvement Project (funded from Working Capital generated from fees in excess of expenses)	150,000	50,000	(100,000)
	System Operator Certification	**327,600**	**219,800**	**(107,800)**
Training and Education	Continuing Education Program	133,200	145,800	12,600
	Web-based course hosting (Learning Management System)	55,000	55,000	-
	Enhanced Platform	-	-	-
	Course development and Support - External Training	125,000	125,000	-
	NERC Staff Technical Training	35,000	35,000	-
	Continuing Education, Training & Education	**348,200**	**360,800**	**12,600**
General & Administrative	Communications support	15,000	15,000	-
	0	-	-	-
	ERO Effectiveness Survey	80,000	-	(80,000)
	General & Administrative	**95,000**	**15,000**	**(80,000)**
IT	ERO Development & Support	988,671	1,161,787	173,116
	ERO Data Analysis	100,000	200,000	100,000
	Applications Enhancements, Consulting and Help Desk Support	1,006,000	851,000	(155,000)
	Information Technology	**2,094,671**	**2,312,787**	**218,116**
HR	Training and Development	325,000	350,000	25,000
	Compensation Consulting	100,000	100,000	-
	Employee, industry and Board Surveys	50,000	50,000	-
	HR Consulting Services	75,000	75,000	-
	Human Resources	**550,000**	**575,000**	**25,000**
Finance	Internal Controls and Outside Auditor Consulting Support	200,000	300,000	100,000
	Finance and Accounting Support	97,000	97,000	-
	Finance and Accounting	**297,000**	**457,000**	**160,000**
	TOTAL CONSULTANTS AND CONTRACTS	**12,950,914**	**13,127,749**	**176,835**

Exhibit D – Capital Financing

The company successfully closed on its capital financing program on January 10, 2014. The interest rate is floating and equal to LIBOR plus 275 basis points, which yielded a rate of 2.91% at closing.[48] The total size of the non-revolving credit facility is $7.5M, with the total authorized borrowings each year limited to the amount approved by the Board of Trustees and FERC in that year's business plan and budget for IT hardware and the costs of developing software applications. Consistent with the terms of the loan documentation and its Board and FERC-approved 2014 budget, the company made an initial draw of $1.265M at the end of January 2014 related to 2013 expenditures. The company recorded new capital investments of approximately $1.65M in 2013 related to the development of software applications and IT hardware,[49] a portion of which was financed with the proceeds from this initial draw. This borrowing is amortized over three years, commencing January 31, 2014, and can be prepaid without penalty. A balance of $1.416M was available for draw during 2014, which was also consistent with NERC's 2014 approved budget. However, the company had sufficient funds available to pay for budgeted capital improvements without having to draw on this credit facility. A balance of $1.9M was available for draw during 2015, consistent with NERC's 2015 approved budget. New capital investments of $1.85 were financed with draws late in 2015 and early 2016. These new borrowings are also being amortized over three years, beginning January, 2016 and April, 2016. The company is in discussions with the lender about renewing this facility going into 2017, with terms and conditions of the renewed facility similar to those in the current agreement.

As further discussed in the Introduction and Executive Summary and in Section A, General and Administrative and set forth in the table below, NERC has a 2017 proposed capital budget of approximately $4.4M, $1.45M of which it is proposing to finance.

NERC CAPITAL BUDGET	2016	2017
ERO Application Development	$ 1,500,000	$ 700,000
E-ISAC Portal Development		1,000,000
Document Management	465,000	335,000
Hardware (Storage, servers, laptops)	955,000	991,000
Other Equipment	535,000	885,000
Disaster Recovery	200,000	150,000
NERC Software licenses	256,000	311,000
Total Capital Budget	**$ 3,911,000**	**$ 4,372,000**

The table below sets forth the projected principal and interest repayment schedule for the amounts financed to date and the additional planned $1.45M in capital financing. This projection assumes an average interest rate of 3.5% over the term of the financing, which is consistent with the 2014 budget. Management is recommending that 3.5% continue to be used given the potential for interest rate increases during 2016. The actual interest rate and interest rate expense will be reflected in the quarterly budget to actual variance reports the company posts on its website, reviews in open session with the NERC Finance and Audit Committee, and files with FERC. Any variations in interest expense will be captured and reported as a contribution to operating reserves, the expenditures of which are subject to the terms of the company's Working Capital and Operating Reserve Policy.

[48] The interest rate at closing was lower than projected for purposes of the 2014 budget. As detailed in the company's approved *2014 Business Plan and Budget*, any difference between actual and budgeted interest expense for draws under the credit facility becomes an addition to the company's Unforeseen Contingency Operating Reserve balance.

[49] This capital investment amount is exclusive of approximately $640k in expenses which were incurred in 2013 in the development of the Events Information Data System application and expensed rather than capitalized, as further discussed in the company's Q1 2014 budget variance report presented to the NERC Finance and Audit Committee.

	YEAR-END OUTSTANDING DEBT BALANCE					
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
2013 Expenditure / Closed 2014	$ 878,472	$ 456,806	$ 35,139	$ -	$ -	
2015 Budgeted	-	-	1,234,547	617,274	-	
2016 Budgeted	-	-	1,500,000	666,667	333,333	
2017 Projected	-	-	-	1,450,000	966,667	483,333
2018 Projected	-	-	-	-	1,800,000	1,200,000
Total Outstanding Balance	$ 878,472	$ 456,806	$2,769,686	$2,733,940	$3,100,000	$1,683,333

	ANNUAL PAYMENTS FOR DEBT SERVICE					
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
2013 Expenditure / Closed 2014	$ 386,528	$ 421,667	$ 421,667	$ 35,139	$ -	
2015 Budgeted	-	-	617,274	617,274	617,274	
2016 Budgeted	-	-	-	333,333	333,333	333,333
2017 Projected	-	-	-	-	483,333	483,333
2018 Projected	-	-	-	-	-	600,000
Interest Expense	29,367	24,826	56,529	56,725	61,170	72,203
Total Principal and Interest Costs	$ 415,895	$ 446,493	$1,095,469	$1,042,471	$1,495,110	$1,488,869

Exhibit E – Working Capital and Operating Reserve Amounts

In February 2015, the NERC Board approved an amendment to the Company's Working Capital and Operating Reserve Policy. A number of changes were made to the policy, including:

- Clarifying the definition of working capital to represent funding needed for cash flow purposes due to the timing of the receipt of funds and the payment of expenses.
- Creating four separate categories of operating reserves:
    1. A new subcategory of reserves entitled **Future Obligation Reserve** for funds that are being held to satisfy obligations that will be settled in a future year. Examples include leases, certain contracts, and credit agreements. These reserves were previously within the definition of working capital and are more accurately classified as a form of operating reserve.
    2. Continuation of a separate category of reserves for the Operator Certification Program called the **Operator Certification Reserve**.
    3. Elimination of the Known and Unforeseen Contingency categories of operating reserves and creating a single category of contingency reserves called the **Operating Contingency Reserve**.
    4. Creation of a separate category of reserves for CRISP called the **CRISP Reserve**.

Working Capital

Based on its 2016 cash flow projection and taking into account the historic manner in which NERC's assessments have been billed and paid, NERC does not anticipate needing access to working capital in 2017 to meet monthly cash flow needs. While individual reserve categories are increasing and decreasing based on operating needs and uses, the budget in total does not reflect additional net funding for reserves. In the unlikely event NERC experiences a temporary cash flow shortage, it has the ability to either request authorization from the Finance and Audit Committee and Board of Trustees to temporarily access operating contingency reserve funds, or draw on its $4M line of credit, as long as NERC is in compliance with the covenants under its bank credit agreement.

Operating Reserves

Total operating reserves are projected to be $5.5M among all four categories. The Future Obligation Reserve is budgeted to be $2.6M and is primarily funds held to offset future liabilities under lease agreements for the Atlanta and Washington, DC, offices. System Operator Certification Reserves are budgeted at $714k and the Operating Contingency Reserve is budgeted for $2.2M. The CRISP Reserve (budgeted at $500k) is held pursuant to the terms of the Master Services Agreement between NERC and participating utilities, which calls for a separate third-party funded reserve established to fund certain contingencies in connection with CRISP.

In addition to the foregoing reserves, the amended policy also provides for the creation of an **Assessment Stabilization Reserve.** The goal of the Assessment Stabilization Reserve is to mitigate assessment volatility and have changes in annual assessments track, within a reasonable band, changes in the company's total annual budget, with the total budget reflecting prudent fiscal discipline and good stewardship of resources. Assessment stabilization funds will be used when available to help stabilize assessments and mitigate year-to-year swings in assessments. Those swings primarily result from the application of penalty funds, but could also result from other factors like surplus funds available from a prior period, the need to replenish the Operating Contingency Reserve, or significant but relatively short-term operating or capital spending needs. Pending NERC Board approval of the release of restricted penalties into this reserve, the balance on January 1, 2017 will be $2.7M and has, to date, been funded entirely by penalties. NERC is proposing to use $1.1M of the balance to offset 2017 U.S. assessments. An additional penalty is expected in May 2017 for $500,000. This penalty results from a settlement reached through WECC related to the September 2011 blackout.

E-ISAC
ELECTRICITY INFORMATION SHARING AND ANALYSIS CENTER

Exhibit F - From Portal to Platform

A Capabilities Case for Improving Information Sharing in the Electricity Sector

RESILIENCY | RELIABILITY | SECURITY






Why Information Sharing Matters

- Cyber and physical threats do not come from machines
  - They originate in the minds of human adversaries
  - Cyberspace is just a tool for the adversary
  - So are explosives, weapons, truck bombs, bolt cutters and social engineering
- Threat actors typically don't work alone
  - Strategic "existential" threats (the ones we should worry about) are typified by large, well connected organizations
  - These groups routinely share, collaborate, and analyze situations freely, using every tool available including the Internet and technology
- Our challenge is to be better at sharing, collaborating, and analyzing than our adversaries
  - We need better tools than those they have

Membership Involvement

- ESCC Strategic Review (July 2015) called for continued improvement to the portal
  - Recommended the use of STIX/TAXII standards
  - Recommended the exploration of ways to automate information sharing and analysis
- Updated portal launched in September 2015
- GridEx III Simulation Deck portal used in November 2015 offered several new ideas about grid security visualization
- MEC's OTT working group developed a comprehensive list of portal improvement recommendations

Portal to Platform Timeline

- 2016:
  - Fix existing portal bugs and issues identified by the E-ISAC and members
  - Build incremental improvements to meet short-term recommendations
  - Conduct scoping/discovery effort for transition to platform
  - Validate requirements with membership
  - Launch new “look and feel” for existing portal
- 2017:
  - Install new hardware
  - Launch new platform
  - Build incremental improvements to meet long-term requirements
  - Ongoing membership feedback

Expected Benefits

- Dramatic improvement to information sharing
  - Human to human via text, discussion, document, photo, etc. sharing
  - Machine to machine via built in STIX/TAXII compatibility
- Rapid response to emerging critical situations
  - Situational awareness of physical and cyber events
  - Coordination within and external to the Electricity Sector
- Extendable as new technologies emerge
  - Easy integration with mobile technologies
  - Designed to be modular and adaptable to future capability requirements
- Increased trust in the E-ISAC
  - Will result in increased sharing and collaboration

Portal vs Platform

- Existing portal characteristics
  - Designed for a specific audience with a specific purpose
  - Static content with infrequent changes
  - No user control over look/feel of layout
  - Not designed for high levels of interaction
  - Limited search capability
- Proposed platform characteristics
  - Designed for a wide audience with different needs
  - Highly customizable by users
  - Extendable to accommodate new technologies
  - Visual and graphical orientation (vs text-based)
  - Robust search, filtering, and native language queries of datasets
  - Server-side computation and analytics

Project Management

- Total proposed 2017 budget of $1 million
- Two parallel projects
  - Near-term quick fixes and user interface improvements
  - Long-term movement to a platform with significant changes
- Project implementation managed by NERC CTO and the ERO IT PMO
- Disciplined approach used to successfully manage and implement other recent IT projects
- Ongoing MEC engagement
- Scope will be managed within approved budget

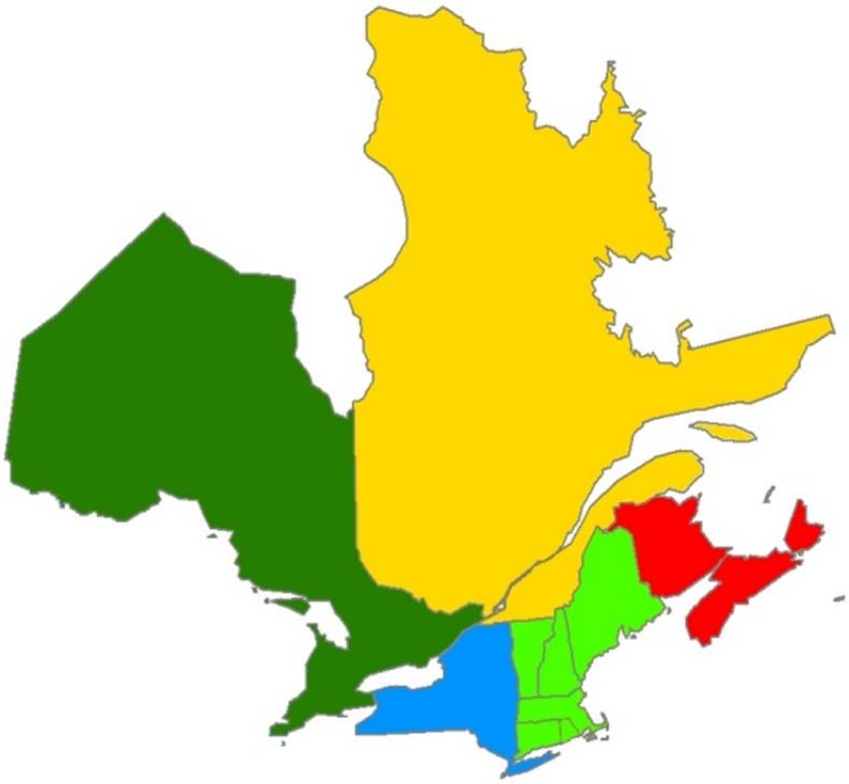
MEC Feedback

- MEC briefed at June 15, 2016 face-to-face meeting
- Bill Spence (Chairman, President and CEO, PPL Corporation, Inc. and Chair, E-ISAC Member Executive Committee) briefed EEI's Executive Committee on June 14, 2016 and provided positive feedback
- The MEC provided NERC with written comments in support of the proposed funding on or before June 30, 2016.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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Northeast Power Coordinating Council, Inc. (NPCC)

2017 Business Plan and Budget



Draft 1
Submitted to NERC
April 28, 2016

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Introduction

Total NPCC Resources (in whole dollars)	2016 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	$15,121,054			
Criteria Services Division Expenses	$1,036,896			
Total Expenses	**$16,157,950**			
Regional Entity Division Inc(Dec) in Fixed Assets	**$26,000**			
Criteria Services Division Inc(Dec) in Fixed Assets	**($10,000)**			
Total Inc(Dec) in Fixed Assets	**$16,000**			
Regional Entity Division Working Capital Requirement**	**($663,357)**			
Criteria Services Division Working Capital Requirement***	**($85,665)**			
Total Working Capital Requirement	**($749,023)**			
Total Regional Entity Division Funding Requirement	$14,483,697			
Total Criteria Services Division Funding Requirement	$941,230			
Total Funding Requirement	**$15,424,927**			
Regional Entity Division Assessments	**$14,419,697**	$XXX,XXX	$XXX,XXX	
Regional Entity Division Assessments Percentage	**100.0%**	XX.X%	XX.X%	
Criteria Services Division Membership Fees	**$941,230**	$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 in Section B.
*** Refer to the Reserve Analysis on page in Section C.

2017 Overview of Total NPCC Resource Requirements

Due to the international nature of NPCC, the total resource requirements including both Regional Entity division and Criteria Services division are identified above. The individual divisional explanations are contained in subsequent sections.

NPCC proposes to decrease its total budget and assessments by -0.3% comprising a Regional Entity increase of 0.5% and a Criteria Services division decrease of -11.3%. The proposed 2017 funding requirements will be satisfied by a Regional Entity division assessment of $14,419,697 and Criteria Services division fees of $941,230, for a total of $15,360,927. This is an overall decrease of -0.3% compared to the 2016 total assessments and fees of $15,409,738. 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.

In this 2017 business plan, NPCC has included activities consistent with NERC initiatives including the enhancement of reliability assessments, risk-based registration, risk-based compliance monitoring and enforcement, expanded training for compliance auditing, and increased situation awareness.

It is imperative that NPCC maintain its ability to carry out delegated authorities and responsibilities. NPCC has a flat 2017 targeted staffing level of 39 power industry professionals and support personnel. Details of the 2017 business plans and budget for each program area are included in Section A for the Regional Entity division. The 2017 Regional Entity division schedules are shown in Section B. Section C details the 2017 criteria services division business plan and budget.

Membership and Governance

NPCC monitors approximately 212 registered entities and some 426 functions in the Region for compliance with mandatory Reliability Standards. NPCC currently has approximately 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* establishes 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 an 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. A 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 Hydro-Québec companies, including Hydro-Québec TransÉnergie, Hydro-Québec Distribution and Hydro-Québec Production are subject to voluntary compliance monitoring and enforcement, including comprehensive audits by NPCC.

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.

The Hydro-Québec companies, including Hydro-Québec TransÉnergie and Hydro-Québec Production have been subject to voluntarily compliance monitoring and enforcement, including comprehensive audits by NPCC. NPCC plans to continue to these voluntary compliance monitoring and enforcement activities for any standards that have not yet been declared in effect by the Régie de l'énergie. Additionally, NPCC has and continues to proceed with its 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

The New Brunswick Energy and Utilities Board ("NBEUB") and NPCC entered into an Agreement dated October 1, 2013, whereby NPCC provides services for the NBEUB. The NBEUB is a not-for-profit corporation which was established on October 1, 2004 under the Electricity Act (NB) and charged with developing and administering the wholesale electricity market and maintaining reliability of the integrated power system in New Brunswick.

Effective 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 October 1, 2013 Agreement between NPCC and the NBEUB is intended to be the preliminary step with respect to the implementation of the NB Electricity Act.

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 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 the NBPC 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 requires NPCC to identify entities that must register with the NBEUB in the New Brunswick specific registry. Additionally, NPCC is required to 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. 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.

2017 Key Assumptions and 2017 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 2016 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 2017 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.

2017 Overview of Regional Entity Division Cost Impacts

The proposed Regional Entity division assessment of $14,419,697 to support the budget is an increase of 0.5% compared to the 2016 assessment of $14,349,196.

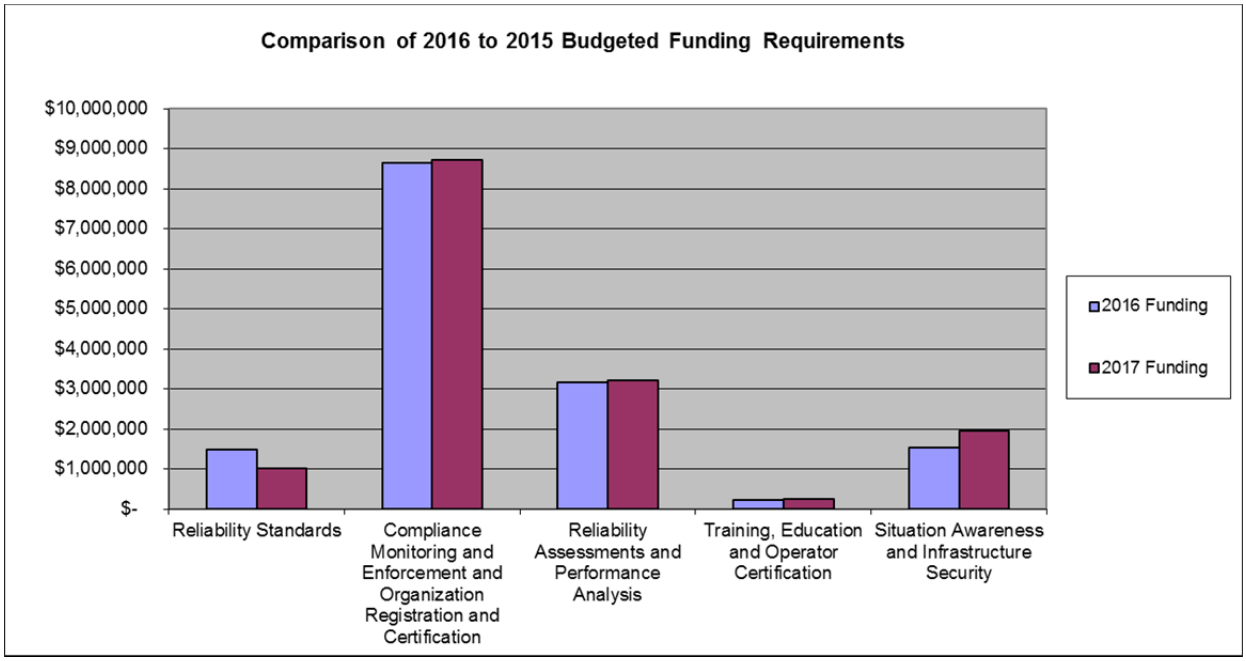
2016 Projections

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. 2016 Projections reflect expectations based on the first quarter variance report. It is anticipated that projections could change throughout 2016 and would be reflected in each subsequent quarter's variance report.

Summary by Program

Program	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Reliability Standards	$ 1,487,419	$ 1,487,419	$ 1,022,328	$ (465,091)	-31.3%
Compliance Monitoring and Enforcement and Organization Registration and Certification	$ 8,650,196	$ 8,650,196	$ 8,726,049	$ 75,853	0.9%
Reliability Assessments and Performance Analysis	$ 3,171,574	$ 3,171,574	$ 3,206,966	$ 35,392	1.1%
Training, Education and Operator Certification	$ 219,956	$ 219,956	$ 248,658	$ 28,702	13.0%
Situation Awareness and Infrastructure Security	$ 1,543,852	$ 1,543,852	$ 1,943,053	$ 399,201	25.9%
Total	$ 15,072,998	$ 15,072,998	$ 15,147,054	$ 74,057	0.5%

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 2016	Projection 2016	Direct FTEs 2017 Budget	Shared FTEs[1] 2017 Budget	Total FTEs 2017 Budget	Change from 2016 Budget
REGIONAL ENTITY DIVISION						
Operational Programs						
Reliability Standards	2.93	2.93	1.00	0.93	1.93	-1.00
Compliance Monitoring and Enforcement and Organization Registration and Certification	16.00	16.00	17.00	0.00	17.00	1.00
Training, Education, and Operator Certification	0.10	0.10	0.10	0.00	0.10	0.00
Reliability Assessment and Performance Analysis	5.83	5.83	4.90	0.93	5.83	0.00
Situation Awareness and Infrastructure Security	3.00	3.00	4.00	0.00	4.00	1.00
Total FTEs Operational Programs	**27.86**	**27.86**	**27.00**	**1.86**	**28.86**	**1.00**
Administrative Programs						
Technical Committees and Member Forums	0.50	0.50	0.50	0.00	0.50	0.00
General and Administrative	2.50	2.50	2.50	0.00	2.50	0.00
Information Technology	3.00	3.00	2.00	0.00	2.00	-1.00
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	**9.00**	**9.00**	**8.00**	**0.00**	**8.00**	**-1.00**
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.

2016 Budget and Projection and 2017 Budget Comparisons

Statement of Activities and Capital Expenditures
2016 Budget & Projection, and 2017 Budget

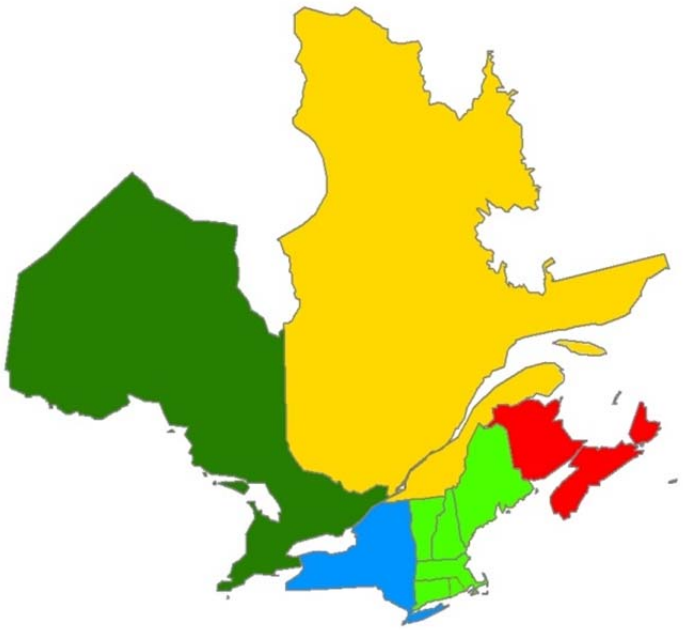
REGIONAL ENTITY DIVISION

	2016 Budget	2016 Projection	Variance[2] 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 14,349,196	$ 14,349,196	$ -	$ 14,419,697	$ 70,501
Penalty Sanctions[1]	67,000	67,000	-	-	(67,000)
Total ERO Funding	**$ 14,416,196**	**$ 14,416,196**	**$ -**	**$ 14,419,697**	**$ 3,501**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	64,000	64,000	-	64,000	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 14,480,196**	**$ 14,480,196**	**$ -**	**$ 14,483,697**	**$ 3,501**
Expenses					
Personnel Expenses					
Salaries	$ 6,561,470	$ 6,561,470	$ -	$ 6,758,926	$ 197,456
Payroll Taxes	399,057	399,057	-	404,319	5,262
Benefits	1,364,799	1,364,799	-	1,415,603	50,804
Retirement Costs	833,118	833,118	-	847,223	14,105
Total Personnel Expenses	**$ 9,158,445**	**$ 9,158,445**	**$ -**	**$ 9,426,071**	**$ 267,627**
Meeting Expenses					
Meetings	$ 394,000	$ 394,000	$ -	$ 377,100	$ (16,900)
Travel	907,100	907,100	-	855,232	(51,868)
Conference Calls	47,000	47,000	-	37,000	(10,000)
Total Meeting Expenses	**$ 1,348,100**	**$ 1,348,100**	**$ -**	**$ 1,269,332**	**$ (78,768)**
Operating Expenses					
Consultants & Contracts	$ 2,223,500	$ 2,223,500	$ -	$ 2,009,000	$ (214,500)
Office Rent	802,500	802,500	-	809,700	7,200
Office Costs	639,500	639,500	-	679,100	39,600
Professional Services	1,011,000	1,011,000	-	1,041,000	30,000
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	41,000	41,000	-	50,000	9,000
Depreciation	231,821	231,821	-	250,000	18,179
Total Operating Expenses	**$ 4,949,321**	**$ 4,949,321**	**$ -**	**$ 4,838,800**	**$ (110,521)**
Total Direct Expenses	**$ 15,455,866**	**$ 15,455,866**	**$ -**	**$ 15,534,203**	**$ 78,338**
Indirect Expenses	**$ (427,047)**	**$ (427,047)**	**$ -**	**$ (413,149)**	**$ 13,898**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 15,028,819**	**$ 15,028,819**	**$ -**	**$ 15,121,054**	**$ 92,236**
Change in Assets	**$ (548,622)**	**$ (548,622)**	**$ -**	**$ (637,357)**	**$ (88,735)**
Fixed Assets					
Depreciation	$ (231,821)	$ (231,821)	$ -	$ (250,000)	$ (18,179)
Computer & Software CapEx	276,000	276,000	-	276,000	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	-	-	-	0	-
Inc(Dec) in Fixed Assets (C)	**44,179**	**44,179**	**-**	**26,000**	**(18,179)**
TOTAL BUDGET (=B+C)	**$ 15,072,998**	**$ 15,072,998**	**$ -**	**$ 15,147,054**	**$ 74,057**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (592,801)**	**$ (592,801)**	**$ -**	**$ (663,357)**	**$ (70,556)**

(1) $0 of penalty sanctions collected to date and prior to June 30, 2015.

(2) 2015 Projections reflect expectations based on the 1st quarter statement of activities. It is anticipated that projections could change throughout 2015 and would be reflected in each subsequent quarter's statement of activities.

Section A – Regional Entity Division
2017 Business Plan and Budget



Section A — 2017 Regional Entity Division Business Plan and Budget

Reliability Standards Program

Reliability Standards Program Resources (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)
Total FTEs	2.93	1.93	-1.00
Direct Expenses	$913,958	$658,082	($255,877)
Indirect Expenses	$584,695	$372,606	($212,089)
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($11,234)	($8,359)	$2,875
Total Funding Requirement	$1,487,419	$1,022,328	($465,091)

Program Scope and Functional Description

The NPCC Reliability Standards Program Area operates in accordance with NPCC's filed and approved Delegation Agreement "Exhibit C", and NERC Rules of Procedure Section 300. The program supports the ERO standards program area roles and responsibilities, the 2017 ERO Enterprise Strategic Plan and 2017-2019 Shared Business Plan and Budget Assumptions. NPCC's Reliability Standards Program Area provides supporting activities for stakeholders and the ERO for the development of 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. The 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 a Regional level, the standards program develops, and maintains NPCC Regional Reliability Standards, ERO Standards Variances for the northeast as required, and ensures that NPCC's Regional reliability criteria, contained in the form of Directories, are "not inconsistent with" any applicable NERC and Regional Reliability Standards, in accordance with 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 supports the NERC Enhanced Periodic Review process to review existing NERC standards and participates directly in the activities of the NERC Standing Periodic Review Team to grade existing standards. The NPCC Regional 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 2016 NPCC developed feedback mechanisms from the Compliance, Event Analysis, RAPA and

Criteria Services program area which will provide 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. To ensure transparency and stakeholder input, many of the activities of the NPCC Reliability Standards Program Area are conducted with oversight and participation from the NPCC Regional Standards Committee (RSC).

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 2017-2019 Reliability Standards Development Plan
- Participating in the Enhanced Periodic Review Standing Team for NERC reliability standards which will evaluate the need to revise existing standards
- Providing a forum for all NPCC representatives on the NERC drafting teams to raise issues, socialize concepts, 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
- 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 feedback mechanisms from Compliance, Event Analysis and RAPA to 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 with Standards Program Areas from other Regions.
- Developing and maintaining Regional Standards as necessary to address Regional reliability related issues or risks and ensure those standards are "not inconsistent with" the NERC continent wide standards.
- 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.

2017 Key Assumptions

- Facilitate stakeholder review, comment on, and develop ballot recommendations or list of Regional issues, for all NERC Reliability Standards Projects under development or revision prior to the end of ballots
- Participate in the northeast stakeholder efforts to develop Standards Authorization Requests (SARs) and Regional SARs to further improve standards in response to any potential inadequacies in reliability or to improve or correct standards.

- Continually review reliability requirements of ERO and NPCC Regional Standards, NPCC Criteria and ensure consistency and alignment, remove redundancies, and adopt revised Functional Model language when appropriate.
  o
- Review all FERC orders and provincial regulations as they relate to the standards, their revision and adoption
- Conduct and support regulatory and/or governmental provincial filings on a periodic basis based on individual provincial laws and requirements outlined in the Memorandum of Understandings for each province.
  o
- Enhance NPCC standards website pages to provide uniform and clear information to the stakeholders while also providing the historical and archived information to support NERC and FERC approvals and expanding requirements

2017 Goals and Key Deliverables

The Reliability Standards program goals and objectives for 2017 are grouped into six categories:

1) Participate in the ERO Results-Based Standards Development

- Participate in the development and revision of the NERC three year Reliability Standards Development Plan through review, commenting, and other RSC activities
- Participate in the NERC Standards Committee strategic initiatives to measure the effectiveness and quality of standards, participate in standards EPR activities, and address any outstanding FERC Directives.
- Support cost effectiveness (CRRA), timely development, and quality of content attributes of new 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
- 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 potential member's comments on FERC staff informal assessments as appropriate
- Participate in pre-ballot reviews of ERO standards and provide 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
- Review and identify issues on 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 NERC's Standards Committee prioritization process, to identify immediate standards needs and prioritize standards projects based on need
- Participate in the NERC RISC by providing a regional point of contact for all potential reliability related risks and gaps within the Northeast or as noted by NPCC stakeholders
- Participate in and provide support to critical standards, such as CIP, Balancing Authority Controls, Voltage and Reactive Control, Real Time Tools, Frequency Response, etc.
- Identify and initiate regional Variances to the NERC Reliability Standards as soon as possible, allowing incorporation into the continent wide standard at its inception
- Identify potential drivers for standards revisions based on revisions to the BES to a bright line criteria and any document revisions required as a result of consideration of the "Exception Process".
- Provide continued insights to NERC, based on NPCC experiences, regarding strategy for developing cost effectiveness analysis for standards and support activities to enhance this to identify "benefits" for the draft standards.
- 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 regional feedback mechanisms with Compliance, RAPA, Event Analysis, etc.
- Provide support to the Compliance Guidance Policy activities.

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
- 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 reviews of regional standards as necessitated by the revision and approval of any associated Continent-wide NERC reliability standards

3) Standards Improvement

- Achieve NPCC Northeastern North American reliability goals and objectives by initiating, participating in, and efficiently completing standards related activities
- 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 and initiate implementation

- Continually identify additional future Regional Standard opportunities if continent-wide standards are not an appropriate 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 to determine if an adequate level of reliability is being achieved through the Enhanced Periodic Review Standing Team activities
- Support and develop cost-effectiveness CRRA analysis activities to determine if any potential incremental increases in costs of implementing a standard have sufficient enough reliability benefit to implement that standard
- 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

5) Opportunities for Process Improvement

- Review the NERC Standards Development Process for possible revisions to consider efficient and effective standards development and CRRA while maintaining the ANSI accreditation for standards development
- Refine the records retention programs to ensure sufficient documentation exists for regulatory approvals
- Develop and implement document management systems to allow the efficient and effective revisions of documents, control of authorship and security of documents
- Identify improvements in process for feedback loops to ensure that event analysis, investigation lessons learned, and compliance issues involving violations are fed into the standards program area, as appropriate for review and potential consideration when revising standards
- Support the Functional Model Advisory Group activities to refine functions, tasks and responsibilities of applicable entities as needed
- Solicit and provide outreach to FERC in future revisions to the Regional Standard Processes Manual

6) Communications

- Improve the notifications process to assure awareness of dates and proceedings of all standard development activities
- Strengthen the relationship with the industry's technical committees to ensure adequate input to standards development, such as the North American Generator Forum.
- Participate in NPCC and NERC workshops as necessary, to provided outreach, promote awareness and educate the industry on standards related activities
- Participate in consensus building activities and notification process(es) to engage stakeholders and provide notification to NPCC's subject matter experts for the need to

review standards. Provide the associated coordination for this review utilizing subject matter experts, both internal and external to the Regional Entity staff

- Promote the requirements and reliability objectives of the NERC standards as appropriate to the NPCC members of the NERC Registered Ballot Body in order to achieve consensus and support of beneficial standards and to promote the ERO Enterprise.

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

- Reallocation of staff during 2016 resulted in a decrease of one full time employee in the Reliability Standards program. NPCC anticipates no need to hire additional personnel in this program area in 2017.

Consultants and contracts

- Consultant and contractor costs are expected to remain at 2016 levels due to a full complement of staff and internal subject matter expertise to evaluate standards and criteria and fulfill all ERO delegated functions assigned to the Reliability Standards Program Area.

Reliability Standards Program

Funding sources and related expenses for the Reliability Standards section of the 2017 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
2016 Budget & Projection, and 2017 Budget

Reliability Standards

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 1,480,373	$ 1,480,373	$ -	$ 1,022,328	$ (458,045)
Penalty Sanctions	7,046	7,046	-	-	(7,046)
Total ERO Funding	**$ 1,487,419**	**$ 1,487,419**	**$ -**	**$ 1,022,328**	**$ (465,091)**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 1,487,419**	**$ 1,487,419**	**$ -**	**$ 1,022,328**	**$ (465,091)**
Expenses					
Personnel Expenses					
Salaries	$ 548,639	$ 548,639	$ -	$ 370,220	$ (178,419)
Payroll Taxes	32,229	32,229	-	21,273	(10,956)
Benefits	116,140	116,140	-	97,411	(18,729)
Retirement Costs	61,950	61,950	-	43,020	(18,929)
Total Personnel Expenses	**$ 758,958**	**$ 758,958**	**$ -**	**$ 531,925**	**$ (227,034)**
Meeting Expenses					
Meetings	$ 20,000	$ 20,000	$ -	$ 13,000	$ (7,000)
Travel	125,000	125,000	-	103,157	(21,843)
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 145,000**	**$ 145,000**	**$ -**	**$ 116,157**	**$ (28,843)**
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	**$ 913,958**	**$ 913,958**	**$ -**	**$ 658,082**	**$ (255,877)**
Indirect Expenses	**$ 584,695**	**$ 584,695**	**$ -**	**$ 372,606**	**$ (212,089)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 1,498,654**	**$ 1,498,654**	**$ -**	**$ 1,030,688**	**$ (467,966)**
Change in Assets	**$ (11,234)**	**$ (11,234)**	**$ -**	**$ (8,359)**	**$ 2,875**
Fixed Assets					
Depreciation	$ -	-	$ -	-	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(11,234)	(11,234)	-	(8,359)	2,875
Inc(Dec) in Fixed Assets (C)	**(11,234)**	**(11,234)**	**-**	**(8,359)**	**2,875**
TOTAL BUDGET (=B+C)	**$ 1,487,419**	**$ 1,487,419**	**$ -**	**$ 1,022,328**	**$ (465,091)**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ 0**	**$ 0**	**$ -**	**$ 0**	**$ 0**

Compliance Monitoring and Enforcement and Organization Registration and Certification Program

Compliance Monitoring and Enforcement and Organization Registration and Certification Program Resources (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)
Total FTEs	16.00	17.00	1.00
Direct Expenses	$5,367,667	$5,366,656	($1,011)
Indirect Expenses	$3,192,876	$3,282,024	$89,148
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$89,653	$77,369	($12,284)
Total Funding Requirement	$8,650,196	$8,726,049	$75,853

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; Compliance Enforcement; and Compliance Investigation:

Compliance Implementation, Registration and Certification

The Compliance Implementation and Registration sub-program is responsible for:

a) Using the risk-based registration model to maintain an accurate registry assuring that all entities that are required to meet the NERC and Regional Reliability Standards have been identified.
b) Engaging with those registered entities who are requesting that a reduced number of requirements be applicable to them based on registration materiality and other considerations;
c) Representing NPCC on the NERC –led Review Panel whose role is to make decisions related to resolving any identified registration issues;
d) Development and maintenance of all CMEP Compliance Procedures, Compliance Instructions and all other CMEP related documentation;
e) Development and maintenance of 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;
f) 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.
g) Day-to-day implementation of the CMEP;
h) Development of annual CMEP Implementation Plan;
i) Monitoring and assessment of guided self-certification, self-report, exception reporting, periodic data and complaint submittals;
j) Development and maintenance of CMEP Data Administration Application (CDAA);
k) Development and maintenance of compliance website.
l) Continue to support the anticipated expansion of the number of registered entities in NPCC due to the implementation of the FERC Order related to the definition of Bulk Electric System
m) Conduct certification(s) of newly identified Transmission Operators (TOPs) and the re-certification of entity modifications, as needed.
n) Maintain database of BES assets subject to NERC and NPCC Reliability Standards
o) Participation 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. 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 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 Inherent Risk Assessment (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 predefined 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 is the basis for CMEP engagement scoping. They conduct an entity's Inherent Risk Assessment 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 reducing requirements of the engagement. Internal Controls Evaluation (ICE) is voluntary and must be agreed to by the entity.

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 will strive 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 will promote 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;
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 violations;
f) Coordinate 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 Stands Program Area
g) Follow 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) Develop and monitor a set of enforcement metrics that support NERC's Strategic Plan and Oversight Program

2017 Key Assumptions and Cost Impacts

2016	Projected 2017
4 Large On-Site Audits	4 On-Site O&P Audits
9 On-Site CIP Audits	5 On-Site CIP Audits
5 Large Off-Site Audits	30 Off-Site O&P Audits
15 Medium Off-Site Audits	
10 Small Off-Site Audits	
24 Off-Site CIP Audits	25 Off-Site CIP Audits
150 Spot Checks	15 Spot Checks
	25 Guided self-certifications
	35 Inherent Risk Assessments
	10 On-site Internal Control Evaluations
4 TFE Part B reviews	4 On-Site TFE Reviews
100 Violations (Estimated)	100 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 2017.

- 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 Quebec and the continuing role of implementing the NB CMEP in New Brunswick.
- The 2017 Business Plan projects no increases in Enforcement Processing activities over the 2016 Budget.
- The 2017 Business Plan projects the need for 1 Compliance Investigation. These Compliance Investigations are manpower intensive for NPCC staff (requiring allocation of more resources and potentially higher than normal costs)

2017 Goals and Key Deliverables

- Conduct 2017 CMEP consistent with a risk-based compliance monitoring and enforcement model, assessing Inherent Risk Assessment; conducting voluntary Internal Control Evaluation; and expanding the use of compliance exceptions and the self-logging program for disposition of minimal violations. The CMEP would monitor and enforce all applicable NERC Reliability Standards and applicable Regional Reliability Standards.

  - 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.
- Review and revise NPCC Compliance Registry based on FERC approved risk-based approach ;
- Evaluate CMEP and Canadian entity compliance program implementation with the objective of establishing a long-term strategy for compliance improvement, and initiate the implementation of the long term strategy;
- 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 of, and approve mitigation plans and mitigating activities;
- Conduct 2017 Compliance Engagement Schedule based on risk to the BES and number of registered entities and promote RAI 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;
- On-site CIP audits may be combined with scheduled 2017 on-site audits;
- 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 violations;
- 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;
- Enhance the CDAA to expand its capabilities from both the registered entity perspective and the NPCC Compliance staff perspective;
- Conduct 2017 Compliance Workshops and interim information sessions for registered entities as necessary as a part of 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 57% of its resources on this activity.

Resource Requirements

Personnel

- There is an increase of one FTE in 2017 from the 2016 budget. This is the result of reprioritization during 2016 based on the increased activity in the Compliance area related to risk based initiatives and the ongoing effort to reduce consulting and contractor expenses.

Consultants and contracts

- In 2017, contractor costs will continue to decrease due to the implementation of the risk-based approach in 2015. 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 2017 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
2016 Budget & Projection, and 2017 Budget
Compliance Monitoring and Enforcement and Organization Registration and Certification

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 8,611,718	$ 8,611,718	$ -	$ 8,726,049	$ 114,331
Penalty Sanctions	38,478	38,478	-	-	(38,478)
Total ERO Funding	**$ 8,650,196**	**$ 8,650,196**	**$ -**	**$ 8,726,049**	**$ 75,853**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 8,650,196**	**$ 8,650,196**	**$ -**	**$ 8,726,049**	**$ 75,853**
Expenses					
Personnel Expenses					
Salaries	$ 2,494,251	$ 2,494,251	$ -	$ 2,749,908	$ 255,657
Payroll Taxes	166,018	166,018	-	179,504	13,487
Benefits	491,904	491,904	-	519,457	27,553
Retirement Costs	268,494	268,494	-	290,486	21,992
Total Personnel Expenses	**$ 3,420,667**	**$ 3,420,667**	**$ -**	**$ 3,739,356**	**$ 318,689**
Meeting Expenses					
Meetings	$ 32,000	$ 32,000	$ -	$ 23,800	$ (8,200)
Travel	355,000	355,000	-	329,500	(25,500)
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 387,000**	**$ 387,000**	**$ -**	**$ 353,300**	**$ (33,700)**
Operating Expenses					
Consultants & Contracts	$ 1,560,000	$ 1,560,000	$ -	$ 1,274,000	$ (286,000)
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 1,560,000**	**$ 1,560,000**	**$ -**	**$ 1,274,000**	**$ (286,000)**
Total Direct Expenses	**$ 5,367,667**	**$ 5,367,667**	**$ -**	**$ 5,366,656**	**$ (1,011)**
Indirect Expenses	**$ 3,192,876**	**$ 3,192,876**	**$ -**	**$ 3,282,024**	**$ 89,148**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 8,560,543**	**$ 8,560,543**	**$ -**	**$ 8,648,680**	**$ 88,137**
Change in Assets	**$ 89,653**	**$ 89,653**	**$ -**	**$ 77,369**	**$ (12,284)**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	151,000	151,000	-	151,000	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(61,347)	(61,347)	-	(73,631)	(12,284)
Inc(Dec) in Fixed Assets (C)	**89,653**	**89,653**	**-**	**77,369**	**(12,284)**
TOTAL BUDGET (=B+C)	**$ 8,650,196**	**$ 8,650,196**	**$ -**	**$ 8,726,049**	**$ 75,853**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ -**	**$ -**	**$ -**	**$ (0)**	**$ (0)**

Reliability Assessment and Performance Analysis Program

Reliability Assessment and Performance Analysis Program Resources (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)
Total FTEs	5.83	5.83	0.00
Direct Expenses	$2,030,523	$2,106,675	$76,152
Indirect Expenses	$1,163,404	$1,125,541	($37,863)
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($22,353)	($25,251)	($2,898)
Total Funding Requirement	$3,171,574	$3,206,966	$35,392

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.

2017 Key Focus Areas

In collaboration with NERC, Key Focus area activities for 2017 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 2017 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 3a. ("3a. "Risks to Reliability are identified and prioritized based on reliability impacts, cost and practicality of assessments, projected resources, and emerging issues.") 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 3d. ("3d. Reliability models and data accurately represent system behavior and are shared among stakeholders.") 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 requests for BES Processing requests for Exceptions are not expected to significantly impact resources requirements in this program area for 2017.

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

- ✓ 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 Items

- ✓ Facilitate the completion of the steady state and dynamic simulation base case data compilation and development for the 2017 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 2017 series 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;
- ✓ Verify that procedures in the MMWG manual are followed.

System Assessments

- ✓ Conduct the 2017 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.

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 could include:

- ✓ Essential Reliability Services Working Group (ERSWG);
- ✓ Distributed Energy Resources Task Force (DERTF);
- ✓ Load Modeling Task Force (LMTF);
- ✓ Protection System Mis-operations Task Force (PSMTF);
- ✓ Spare Equipment Working Group (SEWG);
- ✓ Demand Response Availability Data System Working Group (DADSWG);
- ✓ Generating Availability Data System Working Group (GADSWG);
- ✓ Transmission Availability Data System Working Group (TADSWG);
- ✓ Modeling Working Group (MWG);
- ✓ Reliability Assessment Subcommittee (RAS);
- ✓ 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 2017 NERC Long-Term Reliability Assessment through the NPCC 2017 Long Range Adequacy Overview.

ERO – Executive Management Group (EMG) 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.

2017 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 Task Force.

Key TFCP Reliability Assessment and Performance Analysis Deliverables:

- Coordinate NPCC responses to NERC Essential Reliability Services Task Force recommendations with the Task Force on Coordination of Operation and the Task Force on System Studies to ensure that developments in the NERC PC 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 (RSC);
- Monitor the development of Bulk Power System (BPS) Regional Standard;
- Monitor the actions of the NERC Systems Analysis and Modeling Subcommittee (SAMS) in the areas of resource adequacy, system protection and system control;
- Oversee the Directory No. 1 Implementation Plan (Dated: September 30, 2015);
- Conduct the annual NPCC Interregional Long Range Adequacy Overview and associated NERC ProbA
- Lead the NPCC Task Forces in reviewing and revising the *A10 Criteria*– NPCC Classification of Bulk Power System Elements;
- Evaluate and approve Area Transmission Reviews;
- Evaluate and approve Area Reviews of Resource Adequacy;
- Coordinate, monitor, review, and make recommendations on the retirement of existing in-service Special Protection Systems (SPS); and the implementation of proposed new or modified Special Protection Systems;
- Review the practice within the NPCC for the use of an SPS with input from the other task force groups;
- Support related reliability activities, including consideration of any requests for sub-regional assessments associated with implementation of the U.S. EPA Clean Power Plan;.
- 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;
- Coordinate to ensure that further UVLS analysis beyond the initial feasibility/screening study is completed according to schedules set by the RCC and the NERC PC;
- Conduct a review of NPCC Interconnection Assistance Reliability Benefits;.
- Monitor the actions of applicable NERC Subcommittees in the areas of resource adequacy, system protection and system control;
- Review the load shape assumption used in NPCC 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;
- Keep informed on studies and developments with neighboring systems which might impact NPCC;
- 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);

- Facilitate Wide-Area Planning through participation in regional activities and coordinate inter-Area reliability analysis;
- 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;
- 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 Task Force.

Key TFSS Reliability Assessment and Performance Analysis 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, as appropriate;
- ✓ Review and classify new and modified Special Protection Systems, 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 a review and revision of the A-10 document in 2016.
  - 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 bi-annual review and update of the Major Project List;
- ✓ Participate in the development and submission of NPCC comments/inputs into the development of regional and/or continent-wide reliability standards that address the NERC Reliability Standards.
- ✓ As RCC directs, provide support and technical input, for Task Force related BES risks as identified by the NERC Reliability Issues Steering Committee "RISC";
- ✓ Update the NPCC Electric System Map.

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:

- ✓ On an as needed basis, update SS-37 Procedure Manual and other SS-37 documents including the Master Tieline Data and Interchange Schedule;
- ✓ provide mid-term updates to the ten-year-out cases in the NPCC Library;
- ✓ Coordinate with SS-38 to support the performance of event replication by benchmarking against actual system performance;
- ✓ Review existing regional criteria and procedures for validation of data used in power flow and dynamic simulations. If the existing criteria or procedures are found to be deficient, and propose changes to provide for adequate data validation.
- ✓ Coordinate management of governor models used in studies with the SS-38 Working Group.

Through the SS-38 Working Group:

- ✓ Complete to examine the impact of distributed generation;
- ✓ 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;
- ✓ Review and develop comment on draft NERC standards, as needed;
- ✓ Work with software vendors and NERC Modeling Working Group (MWG) to enhance the capability for dynamic simulations;
- ✓ Coordinate with SS-37 to perform event replication by benchmarking against actual system performance.

Through the SS-38 Load Modeling Working Group:

- ✓ Continue to investigate the use of dynamic load models for transient stability studies;
  - Investigate the use of load monitoring equipment to aid in the benchmarking of dynamic load models used in transient stability studies.

Task Force on System Protection (TFSP)

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 Task Force.

Key TFSP Reliability Assessment and Performance Analysis 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;

- ✓ Conduct review/development of the following Documents:
  - Document C-45 - Procedure for Analysis and Reporting of Protection System Misoperations. Update will incorporate new procedure associated with NERC Section 1600 Data Request;

- Develop a new Directory (Directory No. 11) for Disturbance Monitoring to house more specific NPCC criteria, guides, and procedures;
- Serve as lead Task Force working in conjunction with TFCP and TFSS on Directory No. 7 – NPCC Special Protection Systems revisions required to ensure consistency with the development of the new NERC standard on Remedial Action Schemes.
- Develop a New Guideline for Tele-protection Communication Reliability

✓ Review and respond to Questions, Requests for Interpretations and/or Clarifications related to NPCC Standards, Directories, and Criteria, as needed;
✓ Participate in the ongoing development and submission of NPCC inputs/comments into the development of protection related NERC Reliability Standards;
✓ Review NPCC misoperations of protection systems and Special Protection System (aka Remedial Action Schemes) and participate in providing the NPCC input for NERC Metric ALR4-1 on Protection Misoperations;
✓ Review and analyze the performance of protection systems of power system disturbances, lessons learned, and events inside as well as outside NPCC;
✓ Support NERC in its effort through the ERO-RAPA group to continue relay misoperations performance analysis to reduce protection system misoperations, inform the RCC on relay misoperations trends, and share good practices;
✓ Review mitigations and/or progress reports for BPS Risk Reduction Implementation and annually report to the RCC on the status of this implementation;
✓ 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 the NERC Risk Control Process;
✓ Collaborate with System Studies on development of disturbance monitoring recommendation for load transformers as part of effort to develop Directory No. 11; and,
✓ Maintain ongoing log of protection relay failures.

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 Task Force.

Key TFCO Reliability Assessment and Performance Analysis Deliverables:

✓ Review and analyze the performance of Simultaneous Activation of Reserve (SAR) implementation following an event to enhance the SAR process;'
✓ Provide recommendations to enhance the programs of annual the spring and autumn NPCC System Operator Seminars;
✓ Share lessons learned among training staff from the NPCC RCs and utilize to make training program enhancements;
✓ Develop and securely disseminate the annual compilation of "Facilities for Notification."
✓ Present to the TFCO an annual summary of operating tool failures and lessons learned for the preceding year;

- ✓ Perform a voluntary Critical Operating Tool Analysis Survey accompanied with the previous surveys recommendation to disseminate and assess the implementation of best practices and recommendations;
- ✓ Complete a triennial review of the RC area restoration plans;
- ✓ Support an annual enhanced, wide area restoration drill among the Reliability Coordinator areas of NPCC and their neighboring Reliability Coordinators incorporating the annual review of the NPCC regional restoration plan;
- ✓ Conduct pre-seasonal NPCC Reliability Assessments incorporating multi-area probabilistic reliability simulation results in each assessment. Coordinate the NPCC input for the annual data for the NERC Reliability Assessment Subcommittee.
- ✓ Conduct reviews of applicable NPCC Directories, Criteria, Guides and Procedures in accordance with their applicable review dates:
    - Directory No. 2 – "*Emergency Operations*"
    - Directory No. 5 – "*Reserve*"
- ✓ Assess the dependency of successful system operations on current telecommunication systems.

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.

Activities for 2017 include continued outreach to NPCC's state electricity and environmental regulators stressing the importance of understanding the reliability considerations, such as the identified Essential Reliability Services when formulating State Implementation Plans for the EPA Clean Power Plan compliance. This includes focus on issues concerning regional planning, the characteristics of distributed energy resources, the timing of new generation resources and transmission infrastructure projects and use of the rule's Reliability Safety Valve.

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 21% of its resources on these activities.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2017.

Consultants and contracts

- Decrease in RAPA consulting and contracts expense is associated with the reallocation of NPCC staff in order to reduce the use of outside contractors.

Reliability Assessment and Performance Analysis Program

Funding sources and related expenses for the Reliability Assessment and Performance Analysis section of the 2017 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 2016 Budget & Projection, and 2017 Budget Reliability Assessment and Performance Analysis						
		2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 3,157,554	$ 3,157,554	$ -	$ 3,206,966	$ 49,412
	Penalty Sanctions	14,020	14,020	-	-	(14,020)
Total ERO Funding		**$ 3,171,574**	**$ 3,171,574**	**$ -**	**$ 3,206,966**	**$ 35,392**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 3,171,574**	**$ 3,171,574**	**$ -**	**$ 3,206,966**	**$ 35,392**
Expenses						
Personnel Expenses						
	Salaries	$ 1,031,149	$ 1,031,149	$ -	$ 1,084,994	$ 53,845
	Payroll Taxes	64,284	64,284	-	65,373	1,089
	Benefits	212,345	212,345	-	214,688	2,343
	Retirement Costs	116,395	116,395	-	121,271	4,876
Total Personnel Expenses		**$ 1,424,173**	**$ 1,424,173**	**$ -**	**$ 1,486,325**	**$ 62,152**
Meeting Expenses						
	Meetings	$ 45,000	$ 45,000	$ -	$ 20,500	$ (24,500)
	Travel	186,850	186,850	-	186,850	-
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 231,850**	**$ 231,850**	**$ -**	**$ 207,350**	**$ (24,500)**
Operating Expenses						
	Consultants & Contracts	$ 374,500	$ 374,500	$ -	$ 413,000	$ 38,500
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
	Depreciation	-	-	-	-	-
Total Operating Expenses		**$ 374,500**	**$ 374,500**	**$ -**	**$ 413,000**	**$ 38,500**
	Total Direct Expenses	**$ 2,030,523**	**$ 2,030,523**	**$ -**	**$ 2,106,675**	**$ 76,152**
Indirect Expenses		**$ 1,163,404**	**$ 1,163,404**	**$ -**	**$ 1,125,541**	**$ (37,863)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 3,193,927**	**$ 3,193,927**	**$ -**	**$ 3,232,217**	**$ 38,289**
Change in Assets		**$ (22,353)**	**$ (22,353)**	**$ -**	**$ (25,251)**	**$ (2,898)**
Fixed Assets						
	Depreciation	$ -	-	$ -	$ -	$ -
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	(22,353)	(22,353)	-	(25,251)	(2,898)
Inc(Dec) in Fixed Assets (C)		**(22,353)**	**(22,353)**	**-**	**(25,251)**	**(2,898)**
TOTAL BUDGET (=B+C)		3,171,574	3,171,574	-	3,206,966	35,392
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)	2016 Budget	2017 Budget	Increase (Decrease)
Total FTEs	0.10	0.10	0.00
Direct Expenses	$200,384	$229,785	$29,401
Indirect Expenses	$19,955	$19,306	($649)
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($383)	($433)	($50)
Total Funding Requirement	$219,956	$248,658	$28,702

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 training seminars, held twice yearly, at which: 1) potential operational problems for the coming season are discussed, 2) the implementation of NPCC Directories and NERC Standards 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 existing training techniques and methods, 2) evaluation of new techniques and training aids as they become available; 3) opportunities to consolidate training among the NPCC RCs and BAs, which includes opportunities to share training material and training sessions and 4) exchange of information on internal methods of system operator selection and training. The training activities indicated below are done in support of ERG Goal 5b. (“5b. The ERO Enterprise acquires, engages, and retains highly qualified talent suited to the mission.”)

Funding Drivers and Reliability Benefits

- Provide two high-quality continuing education seminars for system operators
    - System operators participating in the Seminars: 1) get exposure to NPCC issues and current industry operations topics, 2) review recent NPCC or major external disturbances, and 3) review key operations-related content in NPCC Directories and NERC Standards, and 4) participate in hands on “table top exercises”

pertaining to system operation practices. PJM system operators and trainers are also invited to and normally attend and participate in 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
    - The seminars help to improve system operation coordination through better contact among operators
- Continually review and revise the curriculum of the training seminars to better emphasize NERC standards, Regional Standards and business practices, 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 Systematic Approach to Training (SAT) requirement for operations support staff in PER-005-2.
- NPCC will conduct two Standards and Compliance workshops in 2017, 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).

2017 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 also considering expanding the use of on-line webinars. These webinars will focus on a specific topic pertinent to developments related to compliance program implementation, standards development or technical topics.

NPCC also regularly conducts spring and fall System Operator Seminars. These seminars involve system operators from the NPCC RC/BA Areas and PJM. These will be held in early May and early November.

2017Goals and Key Deliverables

- Prepare and conduct the 2017 Spring and Fall NPCC System Operator Seminars.
- Implement the PER-005-2 expanded SAT training requirements within the NPCC RC/BA Area programs.

- Expand the content of the Reliability Coordinator training programs, to meet the requirements generated by PER-005-2, as necessary.
- 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. Create and expand the restricted-access 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".
- Participate in NERC Staff Training Group activities and provide NPCC input to the development of training policies by this group.

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 2017.

Training, Education, and Operator Certification Program

Funding sources and related expenses for the training, education, and operator certification section of the 2017 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
2016 Budget & Projection, and 2017 Budget
Training, Education, and Operator Certification

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 155,715	$ 155,715	$ -	$ 184,658	$ 28,943
Penalty Sanctions	240	240	-	-	(240)
Total ERO Funding	**$ 155,956**	**$ 155,956**	**$ -**	**$ 184,658**	**$ 28,702**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	64,000	64,000	-	64,000	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 219,956**	**$ 219,956**	**$ -**	**$ 248,658**	**$ 28,702**
Expenses					
Personnel Expenses					
Salaries	$ 19,073	$ 19,073	$ -	$ 21,012	$ 1,939
Payroll Taxes	1,311	1,311	-	1,396	85
Benefits	5,452	5,452	-	4,801	(651)
Retirement Costs	2,397	2,397	-	2,641	244
Total Personnel Expenses	**$ 28,234**	**$ 28,234**	**$ -**	**$ 29,850**	**$ 1,616**
Meeting Expenses					
Meetings	$ 157,000	$ 157,000	$ -	$ 186,300	$ 29,300
Travel	15,150	15,150	-	13,635	(1,515)
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 172,150**	**$ 172,150**	**$ -**	**$ 199,935**	**$ 27,785**
Operating Expenses					
Consultants & Contracts	$ -	$ -	$ -	$ -	$ -
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Direct Expenses	**$ 200,384**	**$ 200,384**	**$ -**	**$ 229,785**	**$ 29,401**
Indirect Expenses	**$ 19,955**	**$ 19,955**	**$ -**	**$ 19,306**	**$ (649)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 220,339**	**$ 220,339**	**$ -**	**$ 249,091**	**$ 28,752**
Change in Assets	**$ (383)**	**$ (383)**	**$ -**	**$ (433)**	**$ (50)**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(383)	(383)	-	(433)	(50)
Inc(Dec) in Fixed Assets (C)	**(383)**	**(383)**	**-**	**(433)**	**(50)**
TOTAL BUDGET (=B+C)	219,956	219,956	-	248,658	28,702
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)	2016 Budget	2017 Budget	Increase (Decrease)
Total FTEs	3.00	4.00	1.00
Direct Expenses	$956,690	$1,188,137	$231,447
Indirect Expenses	$598,664	$772,241	$173,577
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($11,503)	($17,325)	($5,822)
Total Funding Requirement	$1,543,852	$1,943,053	$399,201

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.

Event Analysis Program

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.

Situational Awareness

Operational Status

On an ongoing, but non-real time basis, NPCC monitors the operational status of the bulk power system and coordinates normal and pre-emergency communication, awareness and assistance in addition to the same during an emergency among the Reliability Coordinators within NPCC: the New Brunswick Power Corporation, Hydro-Québec Contrôle de mouvements d'énergie (HQCMÉ, a division of Hydro-Québec TransÉnergie), the ISO New England, Inc., the New York ISO and the Independent Electricity System Operator in Ontario; and its neighboring RCs: the Midcontinent ISO and PJM. The industry is notified 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.

The "NPCC Emergency Preparedness Conference Call Procedures" provide a mechanism that enables the Reliability Coordinator in NPCC, and, as circumstances may require, their counterparts in neighboring Regions, to rapidly communicate the status of current operating conditions, to facilitate the procurement of assistance during emergency conditions and to identify potential physical or cyber threats to the system.

Items of particular concern that can be discussed during the calls may include, but are not limited to, the following: anticipated weather conditions critical to the system or systems experiencing or projecting resource deficiencies; load forecast; largest first and second contingencies; potential need for emergency transfers; operating reserve requirements and expected available operating reserve capacity deficiencies; potential fuel shortages or potential fuel supply disruptions which could lead to energy shortfalls; identified or projected voltage conditions; status of short term transactions; additional capability available within four hours and additional capability available within twelve hours; generator outages; significant transmission outages; expected transfer limits and limiting elements; anticipated implementation of NERC Transmission Loading Relief (TLR); changes in the status of relay protection systems; arming of special protection systems not normally armed; and/or the application of abnormal operating procedures.

NPCC has also established 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.

NPCC also monitors 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.

To ensure the capability for continued voice communications among NPCC and its Reliability Coordinators, a satellite telephone network was also established, and it is tested on a monthly basis. 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.

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)
- 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 2017 critical infrastructure goals and objectives, supporting ERO Goal 3.c:

- Monitor the Homeland Security Information Network (HSIN), E- ISAC, NERC Alerts and Canadian Information Sharing and share information with NPCC's CO-8 System Operations Managers 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' and others applicable security recommendations and requirements, and keep the RCC and its committees appropriately informed, e.g. Sector Specific Plan.
- Review infrastructure security & technologies and provide recommendations to RCC to enhance physical and cyber security in compliance with NERC guidelines/standards
- Provide recommendations to RCC 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.
- Since RCC approved the Cross Border Emergency Telecommunications recommendation, insure that suggested annual testing happens and each Area can communicate with each other. [IST-2]
- As RCC directs, 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. 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

System Operations Security Objectives

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
- Assisting in the development of real time operating tools assuring cyber security concerns are addressed

2017 Key Assumptions

- 2017The monitoring of Lessons Learned will continue to be a major focus of NERC in 2017. 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 2017.
- 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 satisfactory responded to by the version 5 Transition Advisory Group.

2017 Goals and Key Deliverables

- Monitor the reliable implementation of version 5 of the Cyber Standards.
- 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).
- Take part in the planning of, preparation for and participation in the bi-annual GridEx IV exercise, incorporating the Lessons Learned generated by the GridEx III 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.

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 13% of its resources on this activity.

Resource Requirements

Personnel

- Reallocation of staff during 2016 resulted in an increase of one full time employee in the Situation Awareness and Infrastructure Security program to support increased workload in this area.
- NPCC anticipates no need to hire additional personnel in this program area in 2017.

Situation Awareness and Infrastructure Security Program

Funding sources and related expenses for the situation awareness and infrastructure security section of the 2017 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
2016 Budget & Projection, and 2017 Budget
Situation Awareness and Infrastructure Security

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 1,536,637	$ 1,536,637	$ -	$ 1,943,053	$ 406,416
Penalty Sanctions	7,215	7,215	-	-	(7,215)
Total ERO Funding	**$ 1,543,852**	**$ 1,543,852**	**$ -**	**$ 1,943,053**	**$ 399,201**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 1,543,852**	**$ 1,543,852**	**$ -**	**$ 1,943,053**	**$ 399,201**
Expenses					
Personnel Expenses					
Salaries	$ 516,951	$ 516,951	$ -	$ 660,213	$ 143,262
Payroll Taxes	32,630	32,630	-	42,778	10,148
Benefits	116,230	116,230	-	160,814	44,584
Retirement Costs	53,880	53,880	-	72,333	18,453
Total Personnel Expenses	**$ 719,690**	**$ 719,690**	**$ -**	**$ 936,137**	**$ 216,447**
Meeting Expenses					
Meetings	$ 15,000	$ 15,000	$ -	$ 13,500	$ (1,500)
Travel	65,000	65,000	-	78,500	13,500
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 80,000**	**$ 80,000**	**$ -**	**$ 92,000**	**$ 12,000**
Operating Expenses					
Consultants & Contracts	$ 157,000	$ 157,000	$ -	$ 160,000	$ 3,000
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 157,000**	**$ 157,000**	**$ -**	**$ 160,000**	**$ 3,000**
Total Direct Expenses	**$ 956,690**	**$ 956,690**	**$ -**	**$ 1,188,137**	**$ 231,447**
Indirect Expenses	**$ 598,664**	**$ 598,664**	**$ -**	**$ 772,241**	**$ 173,577**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 1,555,355**	**$ 1,555,355**	**$ -**	**$ 1,960,378**	**$ 405,023**
Change in Assets	**$ (11,503)**	**$ (11,503)**	**$ -**	**$ (17,325)**	**$ (5,822)**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(11,503)	(11,503)	-	(17,325)	(5,822)
Inc(Dec) in Fixed Assets (C)	**(11,503)**	**(11,503)**	**-**	**(17,325)**	**(5,822)**
TOTAL BUDGET (=B+C)	1,543,852	1,543,852	-	1,943,053	399,201
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (0)**	**$ (0)**	**$ -**	**$ (0)**	**$ 0**

Administrative Services

Administrative Services Program Resources (in whole dollars)	Direct Expenses and Fixed Assets			FTEs		
	2016 Budget	2017 Budget	Increase (Decrease)	2016 Budget	2017 Budget	Increase (Decrease)
Technical Committees and Members Forum	$71,929	$72,500	$571	0.50	0.50	0.00
General and Administrative	$3,345,139	$3,495,691	$150,553	2.50	2.50	0.00
Legal and Regulatory	$639,905	$648,680	$8,775	1.00	1.00	0.00
Information Technology	$1,233,263	$1,060,675	($172,588)	3.00	2.00	-1.00
Human Resources	$176,588	$182,059	$5,471	1.00	1.00	0.00
Finance and Accounting	$519,820	$525,262	$5,442	1.00	1.00	0.00
Total Administrative Services	$5,986,643	$5,984,868	($1,775)	9.00	8.00	-1.00

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 2017 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
2016 Budget & Projection, and 2017 Budget
ADMINISTRATIVE SERVICES

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ (592,801)	$ (592,801)	$ -	$ (663,357)	$ (70,556)
Penalty Sanctions	-	-	-	-	-
Total ERO Funding	**$ (592,801)**	**$ (592,801)**	**$ -**	**$ (663,357)**	**$ (70,556)**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ (592,801)**	**$ (592,801)**	**$ -**	**$ (663,357)**	**$ (70,556)**
Expenses					
Personnel Expenses					
Salaries	$ 1,951,407	$ 1,951,407	$ -	$ 1,872,579	$ (78,828)
Payroll Taxes	102,585	102,585	-	93,995	(8,590)
Benefits	422,729	422,729	-	418,433	(4,296)
Retirement Costs	330,001	330,001	-	317,471	(12,531)
Total Personnel Expenses	**$ 2,806,722**	**$ 2,806,722**	**$ -**	**$ 2,702,478**	**$ (104,244)**
Meeting Expenses					
Meetings	$ 125,000	$ 125,000	$ -	$ 120,000	$ (5,000)
Travel	160,100	160,100	-	143,590	(16,510)
Conference Calls	47,000	47,000	-	37,000	(10,000)
Total Meeting Expenses	**$ 332,100**	**$ 332,100**	**$ -**	**$ 300,590**	**$ (31,510)**
Operating Expenses					
Consultants & Contracts	$ 122,000	$ 122,000	$ -	$ 152,000	$ 30,000
Office Rent	802,500	802,500	-	809,700	7,200
Office Costs	639,500	639,500	-	679,100	39,600
Professional Services	1,011,000	1,011,000	-	1,041,000	30,000
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	41,000	41,000	-	50,000	9,000
Depreciation	231,821	231,821	-	250,000	18,179
Total Operating Expenses	**$ 2,847,821**	**$ 2,847,821**	**$ -**	**$ 2,981,800**	**$ 133,979**
Total Direct Expenses	**$ 5,986,643**	**$ 5,986,643**	**$ -**	**$ 5,984,868**	**$ (1,775)**
Indirect Expenses	**$ (5,986,643)**	**$ (5,986,643)**	**$ -**	**$ (5,984,868)**	**$ 1,775**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0**
Change in Assets	**$ (592,801)**	**$ (592,801)**	**$ -**	**$ (663,357)**	**$ (70,556)**
Fixed Assets					
Depreciation	(231,821)	(231,821)	$ -	(250,000)	$ (18,179)
Computer & Software CapEx	125,000	125,000	-	125,000	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	106,821	106,821	-	125,000	18,179
Inc(Dec) in Fixed Assets (C)	**-**	**-**	**-**	**-**	**-**
TOTAL BUDGET (=B+C)	-	-	-	-	0
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (592,801)**	**$ (592,801)**	**$ -**	**$ (663,357)**	**$ (70,556)**

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 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.

2017 Key Assumptions

- NPCC's standing committee and subgroup structure for effective stakeholder involvement will continue in 2017
- 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 2017
- NPCC will continue to invest in technology and innovation to allow efficient collaboration on technical issues related to reliability

2017 Goals and Key Deliverables

The 2017 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.

2017 Public Information Committee Goals and Objectives

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 2017 NPCC Reliability Assessment
- 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 2017.

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 2017.

Legal and Regulatory

Program Scope and Functional Description

NPCC's professional legal services provide counsel to the President and CEO, Board of Directors, 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 2017.

Professional Services

- Professional services expense is projected to remain in line with 2016 levels.

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 (EROEMG), 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 2017 Business Plan and Budget assumes agreed-upon ERO Enterprise applications will be available and includes only NPCC costs for region specific support needs.

2017 Key Assumptions

- Continue to develop and 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.

2017 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:

- Conduct initial implementation and utilization of a document management system
- 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

- Reallocation of staff during 2016 resulted in a decrease of one full time employee in Information Technology. NPCC anticipates no need to hire additional personnel in this program area in 2017.
- Increase in operating expenses is primarily related to penetration testing, which will be conducted on an ongoing basis going forward in an effort to increase security.

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

- NPCC anticipates no need to hire additional personnel in this program area in 2017.

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.

2017 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 2017.

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 2014 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 2015 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, certain reliability assessment costs in response to U.S. only regulatory initiatives and the compliance responsibilities and authorities within the U.S., and the specific compliance responsibilities within each of the Canadian provinces within NPCC, the attendant costs of portions of the compliance program differ among the areas within the Regional Entity. Within the U.S. portion of NPCC all costs attributable to delegated (statutory) functions performed by NPCC, including all compliance functions, are assessed based on a NEL allocation. Within the Canadian portion of NPCC those costs attributable to compliance functions performed by NPCC on behalf of provincial governmental and/or regulatory authorities are allocated consistent with the unique Memoranda of Understanding or Agreements that have been entered into for those provinces. To address these different compliance regimes, NPCC developed a composite cost allocation methodology that allocates U.S. only reliability assessment and compliance costs on a fair and equitable basis within the Regional Entity.

As an initial step of that methodology, the NEL for each of the BAAs and their relative percentage to the NPCC total NEL is calculated for the most recent year for which data is available, the second previous year In order to establish the RE division funding requirements for each balancing authority area on a NEL basis for all programs except for Compliance the proposed expenses and fixed assets of all other programs are calculated and the adjustment for the RE division cash reserve requirement is identified. Any penalty monies received from NPCC registered entities within the U.S. prior to June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs. Consistent with each of the Canadian provincial MOUs and agreements, all penalty monies resulting from compliance actions within Canada, if any, would remain within the applicable province. The total budgeted fees for NPCC workshop participation are indicated as a credit, with the resultant addition being the RE division assessment, without the compliance program costs, calculated on a NEL basis.

In accordance with the *NPCC Amended and Restated Bylaws* the CS division proposed expenses and fixed assets of all programs are calculated and the adjustment for the CS division cash reserve requirement is identified, with the resultant addition being the CS division funding requirement and assessment, calculated on a NEL basis

For costs associated with the RE division compliance program, NPCC's allocation methodology apportions % of the costs for the program, attributed to CORC Fundamentals (CF), between the BAAs in the United States and Canada on a NEL basis.

Audits and Investigations (AI) related costs, representing % of the costs of the compliance program, are allocated between U.S. and Canadian BAAs in NPCC, and among the Canadian provinces, using an audit-based methodology. The audit-based methodology incorporates relative costs based on categories of compliance audits which are reflective of their size and complexity, as well as the differing compliance program implementation models that are utilized in NPCC due to the international nature of the Regional Entity. The portion allocated to the U.S. BAAs in NPCC is calculated using the audit-based methodology, and this amount is then re-allocated between the New York and New England BAAs based on their relative NEL.

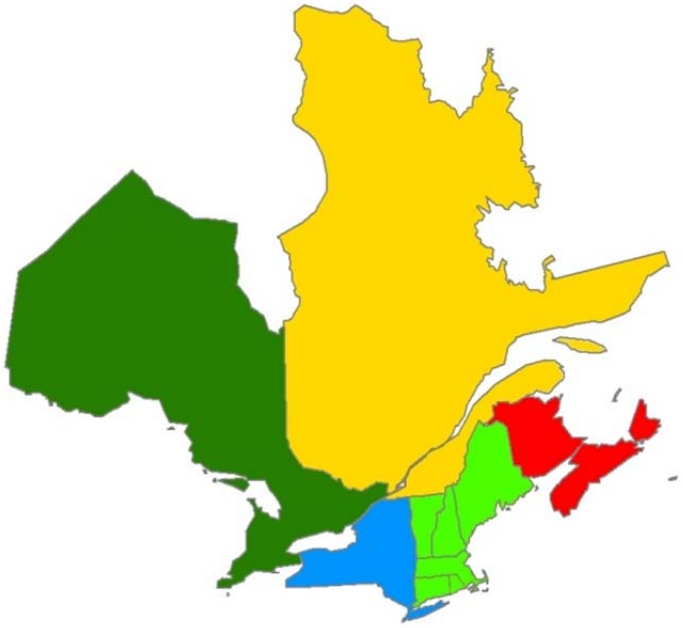
The remaining % of the costs of the compliance program represent Mitigation and Enforcement (ME) related costs and are allocated between U.S. and Canadian BAAs in NPCC, and among the Canadian provinces, using an enforcement activity based methodology,. Based on historical data, NPCC reviewed each BAAs percentage of violations, mitigation plans and settlement agreements to determine each BAAs total average percentage of enforcement activities. The portion allocated to the U.S. BAAs in NPCC is calculated using the enforcement activity based methodology, and this amount is then re-allocated between the New York and New England BAAs based on their relative NEL.

Any penalty monies received from NPCC registered entities within the U.S. by June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs, and then added to the total compliance program expenses and fixed assets to yield a total compliance program assessment.

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
2017 Business Plan and Budget



Section B — Supplemental Financial Information

Reserve Balance

Table B-1 – Reserve Balance

		Table to be Inserted			

Explanation of Changes in Reserve Policy from Prior Year

None

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 2017 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, 2016 are to be used to offset assessments in the 2017 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, 2016 through June 30, 2017 will be used to offset U.S. load serving entity designee assessments in the 2017 Budget.

All penalties received prior to June 30, 2016 are detailed below, including date received and the penalty amount.

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

		Table to be Inserted			

Table B-3 – Supplemental Funding

		Table to be Inserted			

Explanation of Significant Variances –2017 Budget versus 2016 Budget

- NPCC assumed no interest income because of continuing low market interest rates.

Table B-4 – Personnel Expenses

Table to be Inserted

Explanation of Significant Variances –2017 Budget versus 2016 Budget

Table B-5 – Meeting Expense

Table to be Inserted

Explanation of Significant Variances –2017 Budget versus 2016 Budget

Table B-6 Consultants and Contracts

		Table to be Inserted			

Explanation of Significant Variances –2017 Budget versus 2016 Budget

Table B-7 Office Rent

Table to be Inserted

Explanation of Significant Variances –2017 Budget versus 2016 Budget

Table B-8 Office Costs

Table to be Inserted

Explanation of Significant Variances –2017 Budget versus 2016 Budget

Table B-9 Professional Services

		Table to be Inserted			

Explanation of Significant Variances –2017 Budget versus 2016 Budget

Table B-10 – Miscellaneous

		Table to be Inserted			

Table B-11 Other Non-Operating Expenses

Table to be Inserted

Table B-12 Fixed Assets

		Table to be Inserted			

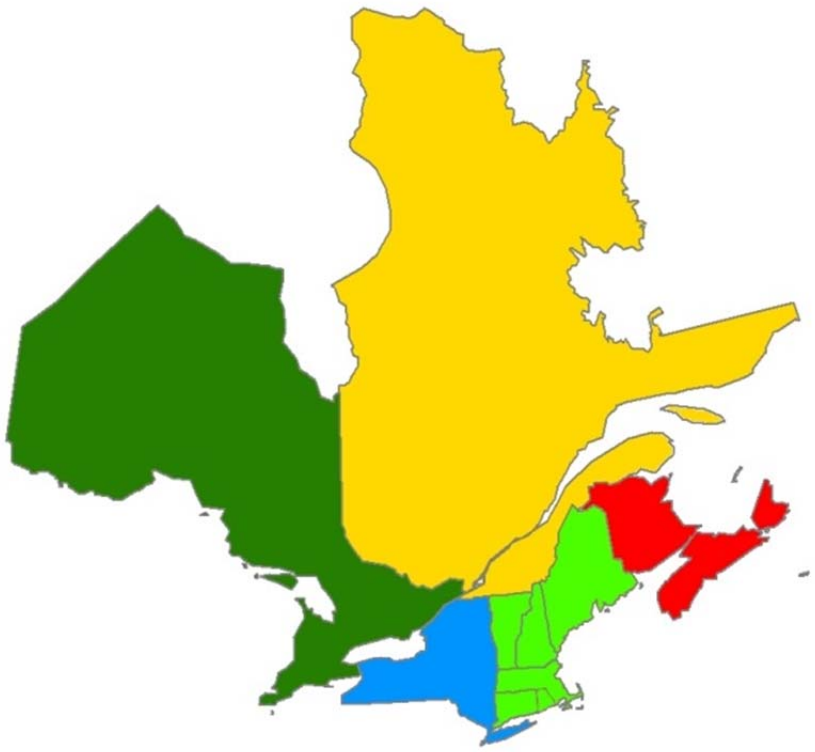
Explanation of Significant Variances –2017 Budget versus 2016 Budget

Table B-13 2017 and 2018 Projections

		Table to be Inserted			

Section C – Criteria Services Division Activities

2017 Business Plan and Budget



Section C —2017 Criteria Services Division Business Plan and Budget

Criteria Services Division (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)
Total FTEs	2.14	2.14	0.00
Total Direct Expenses	$738,525	$623,747	($114,778)
Total Indirect Expenses	$427,047	$413,149	($13,898)
Other Non-Operating Expenses	$0	$0	$0
Working Capital and Operating Reserves Requirement	($96,525)	($85,665)	$10,859
Inc(Dec) in Fixed Assets	($8,506)	($10,000)	($1,494)
Funding Requirement	$1,060,542	$941,230	($119,312)

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 2017 Assumptions and Cost Impacts

The Criteria Services division services are expected to remain stable throughout 2017

- 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 CC. in 2012.
- Past non-compliances, if any, followed the due process stated in the CCEP-1 process document and proper resolution/enforcement action taken.

2017 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 BPSBPS 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#2 –*Emergency Operations* –the TFCO will review criteria in accordance with the NPCC Reliability Assurance Program (NRAP).
    - Directory#5- *Reserve* –the TFCO will review the criteria in consideration of recent revisions to the NERC BAL standards.
    - Directory 7 – NPCC Special Protection Systems – Serve as lead Task Force working in conjunction with TFCP and TFSS on revisions required to ensure consistency with the development of the new NERC standard on Remedial Action Schemes.
    - A-10 - *Classification of Bulk Power System Elements*-the TFCP will coordinate a periodic review of the methodology in accordance with the NPCC Reliability Assurance Program (NRAP).
    - 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 2017, 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. 2016The 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.

The following Directories will either be under revision or reviewed for further development based on a schedule set forth in the NPCC Reliability Assessment Program:

NPCC Operations and Planning Directories

The following Directories are envisioned to remain active for 2017.

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 will lead this review and revision.

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 2016 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 – 2017 Budget versus 2016 Budget

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2017.

2016 Budget and Projection and 2017 Budget Comparisons

Statement of Activities and Capital Expenditures
2016 Budget & Projection, and 2017 Budget
CRITERIA SERVICES DIVISION

		2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ -	$ -	$ -	$ -	$ -
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Membership Dues	1,060,542	1,060,542	-	941,230	(119,312)
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 1,060,542**	**$ 1,060,542**	**$ -**	**$ 941,230**	**$ (119,312)**
Expenses						
Personnel Expenses						
	Salaries	$ 393,882	$ 393,882	$ -	$ 401,142	$ 7,260
	Payroll Taxes	23,275	23,275	-	23,301	26
	Benefits	88,412	88,412	-	69,100	(19,313)
	Retirement Costs	144,950	144,950	-	42,605	(102,345)
Total Personnel Expenses		**$ 650,519**	**$ 650,519**	**$ -**	**$ 536,147**	**$ (114,372)**
Meeting Expenses						
	Meetings	$ 6,500	$ 6,500	$ -	$ 5,000	$ (1,500)
	Travel	46,000	46,000	-	51,600	5,600
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 52,500**	**$ 52,500**	**$ -**	**$ 56,600**	**$ 4,100**
Operating Expenses						
	Consultants & Contracts	$ 25,000	$ 25,000	$ -	$ 18,000	$ (7,000)
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	2,000	2,000	-	3,000	1,000
	Depreciation	8,506	8,506	-	10,000	1,494
Total Operating Expenses		**$ 35,506**	**$ 35,506**	**$ -**	**$ 31,000**	**$ (4,506)**
	Total Direct Expenses	**$ 738,525**	**$ 738,525**	**$ -**	**$ 623,747**	**$ (114,778)**
Indirect Expenses		**$ 427,047**	**$ -**	**$ -**	**$ 413,149**	**$ (13,898)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,165,572**	**$ 1,165,572**	**$ -**	**$ 1,036,896**	**$ (128,677)**
Change in Assets		**$ (105,031)**	**$ (105,031)**	**$ -**	**$ (95,665)**	**$ 9,365**
Fixed Assets						
	Depreciation	$ (8,506)	(8,506)	$ -	$ (10,000)	$ (1,494)
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	-	-	-	-	-
Inc(Dec) in Fixed Assets (C)		**(8,506)**	**(8,506)**	**-**	**(10,000)**	**(1,494)**
TOTAL BUDGET (=B+C)		1,157,066	1,157,066	-	1,026,896	(130,171)
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (96,525)**	**$ (96,525)**	**$ -**	**$ (85,665)**	**$ 10,859**

Personnel Analysis

Total FTE's by Program Area	Budget 2016	Projection 2016	Direct FTEs 2017 Budget	Shared FTEs1 2017 Budget	Total FTEs 2017 Budget	Change from 2016 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 2016 - 2017

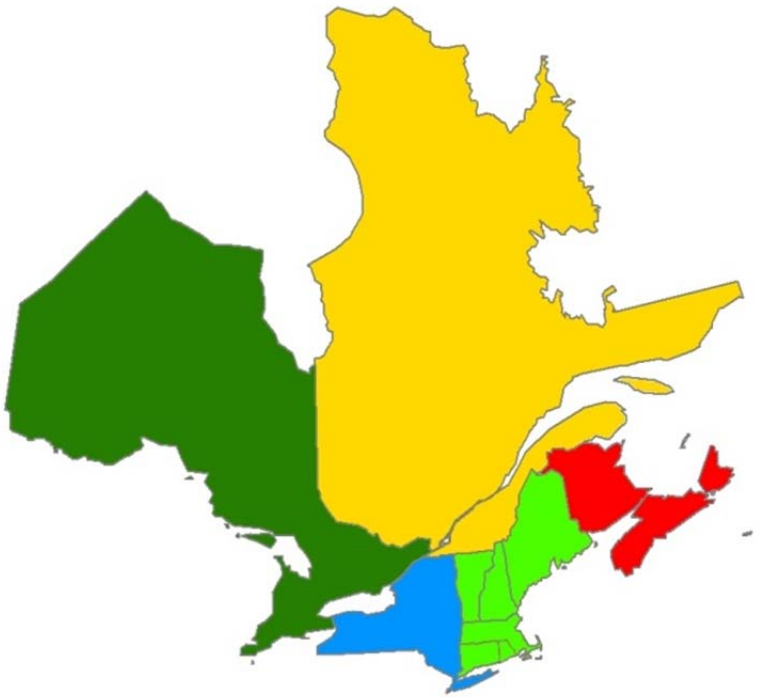
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Explanation of Changes in Reserve Policy from Prior Year

None

Section D – Additional Consolidated Financial Statements

2017 Business Plan and Budget



Section D — Additional Financial Statements

Statement of Financial Position

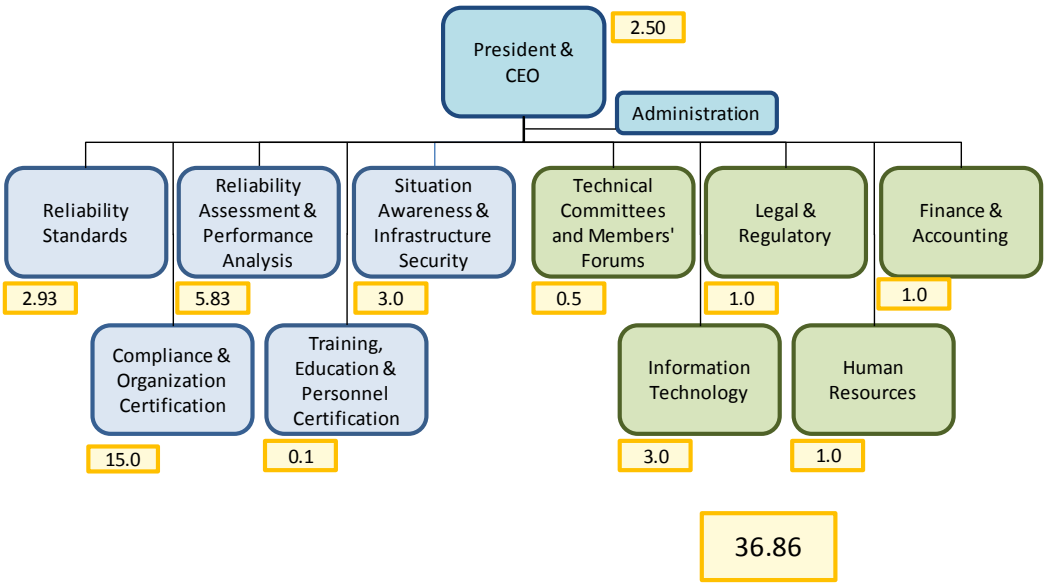
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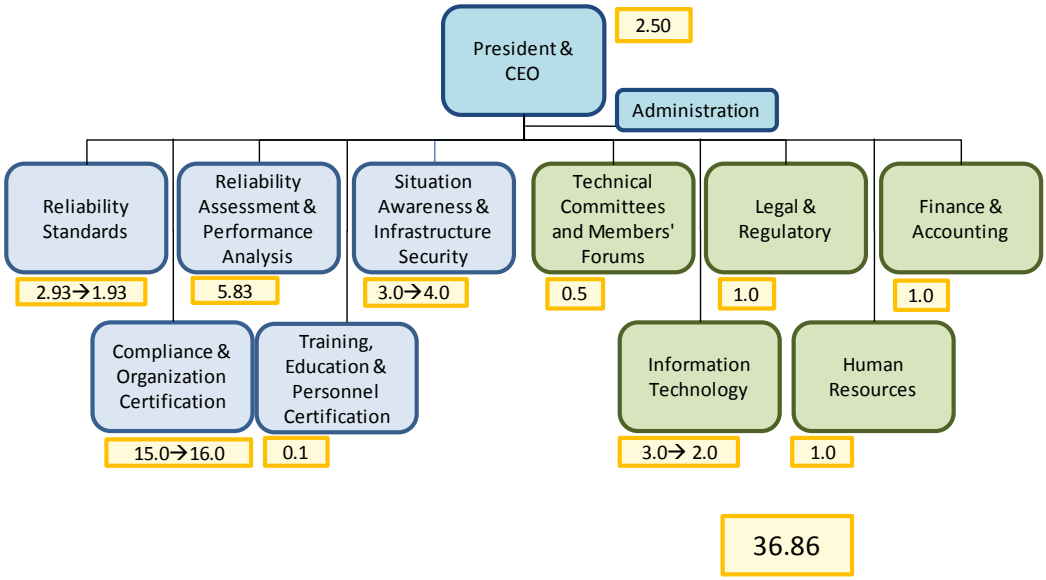
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Appendix A Staff Allocations

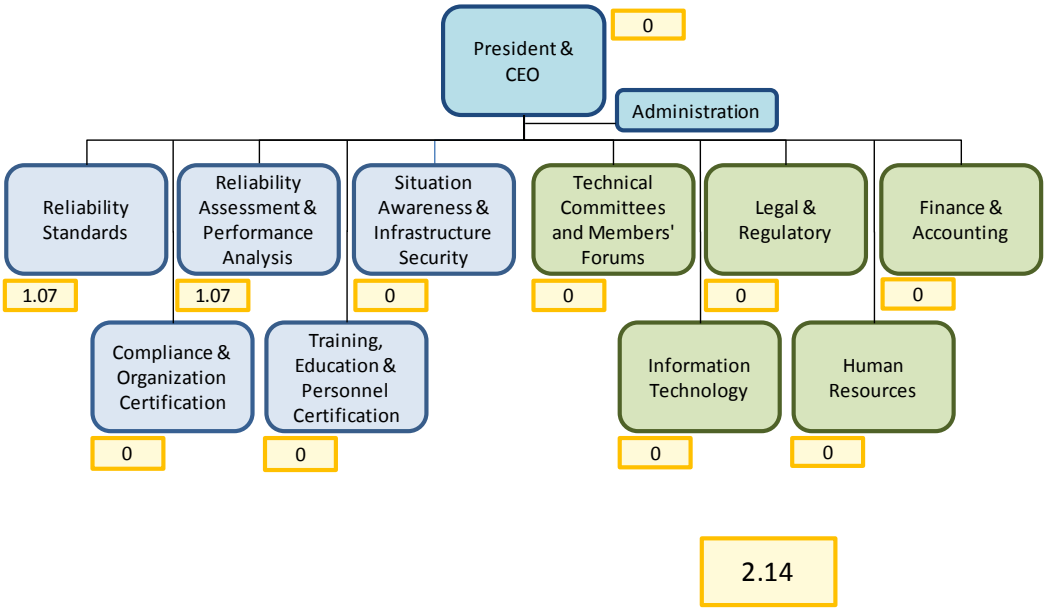
2016 Budget Staff Allocations - RE Division



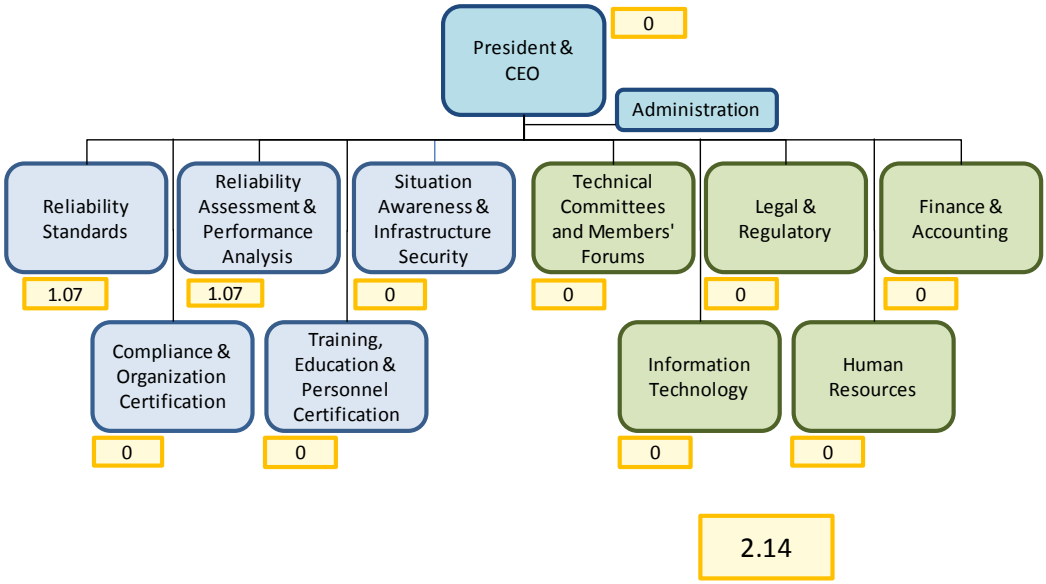
2017 Budget Staff Allocations - RE Division



2016 Budget Staff Allocations - CS Division



2017 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
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
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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