NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #23-5

December 7, 2023, 9:00 a.m. – 2:00 p.m. EDT **Hybrid Meeting**
Marriott New York Downtown
85 West Street At, Albany St,
New York, NY 10006
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)
Guest Code: 24333717429
Password: pvHRmxp@245 (78476971 from phone)
WebEx Link

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated March 8, 2023
NPCC Glossary of Terms, dated August 10, 2021

Introductions, Safety Message and Chair's Remarks

NPCC Antitrust Compliance Guidelines

Agenda Items:

1.0 Meeting Agenda

2.0 RSC Meeting Minutes (Approval Item)

3.0 Items Requiring RSC Discussion/Endorsement

- 3.1 FERC Activities
- 3.2 PRC-006-NPCC-3 Drafting Team List (Approval)
- 3.3 RSC Scope of Work (Approval)
- 3.4 RSC Work Plan (Approval)
- 3.5 Status of State and Provincial Outreach
- 3.6 RSC In-person meetings for 2024

4.0 NERC Reliability Standards

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

4.1 Currently Posted Projects

Project	Comment Period End Date	Ballot Period End Date
Project 2016-02 Modifications to CIP Standards Norm Dang from IESO @ 11:00 AM C	11/29/23 (F)	11/29/23 (A)
Project 2017-01 Modifications to BAL-003-1.1	6/1/23	6/1/23

David Lemmons from Greybeard Compliance Services @ 11:15 AM C	(F)	(A)
Project 2019-04 Modifications to PRC-005-6 Giuseppe Giannuzzi from HQ @ 11:30 AM C	7/24/23 (F)	7/24/23 (I)
Project 2020-06 Verifications of Models and Data for Generators Chris Larson from NERC @ 11:45 AM C	1/9/24 (F)	1/9/24 (A)
Project 2021-01 Modifications to MOD-025 and PRC-019 Chris Larson from NERC @ 11:45 AM C	6/8/23 (F)	6/8/23 (A)
Project 2021-02 Modifications to VAR-002 Ruida Shu	11/6/23 (F)	11/6/23 (A)
Project 2021-03 CIP-002 Transmission Owner Control Centers Russ Noble from Cowlitzpud @ 1:15 PM	11/9/23 (F)	11/9/23 (I)
Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination Kenny Lubbert @ 1:30 PM	11/30/23 (F)	11/30/23 (F)
Project 2021-08 Modifications to FAC-008 Ben Wu from NERC or Ruida Shu @ 2:00 PM	10/19/23 (F)	10/19/23 (I)
Project 2022-01 Reporting ACE Definition and Associated Terms Ruida Shu	10/30/23 (F)	10/30/23 (I)
Project 2022-02 Modifications to TPL-001 and MOD-032 Ben Wu from NERC or Ruida Shu @ 2:00 PM	11/20/23 (F)	11/20/23 (A)
Project 2022-03 Energy Assurance with Energy-Constrained Resources Brian Deckert	10/5/23 (I)	
Project 2023-01 EOP-004 IBR Event Reporting Chris Larson from NERC @ 11:45 AM C	9/11/23 (F)	9/11/23 (I)
Project 2023-03 Internal Network Security Monitoring (INSM) Ruida Shu	5/5/23 (F)	
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final		

4.2 Ballot History (Since last RSC Meeting)
4.3 Comment Form History (Since last RSC Meeting)

5.0 NPCC Non-Standards

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

5.1 Items for Discussion
- 5.1.1 Directory #1 Design and Operation of the BPS --- Jt. Planning/Ops Review
- 5.1.2 Incorporate Provisions of IEEE-2800 into Applicable NPCC Criteria

6.0 RSC Member Items of Interest

6.1 RSC Roster

7.0 Standards Activity Post NERC BOT Approval

(Since last RSC Meeting)

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

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

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

7.4 FERC Sunshine Act Meeting Notice

7.5 FERC Open Meeting Summaries

8.0 NERC Meetings

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

January 25th – Call	February 22th – Call	March 22nd – SPP
April 19th – Call	May 17th – Call	June 21st – Call
July 19th – MRO	August 23rd – Call	September 20th – NERC
October 18th – Call	November 15th – Call	December 13th – NERC

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

February 15-16 – Tuscan, AZ	May 3-4 – Hybrid Schedule	August 15-17 – Ottawa, ON
December TBD - Virtual		

9.0 NERC Items of Interest (Since last RSC Meeting)

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

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

9.2 Alerts
http://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx
There has been no new NERC Alerts released since the last RSC meeting.

9.3 NERC Reliability and Security Guidelines
https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx

9.4 NERC Rules of Procedure
https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx

9.5 FERC and NERC Encourage NAESB to Convene Gas-Electric Forum
FERC, NERC Encourage NAESB to Convene Gas-Electric Forum to Address Reliability Challenges

9.6 2023 State of Reliability Report
Report (nerc.com)

10.0 Future RSC Meetings and Conference Calls

10.1 RSC 2023 Meeting Dates

February 22nd - WebEx
May 24-25th – NYISO and WebEx
August 9-10th – WebEx
October 11-12th – Utility Services and WebEx
December 7th - General Meeting and WebEx

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 General Counsel and Corporate Secretary, Mr. Damase Hebert at (646) 737-2335 or dhebert@npcc.org.

NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #23-4

October 11, 2023, 10:00 a.m. – 3:00 p.m. EDT **Hybrid Meeting**
Utility Services Office
93 Pilgrim Park Rd, Suite A
Waterbury, VT 05676
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)
Guest Code: 24455030828
Password: KJmNpFY7@22 (55667397 from phone)
WebEx Link

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated March 8, 2023
NPCC Glossary of Terms, dated August 10, 2021

Attendance:

	Name	Organization	Sector(s)	Status
1.	Gerry Dunbar	Northeast Power Coordinating Council		In-person
2.	Ruida Shu	Northeast Power Coordinating Council		In-person
3.	Brian Deckert	Northeast Power Coordinating Council		In-person
4.	Kal Ayoub	FERC	Guest	WebEx
5.	Alain Mukama	Hydro One	1	WebEx
6.	Bendong Sun	Bruce Power LP	4	WebEx
7.	Carole Laprise		Guest	WebEx
8.	Ceila-Nour Mahrour-Venturelli		Guest	WebEx
9.	Chantal Mazza	Hydro Quebec	2	In-person
10.	Chris O'Brien	Eversource	1	WebEx
11.	Cindy Robert	Hydro Quebec	Guest	WebEx
12.	Constantin Chitescu	OPG	4	WebEx
13.	Damian Interrante	Central Hudson Gas & Electric	1	WebEx
14.	Daniel Valle		Guest	WebEx
15.	Dave Kwan	OPG	4	WebEx
16.	Doug Preston	OPG	Guest	WebEx
17.	Erin Wilson	NB Power	1	WebEx
18.	Gabriel Dion	Hydro Quebec	Guest	WebEx

19.	Harish Vijay Kumar	IESO	2	WebEx
20.	Herb Schrayshuen	Power Advisors, LLC	Guest	WebEx
21.	Jason Chandler	Con Edison	5	WebEx
22.	Jeffrey Streifling	NP Power	1	WebEx
23.	Joel Charlebois	AESI	7	WebEx
24.	Jim Grant	NYISO	2	WebEx
25.	Junji Yamaguchi	Hydro Quebec	1	WebEx
26.	Kurtis Chong	IESO	2	WebEx
27.	Libin Varghese	NYPA	4	WebEx
28.	Lodie White	FERC	Guest	WebEx
29.	Michael Courchesne	ISO-NE	2	WebEx
30.	Michael Jones	National Grid	3	In-person
31.	Michael Ridolfino	CHG&E	1	WebEx
32.	Michele Shafer	The United Illuminating Company	1	WebEx
33.	Michele Tondao	The United Illuminating Company	1	WebEx
34.	Mike Foley	Con Edison	4	WebEx
35.	Randy Buswell	VELCO	1	In-person
36.	Sandhya Vaidya	Hydro Quebec	Guest	WebEx
37.	Siobhan Keane-Revie	Orange and Rockland	3	WebEx
38.	Tobi Ajayi	OPG	Guest	WebEx
39.	Tracy MacNicoll	Utility Services	5	In-person
40.	Vijay Puran	NY State Department of Public Service	6	WebEx
41.	Latrice Harkness	NERC	Guest	WebEx
42.	Norm Dang	IESO	Guest	WebEx
43.	David Lemmons	Greybeard Compliance	Guest	WebEx
44.	Joe Gatten	Xcel Energy	Guest	WebEx
45.	Chris Larson	NERC	Guest	WebEx
46.	Adrain Raducea	DTE Energy	Guest	WebEx
47.	Russ Noble	Cowlitzpud	Guest	WebEx
48.	Ben Wu	NERC	Guest	WebEx
49.	Alexandre Bertrand	Hydro Quebec	Guest	WebEx
50.	Hugo Perez	NERC	Guest	WebEx
51.	Lauren Perotti	NERC	Guest	WebEx
52.	Rich Machado	NYPA	Guest	WebEx
53.	Sarah Crawford	NERC	Guest	WebEx
54.	Yves Drolet	Hydro Quebec	Guest	WebEx

Introductions, Safety Message and Chair's Remarks
Gerry Dunbar provided remarks on standards activities.

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

Agenda Items:

1.0 Meeting Agenda

2.0 RSC Meeting Minutes (Approval Item)

Approval of the October 11, 2023, RSC meeting minutes – no changes necessary for the draft RSC meeting minutes that were provided in the agenda package.
Michael Jones made the motion to approve the RSC meeting minutes.
Jeffrey Streifling seconded the motion.
The October 11, 2023, RSC meeting minutes is approved.

3.0 Items Requiring RSC Discussion/Endorsement

3.1 FERC Activities

Kal updated the RSC members on FERC and NERC Joint Inquiry, FERC Orders, and Technical Conferences.

- Key findings from FERC/NERC joint inquiry into winter storm Elliot
  - 5th time in 11 years that extreme cold weather led to significant generation losses.
  - Unprecedented unplanned generation loss
    - 90,000 MW
    - Nearly 80% generating units failed to perform at rated temperatures.
    - Grid operators had to shed load to maintain reliability.
    - Natural gas pipelines pressures dropped because of freeze related production.
    - Con-Ed even had to declare an emergency and use its own liquefied gas facility to maintain service, this was a major find.
  - There were 11 recommendations for action.
    - It was recommended to read the report but noted that Congress stated that a plan should be figured out within 3 years.
  - Commissioner recommended that someone, it doesn't have to be FERC, could/should take the lead on overseeing natural gas production and distribution during extreme weather conditions.
- Joint Technical Physical Security of the BPS
  - 55,000 substations in this country, which is more than many fast-food company locations combined.

- Annual Reliability Technical Conference on November 9th, 2023
- Kal posted a link to the presentation, see below.
    - https://www.ferc.gov/news-events/news/elliott-report-complete-electricity-standards-implement-gas-reliability-rules

3.2 PRC-006-NPCC-3 Status

Ruida Shu provided a status update on PRC-006-NPCC-3. NPCC is currently solicitating drafting team members for PRC-006-NPCC-3, and the solicitation period will conclude on November 6, 2023. The goal is to compile the list of qualified candidates, review and approve them at the December 7, 2023, RSC meeting.

- First meeting of the SDT will probably be early January 2024

3.3 RSC Scope of Work and Work Plan

Michael Jones, Chantal Mazza, and Jeffrey Streifling volunteered to serve on the small group to work on updating the RSC Scope of Work and Work Plan.

3.4 RSC Vice Chair Election

Mike Jones re-election 2024-2025, extend Chantal Mazza existing term from 2024 to 2025.
Constantin made the motion to re-elect Mike Jones and extend Chantal Mazza's term.
Tracy MacNicoll seconded the motion.
Mike Jones is re-elected to be the RSC Vice-Chair for 2024-2025 and Chantal Mazza's term is extended from 2024 to 2025.

3.5 NPCC Corporate Goal II-2 Incorporate Provisions of IEEE-2800 into NPCC Criteria

White paper was developed that considered how the issue of IBRs should be considered in NPCC Directories and Criteria.
Presented to RCC in 2022, push back was that it did not incorporate any of IEEE 2800 into NPCC Directories.
Approved with the understanding that there would be an effort to incorporate IEEE-2800 into NPCC directories and criteria by September of 2023 (consultant was hired), which was done.
There were comments from at least 2 organizations, so those will have to be reconciled.
Goal is to present final document to RCC in December
This is meant to be a guidance document.

3.6 NERC Project Updates by Latrice Harkness (12:30 PM)

Latrice Harkness provided an update on NERC project categorizations, Projects are prioritized into High, Medium, and Low priorities. The goal is to

focus on High priority projects for 2024. Medium and Low priority projects will be worked on in 2025.

- She highlighted the importance of people participating in comment and ballot period.
    - Commented that almost 80% of recent standards don't pass on the first posting.
- Follow up question from Gerry Dunbar regarding NERC definition of IBR, she stated that 2020-06 has been informally posted for comment, including the definition of IBR.

4.0 NERC Reliability Standards

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

4.1 Currently Posted Projects

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Project 2017-01 Modifications to BAL-003-1.1 David Lemmons from Greybeard Compliance Services @ 1:15 PM	6/1/23 (F)	6/1/23 (A)
Project 2019-04 Modifications to PRC-005-6 Giuseppe Giannuzzi from HQ @ 1:30 PM NC	7/24/23 (F)	7/24/23 (I)
Project 2020-04 Modifications to CIP-012 Joe Gatten from Xcel Energy @ 2:30 PM	11/2/23 (F)	11/2/23 (A)
Project 2020-06 Verifications of Models and Data for Generators Chris Larson from NERC @ 1:45 PM	10/24/23 (F)	7/21/23 (A)
Project 2021-01 Modifications to MOD-025 and PRC-019 Chris Larson from NERC @ 1:45 PM	6/8/23 (F)	6/8/23 (A)
Project 2021-02 Modifications to VAR-002 Adrian Raducea from DTE Energy and David Daniels from AEP @ 2:00 PM	11/6/23 (F)	11/6/23 (A)
Project 2021-03 CIP-002 Transmission Owner Control Centers Russ Noble from Cowlitzpud @ 2:45 PM	11/9/23 (F)	11/9/23 (I)
Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination NERC Legal and HQ SME @ 1:00 PM	9/16/23 (F)	10/6/23 (F)
Project 2021-08 Modifications to FAC-008 Ben Wu from NERC @ 3:00 PM	10/19/23 (F)	10/19/23 (I)
Project 2022-01 Reporting ACE Definition and Associated Terms Ruida Shu	10/30/23 (F)	10/30/23 (I)
Project 2022-02 Modifications to TPL-001 and MOD-032 Ben Wu from NERC @ 3:00 PM	7/14/23 (F)	7/14/23 (I)
Project 2023-01 EOP-004 IBR Event Reporting Chris Larson from NERC @ 1:45 PM	9/11/23 (F)	9/11/23 (I)
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period		

Ballots: (I) – Initial; (A) – Additional; (F) – Final

- Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination:
  - EOP-11 and TOP-2 just passed final ballot and will go to the Board of Trustees for approval (Oct 24th). NERC is working on the FERC filing to be submitted upon Board of Trustees approval.
  - Modifications to EOP-11 clarify how critical natural gas infrastructure loads are to be identified and clean up on vernacular regarding automatic and manual load shedding related to UFLS and UVLS, and to remove Remedial Action Schemes from applicability.
  - Modifications to TOP-2 clarify study parameters and applicability of the BA Operating Process for Extreme Cold Weather periods.
  - Drafting team is finalizing edits to EOP-12 and accompanying documents.
  - Formal comment period to begin in early November.
  - Edits will address all outstanding comments from the previous Phase 2 posting, and address FERC directives from the February 2023 Order
  - The SDT will be presenting a cleaner version of EOP-012 based on industry comments at the end of the month.
  - FERC deadline for EOP-12 is February 2024

- Project 2020-04 Modifications to CIP-012
  - Request clarification of “availability” vs “loss of data.”
  - Loss of data is out of the scope for this project (CIP-012).
  - Since it is a CIP standard, the goal is to ensure the link between the control center instead of preventing the loss of data.

- Project 2019-04 Modifications to PRC-005-6 update.
  - In the process of responding to comments
  - Planning on meeting next week, or the week after, to review the responses.
  - Failed balloting last time at 35%
  - Complication is that the term ‘System Protections’ are referenced so many standards, that the context in which they are used in each standard must be considered as they move forward.

- Project 2022-01 Reporting ACE Definition and Associated Terms
  - Open for industry comments and ballot
  - This was already approved via ballot, but the SDT made a substantive change to a definition, the definition of ACE, which required another ballot and comment period.
  - So far, no new comments received, due by October 30th.

- Project 2016-02 Modifications to CIP Standards
  - Norm Dang from IESO gave the update.
  - Ballot 5 closes on November 16th
    - Webinar on October 19th on it
  - CIP-005 barely failed ballot 4, R1 & R2 have been clarified, hopefully passes next time.
  - CIP-010 failed ballot 4 badly, R1 & R2 have been updated and clarified.
  - CIP-007 barely passed ballot 4, R1.3 has been changed for clarification.
  - CIP-003, passed ballot 4, but substantial changes made to low impact appendices, mirrored changed to TCAs from CIP-010
  - CIP-04 b passed ballot for, but issues found in R5.1 and needs to be updated.

- Project 2017-01 Modifications to BAL-003-1.1
  - David Lemons update, continuing to address comments from the last ballot, discussing issues with NERC legal,
  - They were notified that this project will be moved into the lower priority bucket, so they do not expect it to be posted any time soon.

- Project 2020-06 Verifications of Models and Data for Generators
  - This is where the IBR definition will live.
  - 2 proposed definitions, during informal comment period
    - Closes October 24th
    - MOD 26 and MOD 27 were merged, they each have a requirement (R2 & R3) for synchronous.
  - Part of the problem stands from the ambiguity of how the standard describes IBR Unit. The new term is Power Electronic Devise Resource, not sure if it's from IEEE 1547 or 2800
  - Only 13 more days to submit comments.

- Project 2021-01 Modifications to MOD-025 and PRC-019
  - Comment period ended middle of June.
  - MOD-025 is looking to incorporate their revisions and comments and starting with a fresh revision rather than their existing redline.
  - PRC-019, still working on industry outreach to resolve some comments they received, but they use IBR in that standard, so they are also relying/dependent on the definitions being finalized.
  - No set date for next posting, as it is now considered low priority.

- Project 2021-02 Modifications to VAR-002
  - It is in the 45-day commenting period, ending Nov 6th.
  - Balloting will open in late October and will also close on Nov 6th.

  - Transmission Operator is not currently applicable.
  - See Project 2021-02 Modifications to VAR-002-4.1 (nerc.com)
    - See latest version.
  - They have attempting to align with the NERC Glossary of Terms

- Project 2021-03 CIP-002 Transmission Owner Control Centers
  - Approved for initial posting.
  - There are 2 standard drafting teams working on the standards.
    - This version is CIP-002-Y
    - Goal is to merge them into a single posting in the future.
    - Balloting will close November 9th.
  - Some terms were modified form the responses to the original comment period.
    - TOs seem to have various definitions for 'control' 'data center' 'control center.'
    - Effort was made to clarify the misconceptions and differences between these definitions.
    - RC/BAs don't control the BES, but they do monitor and perform reliability tasks.
    - TOP DOES have the ability to monitor and control.
    - Transmission Owners and Generation personnel have the ability to control but may not have the authority.
    - See up to date standard for more detail on various terms and their clarified definitions.
    - An exclusion was made for distributors where part of their system that has less than 300kV, it can be removed from the aggregate value (see 2.12), as long as the net export from the local system does not exceed 75MW during non-Energy Emergency Alert)
    - Updated definition of Control Center will be applied as a Glossary Term

- Project 2021-08 Modifications to FAC-008
  - Cannot talk about it because it is currently out for ballot.

- Project 2022-02 Modifications to TPL-001 and MOD-032
  - MOD-032 posted for second ballot, started on October 6th, until November 20th
    - Not a lot of changes made to requirements, just a couple of title corrections.
    - Changes made to clarify what the data recording requirements on attachment 1.
    - MOD-032 Also modified DR for clarification of DER definition, in the standard only, not to the NERC Glossary of Terms

- They did post the technical rationale.
- TPL-001 will be worked on in 2024.

- Project 2023-01 EOP-004 IBR Event Reporting
  - This is a medium priority project, attempting to add a reporting threshold specifically to the BA.
  - Comment period ended September 19th, currently working on outreach.
    - A lot of the GOs thought the 500MW threshold would lead to excessive reporting, but they did not understand that the threshold was meant to apply only to the BA.

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

4.3 Comment Form History (Since last RSC Meeting)
Ruida Shu reviewed the comment form history document in the meeting.

5.0 NPCC Non-Standards

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

5.1 Items for Discussion

5.1.1 Directory #1 Design and Operation of the BPS --- Jt. Planning/Ops Review
Posted for comment through November 13, 2023.The Joint Working Group will convene to consider Member comments and revise the draft as appropriate.

6.0 RSC Member Items of Interest

6.1 RSC Roster
There were some minor updates, including the IESO rep and Utility Services. Roster to be updated before next meeting (already accomplished)

7.0 Standards Activity Post NERC BOT Approval

(Since last RSC Meeting)

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9.5 FERC and NERC Encourage NAESB to Convene Gas-Electric Forum
FERC, NERC Encourage NAESB to Convene Gas-Electric Forum to Address Reliability Challenges

9.6 2023 State of Reliability Report
Report (nerc.com)

10.0 Future RSC Meetings and Conference Calls

10.1 RSC 2023 Meeting Dates

February 22nd - WebEx
May 24-25th – NYISO and WebEx
August 9-10th – WebEx
October 11-12th – Utility Services and WebEx
December 7th - General Meeting and WebEx

The meeting is adjourned at 3:04 PM.

Northeast Power Coordinating Council, Inc. (NPCC)

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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.

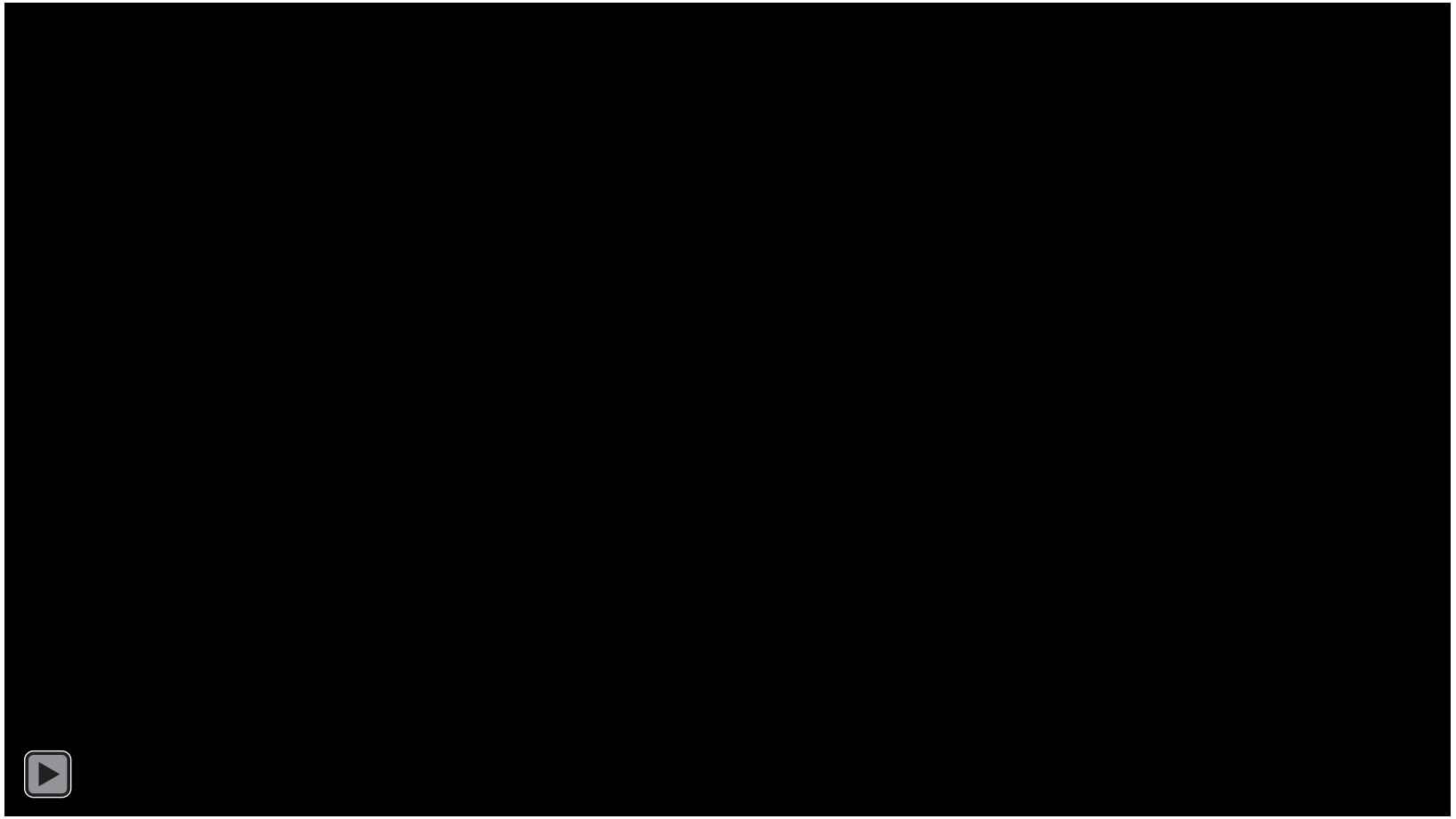
Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's General Counsel and Corporate Secretary, Mr. Damase Hebert at (646) 737-2335 or dhebert@npcc.org.

2023 Reliability Activities

Kal Ayoub – Chairman's Critical Infrastructure and Resilience Advisor

December 7, 2023

What are Chairman Phillips' Priorities?



Chairman Phillips Priorities

- Chairman's Priorities – Reliability, Transmission Reform, Environmental Justice
- Chairman's Reliability Priorities – **Reliability is Job #1**
    1. Protecting the grid from cyber and physical attacks;
    2. Preparing for extreme weather; and
    3. Ensuring reliability as the resource mix changes.
- Transmission Reform:
    - Final Rule on Interconnection Procedures
- Environmental Justice:
    - Roundtable and Equity Action Plan
- Technical Conferences
    - Physical Security Tech Conference
    - Annual Reliability Tech Conference

Chairman Reliability Priority:

Protecting the Grid from Cyberattacks

Internal Network Security Monitoring

- Final Rule on Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems, issued January 19, 2023 (Order No. 887, Docket No. RM22-3-000.
  - Final Rule directs NERC to develop and submit within 15 months of the effective date new or modified Reliability Standards that require internal network security monitoring for all high impact bulk electric system BES Cyber Systems with and without external routable connectivity and medium impact BES Cyber Systems with external routable connectivity.
  - Final Rule directs NERC to perform a study of all low impact BES Cyber Systems with and without external routable connectivity.

"The nature of cyber security threats to our nation's grid require constant monitoring and vigilance. One year after we proposed this rule at my first meeting as a Commissioner, we are finalizing this rule in my first meeting as Chairman, and taking a major step to better secure the reliability of our nation's bulk power system."

Willie L. Phillips, FERC Chairman

Chairman Reliability Priority:

Protecting the Grid from Cyberattacks

Supply Chain Revisions for Low-Impact Cyber Systems

> "The vast majority of BES assets today are considered low-impact and that number is only expected to grow. To not protect these BES assets against one of the most frequent attack scenarios – supply chain – would be a big mistake"
>
> Willie L. Phillips, FERC Chairman

- On March 16, 2023, the Commission approved Reliability Standard CIP-003-9 (Cyber Security – Security Management Controls). Docket No. RD23-3-000.
  - Requires entities with bulk electric system facilities whose assets are designated low impact to have methods for determining and disabling vendor remote access.
  - Expands existing security controls to provide greater visibility into electronic communication between low impact bulk electric system cyber systems and vendors.
  - Will allow detection and the ability to disable vendor remote access in the event of a known or suspected malicious communication.
- CIP-003-9 becomes effective on April 1, 2026

Chairman Reliability Priority:

Protecting the Grid from Cyberattacks

Incentive Rate Treatment for Cybersecurity Investments

- Issued April 21, 2023: Order No. 893, a final rule providing incentive-based rate treatment for utilities making certain voluntary cybersecurity investments in Docket No. RM22-19
  - Establishes incentive-based rate treatments to encourage utilities to invest in advanced cybersecurity technology and participate in cybersecurity threat information sharing programs to benefit consumers.
  - Expenditures must materially improve a utility's cybersecurity posture.
  - Cybersecurity investments eligible for incentives include:
    1. Those on the pre-qualified list; and
    2. Those determined to be eligible by the Commission on a case by case basis, including early compliance with cybersecurity Reliability Standards

"We must continue to build upon the mandatory framework of our cybersecurity reliability standards with efforts such as this to encourage utilities to proactively make additional cybersecurity investments in their systems."

Willie L. Phillips, FERC Chairman

Chairman Reliability Priority:

Protecting the Grid from Physical Attacks

- On April 20, 2023, Jim Robb, President and CEO of NERC, presented NERC's evaluation of the Physical Security Reliability Standard in light of recent physical attacks on the BPS
- At Chairman's direction, a Joint Technical Conference Regarding Physical Security of the Bulk-Power System was held on August 10, 2023, in Docket RD23-2 hosted by NERC
  - Recommended by NERC Physical Security Report
  - Part 1: Effectiveness of Reliability Standard CIP-014-3
  - Part 2: Solutions Beyond CIP-014-3

"We have talked about this issue of physical security many times. There is no greater priority for me and for this Commission than making sure that we protect the security of our electric grid"

Willie L. Phillips, FERC Chairman

Chairman Reliability Priority:

Preparing for Extreme Weather

FERC Approved and Directed Changes to Cold Weather Standards

- Order approving EOP-011-3 (Emergency Operations) and EOP-012-1 (Extreme Cold Weather Preparedness and Operations) in Docket No. RD23-1, 2/16/2023
  - Proposed standards include winterization requirements for GOs
  - Commission directed changes to EOP-012-1
- Revised standard and data collection plan is due February 16, 2024.

"These new standards will help to prepare our nation's grid and our grid operators so they can provide power to consumers in the face of extreme weather.

I am pleased that NERC and its regional entities acted swiftly to propose these reliability standards so that my fellow Commissioners and I could move decisively and vote today to ensure the reliability and resilience of the bulk power system."

Willie L. Phillips, FERC Chairman

Chairman Reliability Priority:
Preparing for Extreme Weather

FERC Approved Extreme Weather Final Rules

- Order No. 896, Transmission System Planning Performance Requirements for Extreme Weather. Docket No. RM22-10 issued June 15, 2023.
  - NERC must submit the new or revised reliability standards by December 23, 2024.
- Order No. 897, One Time Reports on Extreme Weather Vulnerability Assessments. Docket Nos. RM22-16 and AD21-13 issued June 15, 2023.
  - Directs transmission providers to file one-time informational reports describing how they conduct extreme weather vulnerability assessments, if at all
  - One-time informational report is due by October 25, 2023.

"Make no mistake: Reliability at FERC is Job No. 1 - For the first time, reliability standards will require planning for extreme heat and cold weather. NERC will develop the standards, and once we approve them transmission owners and operators will identify the elements of their systems that are vulnerable to extreme heat and cold and develop solutions to address those vulnerabilities."

Willie L. Phillips, FERC Chairman

Chairman Reliability Priority:

Preparing for Extreme Weather

Final Report on FERC-NERC Joint Inquiry into Winter Storm Elliott

- On **November 7,** FERC, NERC and RE Joint Team released the final report on Winter Storm Elliott, the Christmas 2022 storm that contributed to power outages for millions of electricity customers in the Eastern half of the country.
  - Unprecedented unplanned generating unit losses, with nearly 90,000 megawatts out at the same time.
  - ➢ Nearly 80 percent of the generating units failed to perform at temperatures above their own documented minimum operating temperatures.
  - ➢ Several electric grid operators had to shed firm load to maintain system reliability.
  - ➢ Natural gas pipeline pressures dropped largely because of freeze-related production as well as other natural gas infrastructure freeze- and equipment-related problems.
  - ➢ **Consolidated Edison Inc faced reliability-threatening low pressures on its delivery pipelines, forcing it to declare an emergency and use its own liquefied natural gas facility to maintain service.**

"The FERC and NERC teams analyzed what happened, what went wrong, and the steps utilities, grid operators and stakeholders must take to avoid this in the future. I want everyone to take time during this Reliability Week to read this report and begin implementing these recommendations, particularly those addressing the interdependence of gas and electricity. The report highlights what I've called for before: **Someone must have authority to establish and enforce gas reliability standards**."

Willie L. Phillips, FERC Chairman

Chairman Reliability Priority: Ensuring Reliability as the Resource Mix Changes

FERC Approved NERC's IBR Registration Work Plan

- As directed by FERC,NERC filed an IBR Registration Work Plan that sets forth NERC's three-phased approach to identify and register certain unregistered IBRs
- On May 18, 2023, the Commission approved NERC's IBR Registration Work Plan in Docket No. RD22-4-001.
  - ➢ First quarterly Work Plan update was due on August 14, 2023.

"I believe in an all-of-the-above approach…whatever resources are needed to keep our grid reliable…we have to make sure they are available."

Willie L. Phillips, FERC Chairman

Chairman Reliability Priority: Ensuring Reliability as the Resource Mix Changes

FERC Issued IBR Final Rule

- On October 19, FERC issued a final rule directing NERC to develop new or modified reliability standards that address IBR data sharing, model validation, planning and operational studies, and performance requirements.
- NERC must file the new or revised standards in tranches, with each tranche due no later than November 4 of each of the next three years. NERC also has 90 days to submit to the Commission an informational filing that includes a detailed, comprehensive standards development and implementation plan.

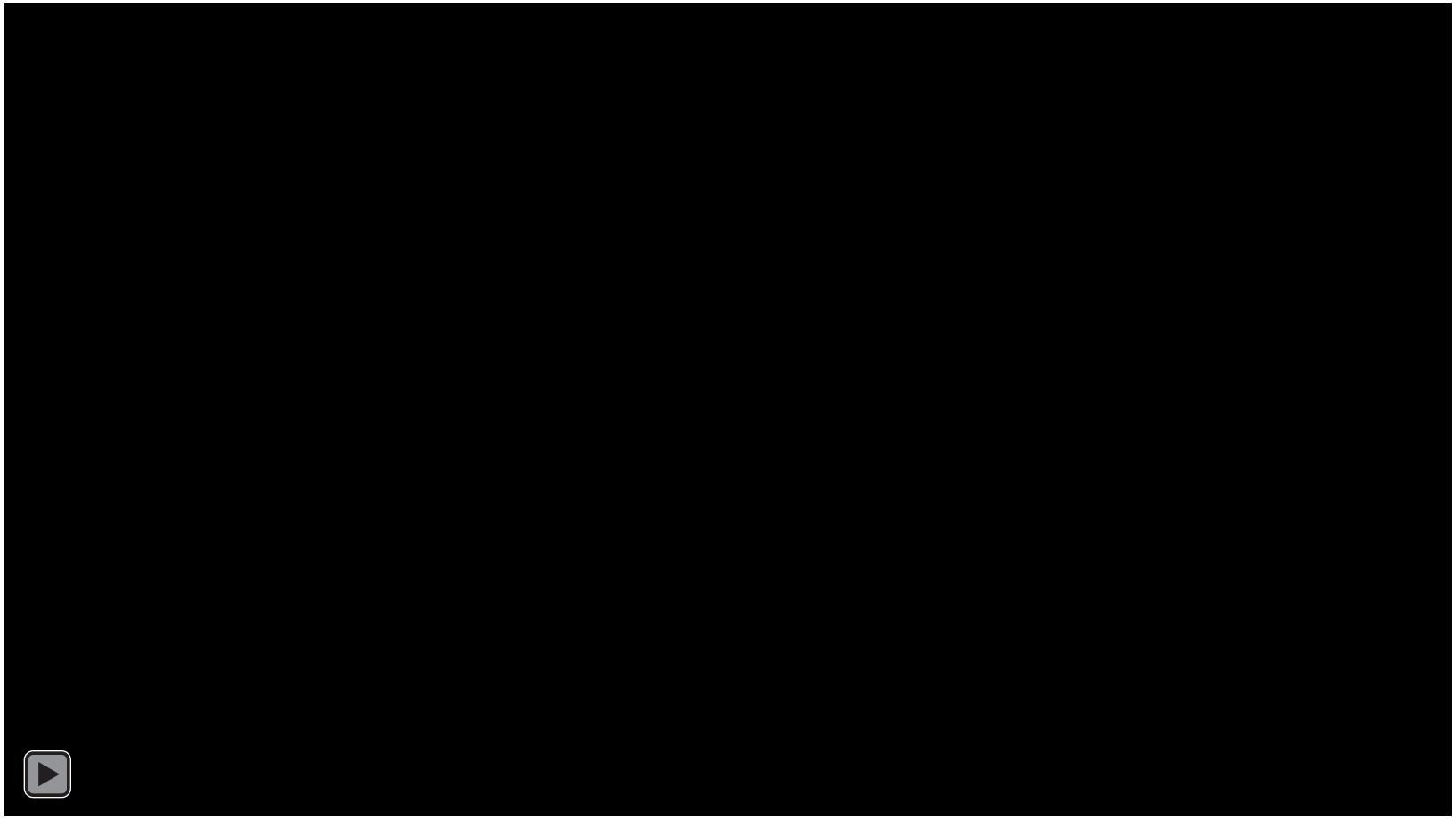
> "These standards will help us solve one the biggest problems we're facing, as we make the transition to clean energy resources,. We need to make sure that these promising new technologies can enhance, not weaken, reliability of the grid. We mean it when we say that at FERC, reliability is, and remains, Job No. 1."
>
> Willie L. Phillips, FERC Chairman

2023-2024 Winter Energy Market and Electric Reliability Assessment

(November 16, 2023)

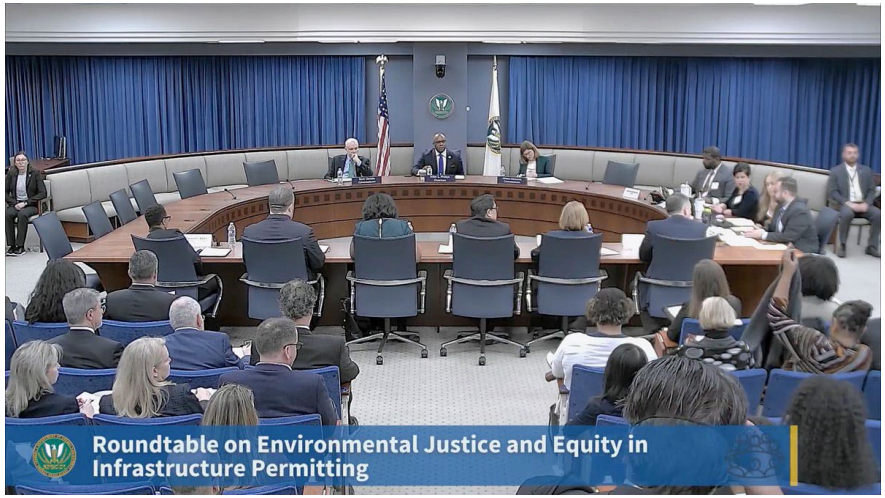
- Mild temperatures likely this winter for northern half of country.
- Natural gas futures prices decrease and natural gas demand to grow slightly.
- The rate of resource additions expected to increase year-over-year.
- New transmission capacity mostly for aging infrastructure, load growth, reliability.
- Adequate resources in all regions for normal winter.
- Possible reliability challenges for some regions under certain conditions.
- NERC highlights wide area cold events threaten reliability.
- NERC recommends cold weather preparations, fuel surveys, anticipating load forecasting errors in extreme cold, and support from state regulators and policy makers.

Chairman Priority – Transmission Reform, Order 2023
"We are just getting started!"



Chairman Priority – Environmental Justice

- The Commission held a Commissioner-led Roundtable on Environmental Justice and Equity on March 29, 2023.
- The Commission's two-year Equity Action Plan aims to reduce barriers to meaningful participation by underserved communities.
- Conrad Bolson has been appointed Senior Counsel for Environmental Justice and Equality and will lead these efforts.



"I've said this before, and I'll say it again. It is not a talking point for me, it is personal when I talk about environmental justice".

Willie L. Phillips, FERC Chairman

Technical Conferences

- Joint Technical Conference Regarding Physical Security of the Bulk-Power System - August 10, 2023.

- Annual Reliability Technical Conference - November 9, 2023.

Questions?

DRAFTING TEAM--RSAR PRC-006-NPCC-02

	Task Force on System Protection	
1	John Babu—RSAR Requester	Eversource Energy
2	Paul DiFilippo	Ironhouse
3	Craig Marien	Eversource Energy
4	Thomas Muratore	PSEG LI
	Self-Nominations	
1	Jeffrey Scott Streifling	NB Power
2	Chris Boucher	Taunton Municipal Lighting Plant
3	Michael Ridolfino	Central Hudson Gas & Electric
4	Gabriel Dion Marcotte	Hydro Quebec
5	Laurie Martuscello	National Grid
6	Constantin Chitescu	Ontario Power Generation
7	Patrick Palompo—NPCC Auditor	NPCC
8	Ruida Shu—DT Secretary	NPCC

NPCC Board of Director Meeting
January xx,2024
Draft for Approval, Agenda Item XX

2024 Scope of Work for the Regional Standards Committee

The NPCC Regional Standards Committee ("RSC") aligns its activities with the NPCC and NERC Strategic Plans and is charged with:

(a) Managing and maintaining the NPCC Regional Standards Development Process in accordance with the Regional Standard Processes Manual (RSPM).
(b) Managing and maintaining the process for NPCC Criteria and Directory Development.
(c) Providing consolidated NPCC Regional review and comments to existing and proposed NERC Standards in accordance with the NERC Standard Processes Manual (SPM).
(d) Reviewing FERC Orders and Notice of Proposed Rulemakings ("NOPRs") related to Reliability Standards.
(e) Reviewing any new and revised NERC Reliability Standard Audit Worksheet ("RSAW"), as may be requested by the NPCC Compliance Committee ("CC") and submit comments to NERC as appropriate.
(f) Providing consolidated NPCC Regional review and comments to the existing and proposed NERC Standards Development Processes Manual and to the NERC Rules of Procedure (RoP) as they relate to Standards Development.
(g) Determining the need for, and development of, NERC and Regional Standards, Variances to NERC Standards, modifications to NPCC Criteria and Directories, and/or interpretations and clarifications thereof.
(h) In coordination with the NPCC CC, address issues identified through the NPCC Regional Feedback Mechanism to continually improve standards and NERC documents which includes Guidelines and other technical material.
(i) In coordination with the Reliability Coordinating Committee ("RCC"), address issues identified through the "Distributed Energy Resource (DER)/Variable Energy Resources (VER) BES Impact Reporting Form", conduct, maintain, and further develop the process as necessary.
(j) Providing a forum for information with the goal of sharing best practices on reliability issues associated with industry standards, guidance and/or regulations. In addition, forum topics may include emerging issues such as building electrification, electric vehicle charging, and transmission integration.
(k) After receiving comments from NPCC stakeholders on relevant NERC documents, the RSC will be responsible for coordinating consensus and the NPCC Standards Program Area Staff will submit Regional comments to NERC.

The RSC is an open and balanced committee inclusive of all stakeholders that provide for, or are materially impacted by, the reliability of the NERC Bulk Electric System and the NPCC Bulk Power System as defined by Criteria A-10. The RSC meetings are open to all stakeholders who want to participate, and meeting materials will be publicly posted on the NPCC

Website.

Decisions of the NPCC RSC will be adopted under a sector-based voting structure as described in the NPCC Amended and Restated Bylaws.

The RSC will coordinate its work through the NPCC Standards Program Area Staff which will submit standards related comments pursuant to the NERC SPM and the NERC RoP.

The RSC will be chaired and assisted by NPCC Standards Program Area Staff along with Co-Vice chairs elected by the RSC from among the members of the RSC at the time the vote is taken. Chair and Co-Vice Chair appointments will be submitted to the NPCC Board of Directors for final approval. The Co-Vice chairs will serve a term of two years. The Vice-Chair term may be extended through a motion and subsequent vote by the committee.

Members of the RSC will be nominated by their respective companies. NPCC RSC leadership (RSC Chairperson and Co-Vice Chairpersons) will review and consider the approval of all nominations to the RSC. The nominations will include contact information and qualifications to serve on the committee. Each of the NPCC Sectors as defined in the NPCC Amended and Restated Bylaws will be open to representation on the RSC in accordance with the NPCC Amended and Restated Bylaws.

Subcommittees and ad hoc Working Groups will be formed upon request of the RSC by NPCC Standards Program Area Staff. All associated scopes or charters developed, will be approved by the RSC.

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

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

RSC Members should consider not only what is best for their company but also what is in the best interest of the broader industry and NERC Bulk Electric System and NPCC Bulk Power System reliability.

RSC Members should make every effort to attend scheduled meetings and when not available are required to identify and provide a qualified proxy participant. RSC business cannot be conducted in the absence of a quorum, and it is essential that each RSC Member make a commitment to be present. A determination to recommend removal of an RSC member shall be considered by the NPCC RSC leadership if that member is excessively absent and provides no proxy for regularly scheduled meetings. In this case the NPCC Member Representative will be notified of the intent to remove the member from the Roster prior to the formal removal of that member.

A. NPCC Regional Standards Process Responsibilities

The RSC is responsible for managing the Regional standards process for the development of ERO Regional Standards, Violation Risk Factors ("VRFs"), Violation Severity Levels ("VSLs"),

definitions, Regional Interconnection-wide variances (e.g., Quebec's UFLS), interpretations and clarifications in accordance with the NPCC Regional Standard Processes Manual and the NPCC Amended and Restated Bylaws pertaining to quorum and voting rules. The RSC is responsible for promoting and pursuing the quality of all standards-related materials.

The RSC will be available to advise the NPCC BOD on NERC standards related matters.

B. NPCC Criteria and Directory Process Responsibilities

The RSC provides oversight for the development of NPCC Criteria and Directories within each document. The RSC will provide guidance to all NPCC Committees, Task Forces and Working Groups regarding NPCC documents including Criteria, Directories, Procedures, Guidelines, and the Cost Effectiveness Procedure. The RSC will also maintain and oversee the Directory Development and Revision Manual and related processes. Coordinate any NPCC Regional Criteria and Directory activity with NERC Standards development activity to avoid duplication. DER/VER BES Impact reporting activities will be coordinated with the Reliability Coordinating Committee ("RCC").

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

C. NERC Reliability Standards Responsibilities

The RSC will:

- Provide a forum for NPCC review, coordination, and submission of regional comments to existing or proposed NERC Reliability Standards when posted for NERC "Open Process Review."
- Provide a forum for NPCC to participate, solicit and provide Regional comments on Standard Authorization Requests ("SARs") and their respective Reliability Standards in accordance with the NERC SPM.
- Provide a forum for NPCC to participate in and be kept aware of emerging risks from the NERC Reliability Issues Steering Committee ("RISC") and Reliability and Security Technical Committee ("RSTC").
- Provide a forum for NPCC to participate, solicit and provide Regional comments to the Periodic Review Process for standards.
- Identify prospective reliability issues associated with new or revised NERC Reliability Standards and their potential impact on the NPCC Region, (e.g., Regional differences).
- Propose solutions to standards development issues, emerging reliability risks and guide the development of the NERC Reliability Standards through comments and coordination of NPCC participation on the SAR, Periodic Review and Reliability Standard Drafting Teams (SDT).
- Engage participants across the NPCC membership during the standard commenting process to achieve broad Regional consensus.
- Follow up on proposed and adopted changes to the NERC SPM and RoP as they apply to Reliability Standards and provide NPCC members with information to achieve a common understanding of the processes.

- Coordinate the activities of NPCC members on SDTs and encourage NPCC representation on all SDTs.
- Coordinate with the NPCC CC on input to CMEP Implementation Guidance documents in accordance with the CC process for submitting implementation guidance to NERC.
- Participate in the NERC Standards Efficiency Review and coordinate Regional participation in related efforts.
- Conduct DER and VER forums to promote best practices and information sharing as NPCC experiences increased penetration of DER and VER.
- Conduct outreach with State and Provincial Governmental authorities to provide an industry point of contact for regulatory mandates.
- Promote the targeted reliability activities in the NPCC Strategic Plan and the ERO Long term strategy focus areas.

D. FERC Activities Affecting Standards

The RSC will review and discuss FERC Orders and NOPR relating to ERO and Regional Reliability Standards.

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

E. Non-Jurisdictional

The RSC will conduct activities as necessary to promote reliable integration of new resources including but not limited to DER and VER. The focus of the RSC activities is to inform stakeholders of new technologies, planning techniques, operational impact, and opportunities to leverage the characteristics of new technologies to provide and enhance essential reliability services. Provide support for Regional de-carbonization goals by monitoring NPCC Criteria and Directory development and revision for reliability, security, and resilience issues as well as impediments to meeting decarbonization goals. Additionally, the RSC will develop, and revise guidance documents and procedures related to these new technologies.

NPCC Board of Directors Meeting
XX_XX, 2024
Draft for Approval, Agenda Item XX

Northeast Power Coordinating Council, Inc.
Regional Standards Committee
Work Plan for Calendar Years 2024-2025

The following Regional Standards Committee ("RSC") Work Plan activities for the calendar years of 2024-2025 will be consistent with the NPCC 2024 and 2025 Business Plans and Budgets, 2024-2027 Working Draft Strategic Plan, and continues to support the Distributed and Variable Energy Resource Forums along with other reliability activities related to de-carbonization goals in the Region. The Work Plan supports the 2024 ERO Enterprise Work Plan Priorities and the ERO Reliability Standards Development activities including ongoing standards periodic reviews, standards development, standards efficiency reviews, and standards grading.

NPCC Reliability Standards Committee Program Responsibilities (related to Standards)

The RSC's work will be informed by the Strategic Reliability Focus Areas defined in the 2024-2027 Working Draft NPCC Strategic Plan. Those focus areas are: 1) Enhancing System Resilience and Assuring Energy Sufficiency 2) Reliably Integrating the Resources brought forward by Societal Decarbonization 3) Addressing Cyber and Physical Threats.

1. Monitor NERC's Reliability Issues Steering Committee ("RISC") risk profiles and other reliability related issues and priorities. Review the 2023 ERO Reliability Risk Priorities Report for NERC and NPCC Standards and Criteria development, or for the development of guidelines or other reliability solutions. Coordinate NPCC's input into those decisions.
2. Coordinate and provide input to the development and prioritization of ERO reliability standards within the NERC Reliability Standards Development Plan through active Regional participation with the Periodic Review Standing Review Team or successor group or related activity.
3. Provide ongoing input to the NERC Standards Periodic Review Template used to determine the effectiveness of standards.
4. Continue to coordinate Regional input for cost effectiveness activities conducted during NERC's Standards Development program.
5. Oversee, and participate in the Regional Standards Development Process and base any development, revision, or retirement of NPCC Regional Reliability Standards on the continued reliability related needs of the Region or continent-wide ERO standards and initiate any future revision(s) which may be necessary.
6. Coordinate any NPCC Regional Standards development activity with NERC Standards development activity to avoid duplication and ensure resources are available for efficient and effective standards development and implementation.
7. Engage in the NERC Compliance Guidance Policy process. Support the inputs through the NPCC Compliance Committee ("CC") by providing technical and policy related opinions as necessary.
8. Coordinate NPCC participation in reviews and revisions of NERC Standards when addressing reliability directives from FERC and any Provincial Governmental Authority directives.
9. Participate in any NERC Task Forces, Working Groups, and Subcommittees which may drive NERC and NPCC standards development activities.
10. Conduct thorough reviews of all NERC Standards being developed or revised and coordinate timely consensus-based comments within the NPCC Region based on reliability needs, results-based requirements, and Periodic Reviews activities by leveraging the expertise of the NPCC RSC and Task Forces.
11. Develop and submit Standard Authorization Requests ("SARs") for revisions when necessary to improve Standards and address reliability related issues for approved or draft Standards.
12. Develop, as needed, any Interconnection Wide Regional variances for NERC Reliability Standards and NPCC Regional Standards in accordance with the NPCC Regional Standard Process Manual.

13. Summarize project development revisions and background for RSC members and NERC Registered Ballot Pool entities within NPCC for all NERC Standards under development.
14.
15. Provide guidance to NPCC Regional Standard Drafting Teams in critical areas of results-based Standards, Violation Severity Levels (VSL), and Violation Risk Factor (VRF) development as well as ensuring quality.
16. Respond to FERC and Provincial filings and interrogatories on issues related to Regional and NERC Standards as requested. Coordinate formal NPCC input to NERC filings and petitions.
17. Serve as a liaison for the Northeast Region to the NERC RISC for all new and emerging reliability risks related to the development or revision of standards.
18. Coordinate input for the Northeast Region to the NERC Reliability and Security Technical Committee ("RSTC") as necessary.
19. Participate in or observe the proceedings of various NERC groups to contribute to the continued improvement of NERC Standards and processes. These groups include but are not limited to:
    a. NERC Standards Committee ("SC")
    b. NERC Standards Committee Process Subcommittee ("SCPS")
    c. NERC Project Management Oversight Subcommittee ("PMOS")
    d. NERC SAR and Standards Drafting Teams ("SDTs")
    e. NERC RISC
    f. NERC RSTC
20. Develop proposals for standards, variances, and standard clarifications utilizing Regional technical resources as assigned by the NPCC Reliability Coordinating Committee (RCC), or RSC.
21. Work with the NPCC CC and Staff to develop the necessary compliance elements of the Regional Standards, for example, VSLs.
22. Revise, as necessary, and implement the NPCC Cost Effective Analysis Procedure and apply it to Directories being revised or developed, as needed. Promote and participate in any NERC cost effectiveness analysis activities conducted during formal industry comment periods of the ERO draft continent-wide Standards.
23. Ensure that the appropriate NPCC Task Forces review NERC Standards-related issuances and provide input to support development of a NPCC consensus opinion based on cost effectiveness.
24. Solicit technically qualified candidates from NPCC stakeholder companies to participate on each of the NERC Standard Drafting Teams. Ensure sufficient regional representation exists on the drafting teams.
25. Promote among NPCC stakeholders, and State and Provincial regulators issues related to BES reliability and Standards development.
26. Participate in NPCC Compliance and Reliability Conferences.
27. Participate in the revision and redrafting of the NERC Rules of Procedure (RoP) and other documents related to standard development as the NERC documents come up for review and /or modification.
28. Coordinate implementation of the NERC Standards development processes and NPCC Regional Standard processes and recommend revisions as necessary.
29. Coordinate with the RCC, all activities related to input received from the "Distributed Energy Resources(DER)/Variable Energy Resource (VER) BES Impact Reporting Form."
30. Provide oversight, and further develop as may be necessary, the process, information, and promotion of the "DER/VER BES Impact Reporting Form."
31. Conduct DER/VER Forum Meetings as required.
32. Develop revisions to and maintain NPCC DER/VER Guidance document(s) and processes.
33. Coordinate and work with State and Provincial Governmental Authorities to address reliability and resilience related issues associated with DER/VER, and energy storage as decarbonization goals are pursued.

NPCC Regional Standards Committee Program Responsibilities (related to Criteria and Directories)

1. Coordinate NPCC Directory Development activities with the regulatory authorities in the U.S. and applicable Provincial Governmental Authorities.
2. Identify the need for new or modified NPCC Criteria and Directories, Guidelines and Procedures pursuant to Section 313 of the NERC ROP responsibilities.

3. Revise and maintain the NPCC Directory Development and Revision Manual & Process for the Review and Approval of Criteria, Guidelines, and Procedures as needed to identify incremental reliability benefit and cost effectiveness as directed by the NPCC Board of Directors (BOD) and Full Members.
4. Coordinate Criteria and Directories requirements with Regional and NERC Standards requirements to ensure no inconsistencies or duplication exists and identify potential areas for improvements.
5. Develop filings for the Directories for the New York State Public Service Commission to fulfill obligations for the "Carve-out" outlined in Order 672 for mandatory adherence to more stringent Regional criteria for New York State.
6. Develop filings of Directories as required with the Provincial Governmental Authorities as per the various Memorandums of Understanding.
7. Announce development activities pertaining to the NPCC Reliability Directories and NPCC guidance documents which will enable users, owners, and operators of the Bulk Power System in the Region to be aware of and apply the NPCC Regionally specific criteria.

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

RSC Meeting
December 7, 2023
Agenda Item #3.2

December 3, 2023

Members, Reliability Standards Committee

Subject: **NPCC 2023 Goal II-3 State and Provincial Regulator Outreach --- Quarterly Status Report**

Ladies and Gentlemen:

NPCC 2023 Corporate Goal II-3 calls for the completion of three (3) briefings with State and Provincial Regulators on NERC and NPCC reliability assessments to promote awareness of effective regional transmission planning in the face of the changing resource mix and also the completion of a fourth briefing to identify specific Northeast emerging reliability risks.

On March 31, 2023, NPCC conducted an outreach session with State and Provincial Regulators focused on regional cyber and physical challenges. During the session, a representative from the Electricity Information Sharing and Analysis Center (E-ISAC) provided insight on the E-ISAC's engagement with asset owners and the analysis of security threats and mitigation strategies. During the same session, a NPCC Staff member described partnerships with local and state law enforcement agencies and the current cyber and physical regional threats to the energy sector.

On May 19, 2023, an outreach briefing was conducted focused on NERC 's 2023 Summer Reliability Assessment (SRA) and NPCC's regional Reliability Assessment and Performance (RAPA) activities in support of the SRA. Additionally, on July 28th, 2023, another session highlighted the NERC 2023 State of Reliability Report (SOR), and also provided an overview of the NERC Level 3 Alert: Essential Actions Cold Weather Preparations for Extreme Weather Events.

NPCC has scheduled an additional outreach session on December 14, 2023, focused on NERC's 2023-2024 Winter Reliability Assessment (WRA) and a summary of the Winter Storm Elliot Report.

Gerry Dunbar
Director, Reliability Standards and Criteria

Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas - 4th Floor
New York, New York 10018
(917) 608-5325
GDunbar@NPCC.org

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CIP Definitions

Project 2016-02 Modifications to CIP Standards
Draft 5

The standard drafting team (SDT) is seeking comment on the following new or modified terms used in the proposed standards. The first column (*NERC Glossary Term*) provides the NERC Glossary term being modified or proposed as a new. The SDT is proposing acronyms to some currently approved and new glossary terms as shown in redline. The second column (*Currently Approved Definition*) provides the currently approved definition and the third column (*CIP SDT Proposed New or Revised)* reflects the proposed modifications to the current definitions in redline and also reflects newly proposed definitions in clean view.

Table 1: Modified or Newly Proposed Definitions

NERC Glossary Term	Currently Approved Definition	CIP SDT Proposed New or Revised REDLINE TO Currently Approved
BES Cyber Asset (BCA)	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.	A Cyber Asset or Virtual 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~~Reliable Operation of the Bulk Electric System~~.~~ (BES). Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.
BES Cyber System (BCS)	One or more BES Cyber Assets logically grouped	

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Update is Acronym only.	by a responsible entity to perform one or more reliability tasks for a functional entity.	
BES Cyber System Information (BCSI)	Information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems, such as, but not limited to, device names, individual IP addresses without context, ESP names, or policy statements. Examples of BES Cyber System Information may include, but are not limited to, security procedures or security information about BES Cyber Systems, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the BES Cyber System	Information about the BES Cyber System (BCS) that could be used to gain unauthorized access or pose a security threat to the ~~BES Cyber System~~BCS. BES Cyber System Information (BCSI) does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to ~~BES Cyber Systems~~BCS, such as, but not limited to, device names, individual IP addresses without context, ~~ESP~~Electronic Security Perimeter names, or policy statements. Examples of ~~BES Cyber System Information~~BCSI may include, but are not limited to, security procedures or security information about ~~BES~~BCS, Shared Cyber ~~Systems~~Infrastructure, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the ~~BES Cyber System~~BCS.
CIP Senior Manager	A single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the NERC	A single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the NERC

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	CIP Standards, CIP-002 through CIP-011.	~~CIP~~Critical Infrastructure Protection Cyber Security Standards~~, CIP-002 through CIP-011.~~.
Cyber Assets	Programmable electronic devices, including the hardware, software, and data in those devices.	Programmable electronic devices, excluding Shared Cyber Infrastructure, including the hardware, software, and data in those devices. Application containers are considered software of Virtual Cyber Assets (VCAs) or Cyber Assets. VCAs are not considered software or data of Cyber Assets.
Cyber Security Incident	A malicious act or suspicious event that: - For a high or medium impact BES Cyber System, compromises or attempts to compromise (1) an Electronic Security Perimeter, (2) a Physical Security Perimeter, or (3) an Electronic Access Control or Monitoring System; or - Disrupts or attempts to disrupt the operation of a BES Cyber System	A malicious act or suspicious event that: • ~~-~~For a high or medium impact BES Cyber System~~,~~ (BCS), compromises or attempts to compromise (1) an Electronic Security Perimeter, (2) a Physical Security Perimeter, ~~or~~ (3) an Electronic Access Control or Monitoring System; or (4) Shared Cyber Infrastructure; or • ~~-~~Disrupts or attempts to disrupt the operation of a ~~BES Cyber System~~BCS.
Cyber System ***New Definition***		One or more Cyber Assets, Virtual Cyber Assets, or Shared Cyber Infrastructure.
Electronic Access Control or Monitoring Systems (EACMS)	Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber	Cyber ~~Assets~~System(s) that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber

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	Systems. This includes Intermediate Systems.	Systems (BCS). ~~This includes Intermediate Systems.~~, including those not protected by an Electronic Security Perimeter used by the responsible entity to convert routable protocol communications to non-routable communications to a BCS.
Electronic Access Point (EAP)	A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.	~~A~~An electronic policy enforcement point or a Cyber Asset interface on an Electronic ~~Security Perimeter~~Access Control or Monitoring Systems that ~~allows~~controls routable communication ~~between~~to and from one or more BES Cyber Systems or their associated Protected Cyber Assets ~~outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.~~.
External Routable Connectivity (ERC)	The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection.	The ability to access a BES Cyber System ~~from a Cyber Asset that is outside of its associated~~through its Electronic Security Perimeter via a bi-directional routable protocol connection.
Electronic Security Perimeter (ESP)	The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.	The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol; or a logical boundary defined by one or more Electronic Access Points.
Interactive Remote Access (IRA)	User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within	User-initiated electronic access by a person ~~employing a remote access client or other remote access technology~~ using a bi-directional routable protocol ~~. Remote access originates from a Cyber Asset that is not an Intermediate~~ :

Table 1: Modified or Newly Proposed Definitions		
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	any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.	• To a Cyber System ~~and not located within any of the Responsible Entity's~~ protected by an Electronic Security Perimeter(s) ~~or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) (ESP);~~ • That is converted by the responsible entity to a non-routable protocol that allows access to a Cyber ~~Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants.~~ System; or • To a Management Interface. Interactive ~~r~~Remote ~~a~~Access does not include ~~system~~: • Communication that originates from a Cyber System protected by any of the Responsible Entity's ESPs; or System-to-system process communication~~s~~.
Intermediate System	A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.	~~A Cyber Asset~~One or ~~collection of Cyber Assets performing access control~~more Electronic Access Control or Monitoring Systems that are used to restrict Interactive Remote Access to only authorized users. ~~The Intermediate System must not be located inside the Electronic Security Perimeter.~~

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Management Interface *New Definition*		An administrative interface that: • Controls the processes of initializing, deploying, and configuring Shared Cyber Infrastructure; • Is an autonomous subsystem that provides access to the console independently of the host system's CPU, firmware, and operating system; or • Configures an Electronic Access Point.
Physical Access Control Systems (PACS)	Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers	Cyber ~~Assets~~Systems that control, alert, or log access to the Physical Security Perimeter(s) (PSP), exclusive of locally mounted hardware or devices at the ~~Physical Security Perimeter~~PSP such as motion sensors, electronic lock control mechanisms, and badge readers.
Physical Security Perimeter (PSP)	The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.	The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, Shared Cyber Infrastructure, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.
Protected Cyber Asset (PCA)	One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP.	One or more Cyber Assets ~~connected using a routable protocol within~~ or ~~on~~Virtual Cyber Assets that: • Are protected by an Electronic Security Perimeter ~~that is~~(ESP) but are not part of the highest impact BES Cyber System ~~within~~(BCS) protected by the same ~~Electronic Security Perimeter. The impact~~

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		~~rating~~ESP; or • Share CPU resources or memory resources with any part of ~~Protected Cyber Assets is equal to~~ the ~~highest rated BES~~BCS, excluding Virtual Cyber ~~System~~Assets that are being actively remediated in ~~the same ESP.~~an environment that isolates routable connectivity from BCS; Excluding Transient Cyber Assets.
Removable Media	Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a Protected Cyber Asset. Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.	Storage media that (i) are not Cyber Assets~~,~~ or Shared Cyber Infrastructure (SCI), (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, SCI, a network ~~within~~protected by an ~~ESP~~Electronic Security Perimeter, or a Protected Cyber Asset. ~~Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.~~
Reportable Cyber Security Incident	A Cyber Security Incident that compromised or disrupted: - A BES Cyber System that performs one or more reliability tasks of a functional entity; - An Electronic Security Perimeter of a high or medium impact BES Cyber System; or	A Cyber Security Incident that compromised or disrupted: • ~~–~~A BES Cyber System (BCS) that performs one or more reliability tasks of a functional entity; • ~~–~~An Electronic Security Perimeter of a high

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	- An Electronic Access Control or Monitoring System of a high or medium impact BES Cyber System	or medium impact ~~BES Cyber System; or~~BCS; • ~~-~~An Electronic Access Control or Monitoring Systems of a high or medium impact ~~BES~~BCS; or • Shared Cyber ~~System~~Infrastructure supporting a BCS.
Shared Cyber Infrastructure (SCI) ***New Definition***		One or more programmable electronic devices, including the software that shares the devices' resources, that: • Hosts one or more Virtual Cyber Assets (VCA) included in a BES Cyber Systems (BCS) or their associated Electronic Access Control or Monitoring Systems (EACMS) or Physical Access Control Systems (PACS); and hosts one or more VCAs that are not included in, or associated with, BCS of the same impact categorization; or • Provides storage resources required for system functionality of one or more Cyber Assets or VCAs included in a BCS or their associated EACMS or PACS; and also for one or more Cyber Assets or VCAs that are not included in, or associated with, BCS of the same impact categorization. SCI does not include the supported VCAs or Cyber Assets with which it shares its resources.
Transient Cyber Asset (TCA)	A Cyber Asset that is:	A Cyber Asset or Virtual Cyber Asset (VCA) that is:

Table 1: Modified or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised REDLINE TO Currently Approved**
	1. capable of transmitting or transferring executable code, 2. not included in a BES Cyber System, 3. not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and 4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a: • BES Cyber Asset, • network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or • PCA associated with high or medium impact BES Cyber Systems. Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.	1. ~~c~~Capable of transmitting or transferring executable code, 2. ~~n~~Not included in a BES Cyber System (BCS), 3. ~~n~~Not a Protected Cyber Asset (PCA) associated with high or medium impact ~~BES Cyber Systems~~BCS, and 4. ~~directly c~~Connected for 30 consecutive calendar days or less: • On a network protected by an Electronic Security Perimeter (ESP) containing high or medium impact BCS, or • Directly (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) ~~for 30 consecutive calendar days or less to a:~~to a: ~~•~~ BES Cyber Asset, ▪ ~~network within an Electronic Security Perimeter (ESP) containing high~~ or ~~medium impact BES Cyber Systems, or~~ ▪ Shared Cyber Infrastructure, or ▪ PCA associated with high or medium impact ~~BES Cyber Systems~~BCS.

Table 1: Modified or Newly Proposed Definitions		
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		~~Examples of~~ Virtual machines hosted on a physical Transient Cyber Asset~~s~~ (TCA) are treated as software on that physical TCA. Examples of TCAs include, but are not limited to, Cyber Assets or VCAs used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
Virtual Cyber Asset (VCA) ***New Definition***		A logical instance of an operating system or firmware, currently executing on a virtual machine hosted on a BES Cyber Asset; Electronic Access Control or Monitoring System; Physical Access Control System; Protected Cyber Asset; or Shared Cyber Infrastructure (SCI). Virtual Cyber Assets (VCAs) do not include: • Logical instances that are being actively remediated in an environment that isolates routable connectivity from BES Cyber Systems; • Dormant file-based images that contain operating systems or firmware; and • SCI or Cyber Assets that host VCAs. Application containers are considered software of VCAs or Cyber Assets.

Standard Development Timeline

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

Description of Current Draft

45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting (SAR submitted by NERC RS)	June 14, 2017
Standards Committee approved Standard Authorization Request (SAR) for posting (SAR submitted by NWPP FRSG)	October 18, 2017
SAR posted for comment (SAR submitted by NERC RS)	June 16, 2017 – July 18, 2017
SAR posted for comment (SAR submitted by NWPP FRSG)	November 2, 2017 – December 1, 2017
Reliability Standard BAL-003-2	November 5, 2019

Anticipated Actions	Date
45-day formal comment period with ballot	July 25, 2022
45-day formal comment period with additional ballot	~~TBD~~April 18, 2023
10-day final ballot	TBD
Board adoption	TBD

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

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

Term(s):

The BAL-003-3 Standard Drafting Team (SDT) proposes that the currently-approved Texas RE Regional definition of **Governor** to be made part of the NERC Glossary of Terms generally.

Governor – The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.

The BAL-003-3 Standard Drafting Team (SDT) proposes that the currently-approved Texas RE Regional definition of **Primary Frequency Response** to be made part of the NERC Glossary of Terms generally:

Primary Frequency Response – The immediate proportional increase or decrease in real power output provided by generating units/generating facilities in response to system Frequency Deviations. This response is in the direction that stabilizes frequency.

These terms are also used in other standards, as indicated below. The BAL-003-3 SDT is obligated to review other standards in which these terms are used to determine if reliability gaps or redundancies are created by the proposed revision to the defined terms. The BAL-003-3 SDT has determined that the proposed definitions do not change the reliability intent of other requirements or definitions. The following is the standard using the terms Governor and Primary Frequency Response:

BAL-001-TRE – Primary Frequency Response in the ERCOT Region: The BAL-003 SDT determined that the proposed definition revision will not create any redundancies or gaps in reliability.

A. Introduction

1. **Title: Frequency Response and Frequency Bias Setting**

2. **Number: BAL-003-23**

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing AuthorityResponsible Entity

   4.1.1.1. Balancing Authority

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

   4.1.1.2. Frequency Response Sharing Group

   4.1.2 Generator Operator

5. **Effective Date:** See Implementation Plan for BAL-003-32.

B. Requirements and Measures

R1. Each Responsible Entity shall achieve an annual Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annualFrequency Response Compliance Measure (FRCM) (as calculated and reported in accordance with Attachment A) that is greater than or equal to one its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each Responsible Entity FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group Responsible Entity shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRCM (in accordance with the methods and data specified by the ERO in Attachment A) with data from FRS Form 1 reported to the ERO as specified in

~~Attachment A)~~ that is greater than or equal to one ~~or more negative than its FRO~~ to demonstrate compliance with Requirement R1.

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

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

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

3.1 Less than zero at all times, and

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

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

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

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

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

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

R5. Each Generator Operator shall operate each generating unit/generating facility ~~that is~~ connected to ~~the~~an ~~interconnected~~Interconnection ~~transmission system~~ with its Governor in speed or frequency ~~responsive~~ controls mode unless: *[Violation Risk Factor = Medium] [Time Horizon = Real-time Operations]*

- The generating unit/generating facility is not equipped with a Governor;
- System operating conditions are incompatible with the generating unit/generating facility operating the Governor in speed or frequency control mode as determined by the Balancing Authority; or
- The generating unit/generating facility is being operated in start-up, shut-down, experiences a component failure, or other temporary mode that requires the Governor speed or frequency control mode to be temporarily disabled.

5.1 Other control modes, such as outer loop control, shall not override the Primary Frequency Response of the Governor.

M5. The Generator Operator shall have evidence to show that it operated each generating unit/generating facility connected to an Interconnection with its Governor in speed or frequency control mode as specified in Requirement R5, Part R5.1, unless it meets one of the bulleted exceptions. Examples of suitable evidence may include, but is not limited to, performance testing, records showing Primary Frequency Response of a unit to frequency disturbances, appropriate documentation and/or control system settings that show the Governor is enabled (droop, deadband, control mode enable/disable, etc., as applicable). Requirement R5 does not require a Generator to operate with headroom, as stated in FERC Order No. 842, P109.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Generator Operator shall retain evidence of notifications made to the Balancing Authority for the current year and the previous five (5) calendar years for Requirement R5 and Measure M5.
- If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The ~~Balancing Authority's, or Frequency Response Sharing Group's,~~Responsible Entity's FRCM was less ~~negative~~ than ~~its FRO by at most~~ 100% by at most 15%~~ or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO~~.	The ~~Balancing Authority's, or Frequency Response Sharing Group's~~Responsible Entity's, FRCM was less ~~negative~~ than 100 % ~~its FRO~~ by more than 15% but by at most 30%~~ or 30 MW/0.1 Hz, whichever is the greater deviation from its FRO~~.	The ~~Balancing Authority's, or Frequency Response Sharing Group's~~Responsible Entity's, FRCM was less ~~negative~~ than 100% ~~its FRO~~ by more than 30% but by at most 45%~~ or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO~~.	The ~~Balancing Authority's, or Frequency Response Sharing Group's~~Responsible Entity's, FRCM was less ~~negative~~ than 100% ~~its FRO~~ by more than 45%~~ or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO~~.
R2.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its Reporting ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its Reporting ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its Reporting ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its Reporting ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.

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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	validated or calculated value.	of the validated or calculated value.	of the validated or calculated value.	The Balancing Authority failed to change the Frequency Bias Setting value used in its Reporting ACE calculation when providing Overlap Regulation Services.
R5.	N/A	N/A	N/A	The Generator Operator did not operate with the Governor in service and did not meet any of the exemption criteria. OR Generator is operating in a control mode that overrides the Governor response.

D. Regional Variances

None.

E. Associated Documents

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

~~FRS Form 1~~

~~FRS Form 2~~

Link to the Implementation Plan

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial; updated version number to "0.1b"	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	

Version	Date	Action	Change Tracking
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata
2	November 5, 2019	NERC Board of Trustees adopted BAL-003-2	New
2	July 15, 2020	FERC Letter Order approved errata to BAL-003-2. Docket RD20-9-000	
3	November 5, 2019	NERC Board of Trustees adopted BAL-003-3.	Complete Revision under Project 2017-01 Phase II
3	July 15, 2020	FERC Order issued approving BAL-003-3.	

Standard Attachments

Attachment A

BAL-003-~~2~~3 Frequency Response and Frequency Bias Setting Standard

Supporting Document

Overview of IFRO, FRO, SEFRD, FRM, FRCM, and FBS Calculations

There are several calculations needed to implement the Frequency Response and Frequency Bias Setting Standard. The Interconnection Frequency Response Obligation (IFRO) and Frequency Response Obligation (FRO) calculations are performed by the ERO annually. The Single Event Frequency Response Data (SEFRD), Frequency Response Measure (FRM), Frequency Response Compliance Measure (FRCM), and Frequency Bias Setting (FBS) calculations are performed by the individual BAs and/or FRSGs. The FBS, Most Severe Single Contingencies (MSSCs), and annual load and resource data are submitted by the BAs and evaluated by the ERO. These values are determinants in ERO calculations of IFRO for each interconnection and determination of FRO and minimum FBS for each Balancing Authority.

These calculations are performed at differing points in the annual Operating Year (OY) cycle. The chronology of the determination and use of these calculations is as follows: determination of the IFRO, determination of the individual Balancing Authority FROs and minimum FBSs, publication of frequency events through the OY, determination of SEFRDs, determination of FRM and FRCM, and determination of FBS.

Interconnection Frequency Response Obligation

The ERO, in consultation with regional representatives, has established a target reliability criterion for each Interconnection called the ~~Interconnection Frequency Response Obligation (~~IFRO~~)~~. ~~Preliminary~~ Illustrative values for OY 2023 are provided below. Certain values are assessed annually according to the methodology which is detailed in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

Interconnection	**Eastern**	**Western**	**~~ERCOT~~Texas**	**~~HQ~~Quebec**	Units
Max. Delta Frequency (MDF)	**0.420**	**0.280**	**0.405**	**0.947**	
Resource Loss Protection Criteria (RLPC)[1]	**~~3,209~~3,740**	**~~2,850~~3,069**	**~~2,750~~2,805**	**2,000**	MW
Credit for Load Resources (CLR)[1]			**~~1,209~~931**		MW
Current IFRO (OY ~~2018~~2023)	**-~~1,09~~15**	**-~~858~~1096**	**-~~381~~412**	**-~~179~~211**	MW/0.1 Hz
~~First Step target IFRO[1]Estimated Final target IFRO~~	**~~-915~~890**	**~~-10181~~1096**	**~~-380~~**	**~~-211~~**	~~MW/0.1 Hz~~

~~Second Step target IFRO[1, 2]~~	~~-815~~
~~Final target IFRO[1, 2]~~	~~-787~~

Table 1: Interconnection Frequency Response Obligations (base year ~~2017~~2023)

IFRO = -(RLPC – CLR)/~~Max Delta Freq~~MDF/10

1. *These values are evaluated annually for changes in each Interconnection.*

CLR: A load reduction program that meets all of the following requirements shall be utilized by an Interconnection to reduce the IFRO:

- ***1.1.*** *Is requisite to prevent activation of first stage of an Interconnection's under-frequency load shedding program (UFLS) for any resource loss less than or equal to the Interconnection's Resource Loss Protection Criteria (RLPC);*
- ***1.2.*** *Is non-proportional and automatically activated;*
- ***1.3.*** *Activates within 1 (one) second of the trigger frequency being reached;*
- ***1.4.*** *Exclusively reserved for Frequency Response during normal operations and does not participate in UFLS, Undervoltage Load Shedding Program (UVLS Program), or any other Ancillary Service, such as Contingency Reserve, and is not used for any other operator-initiated normal operations; and*
- ***1.5.*** *Available at least 95% of the time and is reviewed as part of the ERO analysis that determines the IFRO.*

Annual reductions

An annual reduction in absolute value ~~To reduce risk, the Eastern~~of an Interconnection's IFRO due to change to the RLPC, CLR, and/or the MDF will be limited to no greater ~~stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step-down process, Interconnection Frequency Response Measure (FRM) declines by more~~ than 10 percent~~, the ERO will halt the reduction in IFRO until such time that a determination can be made as to the cause of the degradation~~ of the existing Interconnection's IFRO or -100MW/.10 Hz, whichever is less negative. Multiple year reductions may be necessary to meet the final target IFRO. If during the step-down process the Interconnection's FRM as calculated by the ERO declines by more than 10 percent, the ERO will delay subsequent reduction in IFRO until such time that a determination can be made as to the cause of the disproportionate performance.

Balancing Authority Frequency Response Obligation ~~and Frequency Bias Setting~~

For a multiple Balancing Authority interconnection, the I~~nterconnection~~ FRO shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation as measured in MWh. The ~~FRO~~ allocation of IFRO to determine the FRO for each BA is calculated using the ~~will be based on the~~ following ~~method~~formula:

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

Where:

- Annual Gen_{BA} is the total annual output of generating plants within the Balancing Authority Area (BAA).
- Annual Load_{BA} is total annual Load within the BAA.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that I~~i~~nterconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that I~~i~~nterconnection.

Balancing Authorities that form, merge or transfer load or resource must notify the ERO of the change in footprint and corresponding changes in allocation prior to the change such that the net obligation to the Interconnection remains the same and so that FBS and FRO can be adjusted.

Annually, the ERO reviews the load and resource data submitted for all Balancing Authorities for each Interconnection in the format requested by the ERO. After such annual review, the ERO will post the following information for each Balancing Authority for the upcoming year:

- Minimum FBS
- FRO

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

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

Frequency Event Selections and Postings

The OY annual list of events for each interconnection are selected by the ERO using the Procedure for ERO Support of Frequency Response and FBS Standard. Events that trigger UFLS will not be selected as BAL-003 events. The ERO will publish the annual list for each interconnection in accordance with the timeline below. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities and FRSG(s) will be given 30 days from the date the ERO posts the official list of events to submit the required data.

ERO Posting and Data Submittal Form

The ERO shall alert responsible entities each year of the appropriate method for data submittal.

The ERO publication of the official list of events is included in the form to be used for annual data submittal. The submittal includes data needed for the determination of Interconnection RLPCs and IFROs, as well as calendar year Balancing Authority specific data needed for determination of the respective Balancing Authorities' FROs and minimum bias settings.

Interconnection RLPC and Minimum Bias Data Submittal Data Items:

- Largest potential resource loss within the Balancing Authority Area for the next ~~o~~Operating ~~y~~Year as detailed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard"
- Second largest potential resource loss within the Balancing Authority Area for the next ~~o~~Operating ~~y~~Year as detailed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard"
- The largest resource loss within the Balancing Authority Area that results from a RAS action initiated by a multiple contingency (N-2) event as detailed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard"
- CLR – this value will be used to adjust the Interconnection IFRO
- Balancing Authority Area resource (MWh) for the previous calendar year – this value will be used in the formula described above to determine the BA FRO
- Balancing Authority Area Net Energy for load (MWh) for the previous calendar year – this value will be used in the formula described above to determine the BA FRO
- Balancing Authority Area Integrated Hourly Peak load (MW) for the previous calendar year – this value will be used to determine the minimum (in absolute value) bias setting. The (absolute value) minimum is 0.9% of the annual BA peak load.

Desired FBS - may be set to a value between 100% to 125% of the Balancing Authority FRM if this value is more negative than the minimum Frequency Bias based on Peak Demand. If not more negative, then the Frequency Bias must be the minimum Bias based on Peak Demand.

For Balancing Authorities which supply or receive Overlap Regulation Service, the partnered Balancing Authority and the amount of overlap are to be provided.

The ERO submittal form also is used to collect data for each event as described in the following sections.

Single Event Frequency Response Data

The Balancing Authority will calculate its FRM and FRCM values from SEFRD, defined as: "the data from an individual event in a Balancing Authority area that is used to calculate its Frequency Response, expressed in MW/0.1Hz."

The SEFRD needed for evaluation is, at a minimum, the following Balancing Authority's Energy Management System (EMS) scan rate data items for the period 1 minute prior

through 5 minutes after the ERO-supplied event time (t0):

- Actual frequency (F_A)
- Actual Net Interchange (NA_I) – for single BA interconnections, this value may be zero (0)
- Net resource or load loss – for single Balancing Authority interconnections, this value is needed for each event; for multiple Balancing Authority interconnections, this value is only to be reported by the Balancing Authority (or pro rata by multiple Balancing Authorities if a jointly owned unit) which sustained the resource loss. Lost load values are to be specified as a negative amount; lost resource values are to be specified as a positive amount.

Balancing Authorities may choose to apply certain adjustments to their calculations to account for factors such as nonconforming loads. For any such adjustments used, the SEFRD shall include the EMS scan rate data for the period 1 minute prior to through 5 minutes after the ERO-supplied event time (t0). The types of adjustments that are allowed are:

- non-conforming loads (load values specified as a negative amount),
- pumped hydro operation (load values specified as a negative amount, resource values specified as a positive amount),
- jointly owned unit dynamic schedules (import values specified as a negative amount, export values specified as a positive amount), and
- transferred frequency response (receipt values specified as a negative amount, delivered values specified as a positive amount).

For each of these adjustments, a given adjustment must be made for either all events or none of the events in an evaluation year.

All events provided by the ERO need to be included in the annual evaluation to determine the annual FRCM. A Balancing Authority may exclude an event only if, during any part of the event evaluation period:

- its tie-line data or its Frequency data was corrupt,
- its EMS was unavailable, or
- its Balancing Authority was completely islanded from the remainder of the Interconnection.

Determination of Balancing Authority Event Time (t_0) and Data Alignment

Because a particular BA's EMS scan can occur anywhere within a 2-- to -6- second window, the ERO specified event time (t_0) may not exactly align with a given BA's EMS scan. For each event, the Balancing Authority must review its frequency scan data and determine the last frequency scan prior to the frequency deviation (decline for a resource loss, spike for a load loss). The Balancing Authority should set the time of that scan as the Balancing Authority's event time (t_0) for that event. The time of the Balancing Authority's event time (t_0) should be within one scan of the frequency deviation.

In addition to the determination of the Balancing Authority's t_0, a review of the other

data items collected should be made to determine if a time shift is needed ~~of~~for any of these items relative to the times of the frequency scans. These shifts may be needed due to data transfer lags (e.g., dynamic signals transferred between Balancing Authorities via ICCP). If such a shift is needed, data item scans should be shifted to align to the times of the frequency scans.

Determination of the pre-event sample period (commonly known as the A space) and the post-event sample period (commonly known as the B space) shall be measured from the Balancing Authority determined event time (t_0).

Single Event Frequency Response Measure

Pre-event values (A value scans) for each data item used (actual frequency, net actual interchange, contingency loss, non-conforming loads, pumped hydro operation, jointly owned unit dynamic schedules, and/or transferred frequency response) will be the EMS data scans over the 16-second period before the Balancing Authority's event time (t_0) up to but excluding the Balancing Authority's event time (t_0).

The A value will be the average of the selected scans for that item. For low frequency events, the pre-event frequency value (frequency A value) will be calculated as the minimum of 60.000 Hz or average actual starting frequency. For high frequency events, the pre-event frequency value (frequency A value) will be calculated as the maximum of 60.000 Hz or average actual frequency.

Post-event (B value scans) for each data item used will be the EMS data scans over 20 to 52 seconds after the Balancing Authority's event time (t0). For each item used, the B value for that item will be the average of the selected scans for that item.

The number of scans for each average value in the computation of A and B values will be dependent on the data scan rate of the Balancing Authority's EMS. Calculation of the A value should contain data from at least three distinct time points and the calculation of the B value should contain data from at least five distinct time points.

The pre-event MW value is the average of the A values (scan values) of all of the data items (except frequency) used. Each of the data items must use the sign convention as noted in the listings above. Similarly, the post-event MW value is the average of the B values (scan values) of all of the data items (except frequency) used, again using the appropriate sign convention for each item.

The total MW change is determined by subtracting the average post-event MW value from the average pre-event MW value. Similarly, the frequency change is determined by subtracting the average post-event frequency value (frequency B value) from the average pre-event frequency value (frequency A value).

The Single Event Frequency Response Measure (event FRM) is determined by dividing the total MW change by the total frequency change.

If a Balancing Authority uses the transferred frequency response adjustment, an additional calculation will be needed. BAs will need to calculate the event FRMs

without incorporating transferred frequency response adjustments. This "FRM w/o Trfr" value is needed to calculate the Balancing Authority's Bias Setting, but it is not used to calculate the Balancing Authority's event FRCMs. The event FRMs including transferred frequency response are the values used to calculate event FRCMs.

Single Event Frequency Response Compliance Measure

The FRCM for each event is the ratio of FRM to FRO (FRM divided by FRO).

For FRSGs, the FRSG FRM for each event is calculated by dividing the sum the active Balancing Authorities' FRMs by the sum of the active Balancing Authorities' FROs. If a Balancing Authority is an FRSG participant and meets the requirements for excluding an event, e.g. loss of telemetry during event, the FRSG shall exclude the Balancing Authority's FRO and FRM from the FRSG's calculation of FRCM for the excluded event. For any event in which more than 50% of the Balancing Authority participants' data is excluded, the FRSG shall exclude that event for the FRSG.

Annual (OY) Frequency Response Measure and Frequency Response Compliance Measure

The Balancing Authority's FRM for the OY is determined by taking the median of the individual event FRM values.

The Balancing Authority's FRCM for the OY is determined by taking the median of the individual event FRCM values. An FRSG or a Balancing Authority providing Overlap Regulation Service will provide individual event FRCMs for the aggregate of its active participants.

Balancing Authority Fixed Frequency Bias Setting

A Balancing Authority in an Interconnection with multiple Balancing Authorities using a fixed FBS sets its FBS to the more negative value than:

- Any number the Balancing Authority chooses between 100 percent and 125 percent of its Frequency Response Measure
- Balancing Authority Minimum Frequency Bias Setting as determined by the ERO

Balancing Authority Variable Frequency Bias Setting

A Balancing Authority in an Interconnection with multiple Balancing Authorities using a ~~fixed~~variable FBS sets its FBS such that it is:

- Less than zero at all times, and
- Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz

Balancing Authority and Frequency Response Group Reporting

Each Balancing Authority reports its previous year's FRM (both with and without

transferred frequency response adjustment), FRCM Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised FBS. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the format specified by the ERO.

- Once the data listed above is fully posted, the ERO will announce the implementation period for changing the FBS.~~Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or~~
- ~~Submit a joint Form 1 with the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities.~~

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

~~Each Balancing Authority reports its previous year's FRM, Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.~~

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

- ~~Frequency Bias Setting~~
- ~~Frequency Response Obligation (FRO)~~

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

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

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

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

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

~~Frequency Response Measure~~

~~The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event in a Balancing Authority area that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.~~ ~~The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is the change in its Net Actual Interchange on its tie lines with adjacent Balancing Authorities divided by the change in Interconnection frequency. Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_t) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year.~~[1]

~~The ERO will use a standardized sampling interval of approximately 16 seconds before the event, up to the time of the event for the pre-event NA_t, and frequency (A values), and approximately 20 to 52 seconds after the event for the post-event NA_t (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).~~

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

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

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

[1] ~~As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.~~

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

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

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

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

- Facilitate the assignment of Balancing Authority FRO
- Calculate Balancing Authority FRCM
- Determine Balancing Authority F~~requency~~ B~~ias~~ S~~ettings~~

Target Business Date	Activity
March 1	**Events for evaluation of FRM~~S~~ and FRCM ~~Form 1 is~~are posted by the ERO* with all selected events for the operating year for BA usage.**
April 1	**BAs and FRSGs complete their frequency response calculations~~forms~~ for all four quarters, including the BAs' FBS calculations, returning the results to the ERO in a format specified by the ERO.**
May 1	**The ERO validates FBS values, computes the sum of all FBS values for each Interconnection and determines the implementation schedule for changes to BAs FBS.**
May 15	**~~The~~ BAs and FRSGs provide data needed by NERC to calculate the IFRO and the IFRO allocation to each BA in the format specified by the ~~not required to file FERC Form 714 receive a request to provide load and generation data as described in the *Procedure for*~~ ERO ~~*Support of Frequency Response and Frequency Bias Setting Standard*~~** ~~**to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.**~~
June 1	~~The~~ BA implements ~~any~~ changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If the 4th quarter posting of events for evaluation of FR~~S~~M and FRCM ~~Form 1s~~ is delayed, the ERO may adjust the other timelines in this table ~~by a similar amount~~.

** Data specification~~Procedure~~ will be maintained on the ~~for~~ ERO website; for example Procedure for ERO Support of Frequency Response and Frequency Bias ~~Setting~~ Standard or its successor.

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 26, 2019
SAR posted for comment	July 30, 2019-August 28, 2019

Anticipated Actions	Date
45-day formal comment period with ballot	May 25, 2023 – July 10, 2023
45-day formal comment period with additional ballot	TBD
10-day final ballot	TBD
Board adoption	TBD

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

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

Term(s):

The PRC-005-7 Standard Drafting Team (SDT) proposes to modify the NERC Glossary of Terms definition of **Protection System** ~~to be modified~~:

Protection System – One or more of the following components:

- Protective relays and components of control systems which respond to ~~secondary~~measured electrical quantities and provide protective functions;
- Communications systems necessary for correct operation of protective functions;
- Voltage and current sensing devices providing inputs necessary for the correct operation of protective functions;
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply); and/or
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

This term is also used in other standards, as indicated below. The PRC-005-7 SDT is obligated to review other standards in which this term is used to determine if reliability gaps or redundancies are created by the proposed revision to the defined term. The PRC-005-7 SDT has determined that the proposed modified definition does not change the reliability intent of other requirements or definitions.

The Protection System definition was changed to ensure uniformity among all reliability standards. Components of control systems which respond to measured electrical quantities and provide protective functions provide the same functionality, and thereby present the same risk, to the Bulk Electric System as protective relays. The risk of such components has already been realized and addressed in certain standards (PRC-019 and PRC-24, for instance), but it is crucial that these devices be uniformly accepted for their functionality and risk to the Bulk Electric System in terms of configuration, physical and cyber security, operation, and redundancy.

Additionally, it is important to maintain reliability standards that are technology neutral and centered around risk to the Bulk Electric System. The previous definition of Protection System provided requirements for a specific technology (protective relays) and left ambiguity regarding these other devices which perform the same function. Likewise, to only address synchronous

generator excitation systems is again focusing on a specific technology and not the risk to the Bulk Electric System. It is for these reasons that these devices should be treated as components of a Protection System among all reliability standards to ensure not only that they are maintained, but that they are designed, configured, protected, and studied in a manner consistent with protective relays which provide the same functionality.

The proposed revisions to **Protection System** are intended to provide clarity on the inclusion of Components of control systems which measure and utilize similar quantities as protective relays and perform similar functions as protective relays.

- CIP-002-5.1a – BES Cyber System Categorization
- CIP-003-8 – Cyber Security – Security Management Controls
- CIP-005-6 – Cyber Security – Electronic Security Perimeter(s)
- CIP-005-7 – Cyber Security – Electronic Security Perimeter(s)
- CIP-006-6 – Cyber Security – Physical Security of BES Cyber Systems
- CIP-007-6 – Cyber Security – Systems Security Management
- CIP-008-6 – Cyber Security – Incident Reporting and Response Planning
- CIP-009-6 – Cyber Security – Recovery Plans for BES Cyber Systems
- CIP-010-3 – Cyber Security – Configuration Change Management and Vulnerability Assessments
- CIP-010-4 – Cyber Security – Configuration Change Management and Vulnerability Assessments
- CIP-011-2 – Cyber Security – Information Protection
- CIP-013-2 – Cyber Security – Supply Chain Risk Management
- EOP-010-1 – Geomagnetic Disturbance Operations (in background section)
- IRO-010-2 – Reliability Coordinator Data Specification and Collection
- IRO-010-3 – Reliability Coordinator Data Specification and Collection
- PER-005-2 – Operations Personnel Training
- PER-006-1 – Specific Training for Personnel
- PRC-004-6 – Protection System Misoperation Identification and Correction
- PRC-012-2 – Remedial Action Schemes
- PRC-017-1 – Remedial Action Scheme Maintenance and Testing
- PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
- PRC-023-4 – Transmission Relay Loadability
- PRC-024-3 – Frequency and Voltage Protection Settings for Generating Resources
- PRC-025-2 – Generator Relay Loadability
- PRC-026-1 – Relay Performance During Stable Power Swings
- PRC-027-1 – Coordination of Protection Systems for Performance During Faults
- TOP-003-4 – Operational Reliability Data
- TPL-001-4 – Transmission System Planning Performance Requirements

- TPL-001-5.1 – Transmission System Planning Performance Requirements
- TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events

A. Introduction

1. **Title:** **Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**

2. **Number: PRC-005-~~6~~7**

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.1.4 UFLS-Only Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

   4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

   4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

   4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.

   4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, except for generators identified through Inclusion I4 of the BES definition, including:

   4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

   4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

   4.2.5.3 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator

bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 Protection Systems and Sudden Pressure Relaying for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:

4.2.6.1 Protection Systems and Sudden Pressure Relaying for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above.

4.2.7 Automatic Reclosing[1], including:

4.2.7.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group.[2]

4.2.7.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.7.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.7.3 Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.

5. **Effective Date:** See the Implementation Plan for ~~this standard~~ PRC-005-7.

6. **Definitions Used in this Standard:**

Automatic Reclosing – Includes the following Components:

- Reclosing relay

[1] Automatic Reclosing addressed in Section 4.2.7.1 and 4.2.7.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

[2] The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

- Supervisory relay(s) or function(s) – relay(s) or function(s) that perform voltage and/or sync check functions that enable or disable operation of the reclosing relay
- Voltage sensing devices associated with the supervisory relay(s) or function(s)
- Control circuitry associated with the reclosing relay or supervisory relay(s) or function(s)

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System
- Any one of the four specific elements of Automatic Reclosing
- Any one of the two specific elements of Sudden Pressure Relaying

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning*]

The PSMP shall:

1.1 Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries, non-battery based energy storage and alternative electro-chemical based energy storage associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2 Include the applicable monitored Component attributes applied to each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components.

M1. Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall have a documented PSMP in accordance with Requirement R1.

For each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries, non-battery based energy storage and alternative electro-chemical based energy storage, associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5. (Part 1.2)

R2. Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and

maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

R3. Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R4. Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the PSMP for the Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R5. Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

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.

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

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

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

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

- For Requirement R1, the Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall each keep its current dated PSMP, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

- For Requirement R2, Requirement R3, and Requirement R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

- For Requirement R5 the Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

1.3. Compliance Monitoring and Enforcement Program ~~Assessment Processes~~:

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

~~**1.3.**~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Investigations~~

~~Self-Reporting~~

~~Complaints~~

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

~~None~~

Table of Compliance Elements

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (Part 1.2).	The entity failed to establish a PSMP. OR The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1). OR The entity's PSMP failed to include applicable station batteries, non-battery based energy storage and alternative electro-chemical based energy storage, associated with the dc supply Component Types in a time-based program (Part 1.1).
R2	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The entity failed to undertake efforts to correct five (5) or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than five (5) but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

D. Regional Variances

None.

E. ~~Interpretations~~Associated Documents

~~None.~~The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005-7 Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (March 2023)
2. Technical Rationale for Modification of Protection System Definition (March 2023)
3. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)

~~Supplemental Reference Documents~~

~~The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.~~

1. ~~*Supplementary Reference and FAQ - PRC-005-6 Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (July 2015)~~
2. ~~*Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)~~
3. ~~*Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758,* NERC System Protection and Control Subcommittee (December 2013)~~
4. ~~*Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – Supplemental Information to Support Project 2007-17.3: Protection System Maintenance and Testing (October 31, 2014)~~

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	February 7, 2006	Adopted by NERC Board of Trustees	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. Changed "Timeframe" to "Time Frame" in item D, 1.2.
1	March 16, 2007	PRC-005-1 Approved by FERC. Docket No. RM06-16-000	
1a	February 17, 2011	Adopted by NERC Board of Trustees	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers developed in Project 2009-17
1a	September 26, 2011	Approved by FERC. Docket No. RD11-5-000	
1b	November 5, 2009	Adopted by NERC Board of Trustees	Interpretation of R1, R1.1, and R1.2 developed by Project 2009-10
1b	February 3, 2012	FERC Order approving revised definition of "Protection System"	Per footnote 8 of FERC's order, the definition of "Protection System" supersedes interpretation "b" of PRC-005-1b upon the effective date of the modified definition (i.e., April 1, 2013) *See N. Amer. Elec. Reliability Corp.*, 138 FERC ¶ 61,095 (February 3, 2012).
1b	February 3, 2012	PRC-005-1b Approved by FERC. Docket No. RM10-5-000	

Version	Date	Action	Change Tracking
1.1b	May 9, 2012	Adopted by NERC Board of Trustees	Errata change developed by Project 2010-07, clarified inclusion of generator interconnection Facility in Generator Owner's responsibility
1.1b	September 19, 2013	PRC-005-1.1b Approved by FERC. Docket No. RM12-16-000	
2	November 7, 2012	Adopted by NERC Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Approved by NERC Standards Committee	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase "or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;" to the second sentence under the "Retirement of Existing Standards" section. (no change to standard version number)
2	December 19, 2013	PRC-005-2 Approved by FERC. Docket No. RM13-7-000	
2	March 7, 2014	Adopted by NERC Board of Trustees	Modified R1 VSL in response to FERC directive (no change to standard version number)
2(i)	November 13, 2014	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
2(i)	May 29, 2015	PRC-005-2(i) Approved by FERC. Docket No. RD15-3-000	

Version	Date	Action	Change Tracking
2(ii)	November 13, 2014	Adopted by NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No. 758 to include Automatic Reclosing in maintenance programs

Version	Date	Action	Change Tracking
3	February 12, 2014	Approved by NERC Standards Committee	Errata Change: The Standards Committee approved errata changes to correct capitalization of certain defined terms within the definitions of “Unresolved Maintenance Issue” and “Protection System Maintenance Program”. The changes will be reflected in the definitions section of PRC-005-3 for “Unresolved Maintenance Issue” and in the NERC Glossary of Terms for “Protection System Maintenance Program". (no change to standard version number)
3	March 7, 2014	Adopted by NERC Board of Trustees	Modified R1 VSL in response to FERC directive (no change to standard version number)
3	January 22, 2015	PRC-005-3 Approved by FERC. Docket No. RM14-8-000	
3(i)	November 13, 2014	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
3(i)	May 29, 2015	PRC-005-3(i) Approved by FERC. Docket No. RD15-3-000	
3(ii)	November 13, 2014	Adopted by NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 13, 2014	Adopted by NERC Board of Trustees	Added Sudden Pressure Relaying in response to FERC Order No. 758
4	Sept 17, 2015	PRC-005-4 Approved by FERC. Docket No. RM15-9-000	

Version	Date	Action	Change Tracking
5	May 7, 2015	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources.
6	November 5, 2015	Adopted by NERC Board of Trustees	Revised to add supervisory relays, the voltage sensing devices, and the associated control circuitry to Automatic Reclosing in accordance with the directives in FERC Order 803.
6	December 18, 2015	FERC Letter Order approving PRC-005-6. Docket No. RD16-2-000.	
7	TBD	Adopted by NERC Board of Trustees	

Table 1-1 Component Type - Protective Relays and Components of control systems which respond to measured electrical quantities and provide protective functions Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[3]	**Maintenance Activities**
Any unmonitored protective relay/Components not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays/Components: • Verify that protective function settings are as specified. For non-microprocessor relays/Components: • Test and, if necessary calibrate. For microprocessor relays/Components: • Verify operation of the relay/Components inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values that are essential to proper functioning of the Protection System.

[3] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relays and Components of control systems which respond to measured electrical quantities and provide protective functions Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[3]	**Maintenance Activities**
Monitored microprocessor protective relay/Components with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Protective function ~~S~~settings are as specified. • Operation of the relay/Components inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values that are essential to proper functioning of the Protection System.
Monitored microprocessor protective relay/Components with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay~~/~~/Component inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.

Any communications system with all of the following: • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation)~~.~~ (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs necessary for the correct operation of~~s~~ Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays or Components of control system.
Voltage and Current Sensing devices connected to microprocessor relays/control system Components with ac measurements that are continuously verified by comparison of sensing input values~~, as measured by the microprocessor relay,~~ to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage. Inspect: • Electrolyte level. • For unintentional grounds.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	18 Calendar Months	Verify: • Float voltage of battery charger. • Battery continuity. • Battery terminal connection resistance. • Battery intercell or unit-to-unit connection resistance. Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible. • Physical condition of battery rack.
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage. Inspect: • For unintentional grounds.
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	18 Calendar Months	Verify: • Float voltage of battery charger. • Battery continuity. • Battery terminal connection resistance. • Battery intercell or unit-to-unit connection resistance. Inspect: • Physical condition of battery rack.
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage. Inspect: • Electrolyte level. • For unintentional grounds.
	18 Calendar Months	Verify: • Float voltage of battery charger. • Battery continuity. • Battery terminal connection resistance. • Battery intercell or unit-to-unit connection resistance. Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage. Inspect: • For unintentional grounds.
	18 Calendar Months	Inspect: Condition of non-battery based dc supply.
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage or output voltage monitoring of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any alternative electro-chemical based energy storage ~~battery based~~ station dc supply with monitoring and alarming of battery string(s) continuity ~~the intercell and/or terminal connection detail resistance of the entire battery~~ (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery ~~Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and~~		No periodic verification of the intercell and terminal connection resistance is required ~~evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured~~.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
~~evaluating present values relative to baseline internal ohmic values for every cell/unit~~ (See Table 2).		
Any alternative electro-chemical based energy storage ~~Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA)~~ station dc supply ~~battery~~ with monitoring and alarming of integrity of all battery electrical connections~~each cell/unit internal ohmic value~~ (See Table 2).		No periodic verification of the battery continuity ~~inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery~~ is required.

Table 1-4(g) Component Type – Protection System Station dc Supply Using Alternative Electro-chemical Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System station dc supply with alternative electro-chemical based energy storage not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage. Inspect: • For unintentional grounds.
	18 Calendar Months	Verify: • Output voltage of battery charger. • Battery continuity. • Integrity of all battery electrical connections. Inspect: • Condition of alternative electro-chemical based energy storage station dc supply. • Physical condition of battery rack/cabinet/enclosure.
	1/3 of estimated lifetime (maximum of 6 years)	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay or Component of control system to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with RAS. (See Table 4-2(b) for RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored protective relay/Component not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays/Components: • Test and, if necessary calibrate. For microprocessor relays/Components: • Verify operation of the ~~relay~~ inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values that are essential to proper functioning of the Protection System.
Monitored microprocessor protective relay/Component with the following: • Internal self-diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Protective function ~~S~~settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values that are essential to proper functioning of the Protection System.
Monitored microprocessor protective relay with preceding row attributes and the following:	12 Calendar Years	Verify only the unmonitored ~~relay~~ inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
• AC measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays/Components.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS ~~relays~~ device and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the ~~relay~~ device to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS ~~relays~~ devices (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing and Supervisory Relay Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay or supervisory relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor reclosing or supervisory relays: • Test and, if necessary calibrate For microprocessor reclosing or supervisory relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing. For microprocessor supervisory relays: • Verify acceptable measurement of power system input values.
• Monitored microprocessor reclosing relay or supervisory relay with the following: Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2). For supervisory relay: • Voltage waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing. For supervisory relays: • Verify acceptable measurement of power system input values.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing and Supervisory Relay **Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval.**		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Monitored microprocessor reclosing relay or supervisory relay with preceding row attributes and the following: • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2). For supervisory relay: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing and Supervisory Relays that are NOT an Integral Part of an RAS Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing and Supervisory Relays that ARE an Integral Part of an RAS Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 4-3 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Voltage Sensing Devices Associated with Supervisory Relays Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-3, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that voltage signal values are provided to the supervisory relays.
Voltage sensing devices that are connected to microprocessor supervisory relays with ac measurements that are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure. (See Table 2)	No periodic maintenance specified	None.

Table 5 Maintenance Activities and Intervals for Sudden Pressure Relaying Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

~~Standard Attachments~~
PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

~~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 revisions to Automatic Reclosing:~~

~~To address directives from FERC Order No. 803 addressing Automatic Reclosing, the definition for Automatic Reclosing was revised to add supervisory relays, the associated voltage sensing devices, and the associated control circuitry.~~

~~Rationale for revisions to Component Type:~~

~~With the revision of the definition of Automatic Reclosing, there are four specific elements of this definition, rather than two as stated in the prior version.~~

Description of Current Draft

This is the first draft of the proposed Glossary Terms posted for a formal comment period and initial ballot.

Completed Actions	Date
Standards Committee approved Standards Authorization Request (SAR)	September 24, 2020
SAR posted for comment	December 16, 2020 – January 14, 2021

Anticipated Actions	Date
45-day formal comment period with initial ballot	November 16, 2023 – January 4, 2024
10-day final ballot	January 2024
NERC Board adoption	February 2024

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

Background:

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. The terms proposed below are intended to be used in MOD-026-2 and other inverter-based resource related standards.

Term(s):

Inverter-Based Resource (IBR): A source (or sink in the case of a charging battery energy storage system (BESS)) of electric power that is connected to the electric power system (transmission, sub-transmission, or distribution system), and that consists of one or more IBR Unit(s) operated as a single resource at a common point of interconnection. IBRs include solar photovoltaic (PV), Type 3 and Type 4 wind, BESS, and fuel cell.

IBR Unit: An individual device, or a grouping of multiple devices, that uses a power electronic interface(s), such as an inverter or converter, capable of exporting Real Power from a primary energy source or energy storage system, and that connect together at a single point on the collector system.

Background

- The drafting team (DT) utilized the IEEE 2800-2022 definitions as an initial basis for the IBR terms for the NERC Glossary of Terms and adjusted, as necessary. The DT acknowledges the efforts of the P2800 Wind and Solar Plant Interconnection Performance Working Group and IEEE members in developing those definitions.
- The IBR and IBR Unit definitions are intended to describe the technology and which types of technologies are considered IBR. An IBR is not defined by where it is connected or the size of the IBR. Therefore, the definitions do not define the applicability for Reliability Standards, voltage connection level, or facility capability level (MW/MVA). The applicability of IBR will be defined in the Applicability section of the respective Reliability Standards. Additionally, this is the DT's reasoning to include the phrase "connected to the electric power system (transmission, sub-transmission, or distribution system)," while excluding specific voltage connection and MW values within the IBR definition.
- There is a need to distinguish between the individual "IBR unit or device" and the "IBR plant/facility" as a whole, so that standards or requirements can be written for each, as necessary. Hence, the two definitions for IBR Unit and IBR.
- The term IBR is synonymous with the term "IBR plant/facility." An IBR includes the IBR Units, and the equipment designed primarily for delivering the power to a common point of interconnection (e.g., step-up transformers, collector system(s), main power transformer(s), power plant controller(s), reactive resources within the IBR plant, and a voltage source converter high-voltage direct current (VSC HVDC) system with a dedicated connection to the IBR).
- An inverter is a power electronic device that inverts DC power to AC sinusoidal power. A rectifier is a power electronic device that rectifies AC sinusoidal power to DC power. A converter is a power electronic device that performs rectification and/or inversion.
- IBRs have traditionally been considered "generating resources." An IBR is not a HVDC system (except for a VSC HVDC with a dedicated connection to an IBR), flexible ac transmission systems (FACTS) (e.g., static synchronous compensators (STATCOM) and static VAR compensators (SVC)), or any resources that are not inverter-based, e.g., gas and steam power plants with synchronous generators. The DT's intent with the phrase "IBRs include" is to articulate a specific list of IBRs. Therefore, other technologies not listed would not be considered an IBR.
- A hybrid IBR (e.g., BESS and solar PV) or collocated portions of a facility that are IBR (e.g., a BESS at synchronous generation facility) are considered an IBR.
- IBRs are capable of exporting Real Power and may also be capable of providing Reactive Power.
- Battery energy storage systems (BESS) are considered an IBR unit or IBR independent of whether the device is operating in a charging, idle, or discharging mode.
- The Project 2020-06 DT intends to use the Glossary Terms of IBR Unit and IBR for MOD-026-2. Additional standards development projects and related standards that may use these defined terms include:
    - Project 2020-02 Generator Ride-through (new PRC-029, modified PRC-024)
    - Project 2021-01 Modifications to PRC-019 and MOD-025
    - Project 2021-04 Modifications to PRC-002 (new PRC-028)

  - Project 2022-04 EMT Modeling
  - Project 2023-01 EOP-004 IBR Event Reporting
  - Project 2023-02 Performance of IBRs (new PRC-030)
- Distributed Energy Resources (DER) related projects that may or may not need to use IBR/IBR Unit if they end up with their own definition)
  - Project 2022-02 Modifications to TPL-001 and MOD-032 (DER)
  - Project 2023-05 FAC-001/FAC-002 DER
  - Project 2023-08 MOD-031 Demand and Energy (DER)

Standard Development Timeline

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

Description of Current Draft

This is the ~~first~~**second** draft of the proposed standard **being posted** for a formal 45-day comment period **and additional ballot**.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	March 4 – April 2, 2021

~~Anticipated Actions~~	~~Date~~
45-day formal or informal comment period with ballot	September – November 2022

Anticipated Actions	Date
45-day formal or informal comment period with additional ballot	~~February –~~ April **– June** 2023
10-day final ballot	~~May~~**July** 2023
Board adoption	August 2023

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

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

Term(s):

None.

A. Introduction

1. **Title:** Verification of Real and Reactive Power Capability for BES Facilities

2. **Number:** MOD-025-3

3. **Purpose:** To ensure that accurate information on Bulk Electric System (BES) Facility Real and Reactive Power capability is available for planning models used to assess BES reliability.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner

   4.1.2 Transmission Owner

   4.1.3 Transmission Planner

   4.2. Facilities: For the purpose of this standard, the term~~,~~ "applicable Facility" or "Facility" shall mean any one of the following:

   4.2.1 Individual generating resource identified through Inclusion I2 of the BES definition.

   4.2.2 Generating plant/Facility identified through Inclusion I2 of the BES definition.

   4.2.3 Generating plant/Facility of dispersed power producing resources identified through Inclusion I4 of the BES definition.

   4.2.4 Dynamic reactive devices identified through Inclusion I5 of the BES definition with a gross (individual or aggregate) nameplate rating greater than 20 MVA including, but not limited to:

   4.2.4.1 Synchronous condenser; and

   4.2.4.2 Flexible alternating current transmission system (FACTS) devices.

   4.2.5 **High-voltage direct current (**HVDC**)** terminal equipment including:

   4.2.5.1 Voltage source converter (VSC).

   4.2.6 **Facilities meeting an exclusion of the BES definition are exempt as an applicable Facility.**

5. **Effective Date:** see ~~Project 2021-01 Modifications to MOD-025 and PRC-019~~ Implementation Plan.

B. Requirements and Measures

R1. Each Generator Owner shall verify the Real Power and Reactive Power capability of its applicable Facilities and inform its Transmission Planner as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Verify the Real Power capability, if applicable, of its applicable Facilities in accordance with Attachment 1.

1.2. Verify the Reactive Power capability of its applicable Facilities in accordance with Attachment 1.

1.3. Submit the following information, in accordance with Attachment 2, to the Transmission Planner within 30 calendar days after the verification date~~:~~**. The verification date, as specified in Attachment 2, should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity.**

1.3.1. ~~One-line~~**Simplified one-line** diagram representing the **applicable** Facility;

1.3.2. Composite capability curve and associated PQ data table; and

1.3.3. Documentation ~~showing the engineering basis,~~**of the underlying assumptions, design criteria, and methods for the chosen** verification methodology ~~and/or applicable data for the verification method~~**from Attachment 1**.

M1. Each Generator Owner shall have evidence that it verified Real Power and Reactive Power capability of each **applicable** Facility, such as completed attachments or summary report(s); and have evidence that it submitted the information within 30 calendar days after the verification date to its Transmission Planner in accordance with Requirement R1.

R2. Each Transmission Owner shall verify the Real Power and Reactive Power capability of its applicable Facilities and inform its Transmission Planner as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Verify the Real Power capability, if applicable, of its applicable Facilities in accordance with Attachment 1.

2.2. Verify the Reactive Power capability of its applicable Facilities, in accordance with Attachment 1.

2.3. Submit the following information ~~per~~**, in accordance with** Attachment 2**,** to the Transmission Planner within 30 calendar days after the verification date~~:~~**. The verification date, as specified in Attachment 2, should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity.**

2.3.1. ~~One-line~~**Simplified one-line** diagram representing the **applicable** Facility;

2.3.2. Composite capability curve and associated PQ data table; and

2.3.3. Documentation ~~showing the engineering basis,~~**of the underlying assumptions, design criteria, and methods for the chosen** verification methodology ~~and/or applicable data for the verification method~~**from Attachment 1**.

M2. Each Transmission Owner shall have evidence that it verified Real Power and Reactive Power capability of each **applicable** Facility, such as completed attachments or summary report(s); and have evidence that it submitted the information within 30 calendar days after the verification date to its Transmission Planner in accordance with Requirement R2.

R3. Each Transmission Planner shall review the information submitted by each Generator Owner or Transmission Owner in accordance with Requirement R1, R2, or R4 and provide a written response **to the submitter** within 90 calendar days ~~containing~~**from receiving each submission. The written response shall contain** one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Notification that the Transmission Planner has **reviewed the information and has** not identified any technical concerns with the Real and Reactive Power capability information submitted by the Generator Owner or Transmission Owner; or
- Notification that the Transmission Planner has **reviewed the information and has** identified a technical concern, including the basis for the technical concern.

M3. Each Transmission Planner shall have evidence, such as a summary of items reviewed and dated correspondence of the notification, that it reviewed the information submitted and provided notification to the Generator Owner or Transmission Owner within 90 calendar days in accordance with Requirement R3.

R4. Each Generator Owner or Transmission Owner receiving a notification of a technical concern under Requirement R3 shall provide a written response to its Transmission Planner within 90 calendar days ~~containing~~**from receiving a notification. The written response shall contain** one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Updated capability information in accordance with ~~Requirements~~**Requirement** R1 or R2;
- A ~~mutually agreed upon~~ plan ~~with its Transmission Planner~~ to update the capability information in accordance with ~~Requirements~~**Requirement** R1 or R2; or
- Technical justification and supporting evidence for maintaining the existing capability information in accordance with ~~Requirements~~**Requirement** R1 or R2.

M4. Each Generator Owner or Transmission Owner shall have evidence that it responded to the Transmission Planner within 90 calendar days in accordance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- Each Generator Owner shall keep data or evidence of Requirement R1 since the most current verification for each applicable BES Facility.
- Each Transmission Owner shall keep data or evidence of Requirement R2 since the most current verification for each applicable BES Facility.
- Each Transmission Planner shall keep data or evidence of Requirement R3 for a rolling 12 month period.
- Each Generator Owner and Transmission Owner shall keep data or evidence of Requirement R4 for a rolling 12 month period.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The applicable entity provided all items in Requirement R1 Part 1.3, but did so between 31 and 90 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power capability in Part 1.1 and 1.2, per Attachment 1 Section 1 Item 3, but did so between ~~10 years (~~120 calendar months~~)~~ and 126 calendar months. OR The applicable entity verified the Real and Reactive Power capability in Part 1.1 and 1.2, per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 181 and 270 calendar days.	The applicable entity provided all items in Requirement R1 Part 1.3, but did so between 91 and 180 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power capability in Part 1.1 and 1.2, but failed to include the information required in Requirement R1, Part 1.3.1. OR The applicable entity verified the Real and Reactive Power capability in Part 1.1 and 1.2, per Attachment 1 Section 1 Item 3, but did so between 127 and 132 calendar months. OR The applicable entity verified the Real and Reactive Power capability in Part 1.1 and 1.2, per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 271 and 360 calendar	The applicable entity provided all items in Requirement R1 Part 1.3, but did so between 181 and 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power capability in Part 1.1 and 1.2, but failed to include the information required in Requirement R1, Part 1.3.3. OR The applicable entity verified the Real and Reactive Power capability in Part 1.1 and 1.2, per Attachment 1 Section 1 Item 3, but did so between 133 and 138 calendar months. OR The applicable entity verified the Real and Reactive Power capability in Part 1.1 and 1.2, per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 361 and 450 calendar	The applicable entity provided all items in Requirement R1 Part 1.3, but did so greater than 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power capability in Part 1.1 and 1.2, but failed to include the information required in Requirement R1, Part 1.3.2. OR The applicable entity verified the Real and Reactive Power capability in Part 1.1 and 1.2, per Attachment 1 Section 1 Item 3, but did so in more than 138 calendar months. OR The applicable entity verified the Real and Reactive Power capability in Part 1.1 and 1.2, per Attachment 1 Section 1 Item 2, 4, or 5, but did so in more than 450 calendar days.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		days.	days.	OR The applicable entity failed to verify the Real and/or Reactive Power capability in Part 1.1 and 1.2.
R2.	The applicable entity provided all items in Requirement R2 Part 2.3, but did so between 31 and 90 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 3, but did between ~~10 years (~~120 ~~calendar months)~~ and 126 calendar months. OR The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 181 and 270 calendar days.	The applicable entity provided all items in Requirement R2 Part 2.3, but did so between 91 and 180 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, but failed to include the information required in Requirement R2, Part 2.3.1. OR The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 3, but did so between 127 and 132 calendar months. OR The applicable entity verified the Real and Reactive Power	The applicable entity provided all items in Requirement R2 Part 2.3, but did so between 181 and 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, but failed to include the information required in Requirement R2, Part 2.3.3. OR The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 3, but did so between 133 and 138 calendar months. OR The applicable entity verified the Real and Reactive Power	The applicable entity provided all items in Requirement R2 Part 2.3, but did so greater than 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, but failed to include the information required in Requirement R2, Part 2.3.2. OR The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 3, but did so in more than 138 calendar months. OR The applicable entity verified the Real and Reactive Power

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 271 and 360 calendar days.	capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 361 and 450 calendar days.	capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 2, 4, or 5, but did so in more than 450 calendar days. OR The applicable entity failed to verify the Real and/or Reactive Power capability in Part 2.1 and 2.2.
R3.	The Transmission Planner provided a written response to the submitter, but it was provided between 91 to 120 calendar days after receiving the verified model information.	The Transmission Planner provided a written response to the submitter, but it was provided between 121 to 150 calendar days after receiving the verified model information.	The Transmission Planner provided a written response to the submitter, but it was provided between 151 to 180 calendar days after receiving the verified model information.	The Transmission Planner failed to provide a written response to the submitter. OR The Transmission Planner provided a written response to the submitter but it was provided more than 180 calendar days after receiving the verified model information.
R4.	The applicable entity provided a written response to its Transmission Planner, but it was provided between 91 to 120 calendar days after receiving a notification of technical concern.	The applicable entity provided a written response to its Transmission Planner, but it was provided between 121 to 150 calendar days after receiving a notification of technical concern.	The applicable entity provided a written response to its Transmission Planner, but it was provided between 151 to 180 calendar days after receiving a notification of technical concern.	The applicable entity failed to provide a written response to its Transmission Planner. OR The applicable entity provided a written response to its Transmission Planner, but it was provided greater than 180 calendar days after receiving a

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				notification of technical concern.

D. Regional Variances

None.

E. Associated Documents

~~None.~~

Reliability Guideline Power Plant Model Verification and Testing for Synchronous Machines, July 2018.

NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference, September 2020.

Version History

Version	Date	Action	Change Tracking
1	12/1/2005	1. Changed tabs in footer. 2. Removed comma after 2004 in "Development Steps Completed," #1. 3. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 4. Added "periods" to items where appropriate. 5. Changed apostrophes to "smart" symbols. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all instances of "regional" in section D.3. 8. Removed the word "less" after 94% in section 3.4. Level 4.	01/20/06
2	February 7, 2013	Adopted by NERC Board of Trustees	Revised per SAR for Project 2007-09 and combined with MOD-024-1
2	March 20, 2014	FERC Order issued approving MOD-025-2. (Order becomes effective on 7/1/16.)	
3	TBD	Adopted by NERC Board of Trustees	Revised per SAR for Project 2021-01

MOD-025-3 Attachment 1

Section I. Periodicity of verification:

The periodicity to verify the Real and Reactive Power capability for each applicable BES Facility is as follows:

1. The applicable entity designates the verification date and notates the verification date in a summary report (refer to Attachment 2). The verification date should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity.
2. Verify each new applicable Facility within 180 calendar days of its commercial operation date.
3. Verify each existing applicable Facility at a periodicity not to exceed ~~ten years~~**120 calendar months** from the last verification date~~.~~**, unless it meets the following condition:**
    - **The Facility has been on a planned or unplanned outage of 180 days or greater, which overlaps its scheduled verification date. Verify the applicable Facility within 180 calendar days of its return to service date.**
4. Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating and is expected to last more than 180 calendar days.

~~5. Verify an existing applicable Facility within 180 calendar days of its return to service date, if the Facility has a planned or unplanned outage of 180 calendar days or more which overlaps its scheduled verification date and has not had its capability verified within the past ten years.~~

Section II. Verification specifications for applicable Facilities:

1. For individual devices or generators greater than 20 MVA (gross nameplate rating) perform verification on an individual basis.
2. For individual devices or generators 20 MVA (gross nameplate rating) or less that are part of an applicable Facility greater than 75 MVA (gross nameplate rating) in aggregate, perform verification on an individual unit basis or in the aggregate, considering applicable modeling expectations of the respective Transmission Planner.
3. Create a simplified ~~key~~ one-line diagram representing the Facility (refer to Attachment 2). ~~The~~**Identify on the** one-line diagram ~~shall designate~~ where the composite capability curve created in Section II, Items 6-8 is represented.
    3.1. The **simplified** one-line **diagram** representing the Facility shall ~~include~~**represent** all auxiliary equipment expected to be in-service for normal operation, including dynamic and static reactive devices and auxiliary load, the **generator**

step-up (GSU**)**, and/or system interconnection transformer(s), unit auxiliary transformer(s), and station services auxiliary transformer(s).

4. If an applicable Facility has no leading or lagging capability, then it should be reported with no leading or lagging capability.

5. The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility **Real and Reactive Power** capability for all equipment expected to be in-service for normal operation. The engineering ~~review~~**analysis** or engineering ~~analysis~~**review documentation** shall include **the** underlying assumptions, design criteria, and methods used to create the ~~Facility~~**Facility's composite** capability curve under Section II, Items 6-8.

   - ~~Perform an engineering review of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations;~~

   - Utilize staged testing data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the ~~generator~~**Facility** capability; or

   - Utilize operational data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the ~~generator~~**Facility** capability~~.~~**; or**

   - **Perform an engineering review of all Real and Reactive Power Facility capability information including, but not limited to, in-service equipment design limitations, excitation limiter settings, and operational limitations.**

6. For an applicable Facility as identified in Section 4.2.1, 4.2.2, or 4.2.4.1, when performing verification on an individual unit basis, create a graphical representation of the steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The steady-state CCC shall include at a minimum the following:

   6.1. The generator **nameplate** steady-state Real Power and Reactive Power capability curve, or the synchronous condenser **nameplate** steady-state Reactive Power capability curve, provided by the equipment manufacturer. **If the equipment manufacturer curve is not available, the curve shall be derived using the best available data.**

      6.1.1 The curve shall represent generator/synchronous condenser capability at a nominal voltage of 1.0 per unit at the generator/synchronous condenser terminal; and

      6.1.2 The curve shall notate the operating conditions that dictate the power capability, for example H2 pressure, ambient temperature, or other conditions.

   6.2. Excitation limiters, if more restrictive than the equipment ~~manufacturer's~~**nameplate** capability curve, at nominal voltage 1.0 per unit;

6.3. Identification of any Real Power or Reactive Power operational limitations,[1] ~~.~~ if applicable;

6.4. Identification of the steady-state minimum (P_{min}) and maximum (P_{max}) Real Power output at the generator terminal(s), based on the least restrictive seasonal or operating conditions; and

6.5. Identification of final PQ curve, which defines the normal operating region.

7. For an applicable Facility as identified in Section 4.2.2 or Section 4.2.3, when performing verification in aggregate, create a graphical representation of the steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The steady-state CCC shall include at a minimum the following:

7.1. The steady-state Real and Reactive Power capability curve represented as an aggregate.

7.1.1 The curve shall represent Facility capability at a steady-state nominal voltage of 1.0 per unit at the common point of connection; and

7.1.2 The curve shall notate the operating conditions that dictate the power capability, for example H2 pressure, ambient temperature, or other conditions.

7.2. Aggregate Facility capability includes all auxiliary equipment expected to be in-service for normal operation, including dynamic and static reactive resources and auxiliary loads;

7.3. Identification of any Real Power or Reactive Power operational limitations, if applicable;

7.4. For inverter based resources, a description of all power plant controller and inverter control functions during normal operating conditions that dictate the aggregate Facility capability;

7.5. Identification of the steady-state minimum (P_{min}) and maximum (P_{max}) Real Power output at the common point of connection, based on the least restrictive seasonal or operating conditions; and

7.6. Identification of final PQ curve, which defines the normal operating region.

8. For an applicable Facility as identified in Section 4.2.4.2 and Section 4.2.5.1, create a graphical representation of the steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The steady-state CCC shall include at a minimum the following:

[1] Such as generator cooling, vibration, de-rated rotor, de-rated GSU transformer, generator bus de-rating, software limitations, or distributed control system (DCS) setpoints (outer-loop control system paths). This excludes fuel availability, such as water levels for hydro, cloud cover for PV, wind speed, or river level for run of river.

8.1. The HVDC **nameplate** steady-state Real Power and Reactive Power capability curve, or the FACTS device steady-state Reactive Power capability, provided by the equipment manufacturer. **If the equipment manufacturer curve is not available, the curve shall be derived using the best available data.**

8.1.1 The curve shall represent Facility capability at a steady-state nominal voltage of 1.0 per unit at the common point of connection; and

8.1.2 The curve shall notate the operating conditions that dictate the power capability, for example ambient temperature or other conditions.

8.2. Any limiters, if more restrictive than the equipment ~~manufacturer's~~**nameplate** capability curve(s), at nominal voltage 1.0 per unit;

8.3. Identification of any Real Power or Reactive Power operational limitations, if applicable;

8.4. A description of all control functions during normal operating conditions and a description of any Facility overload capabilities that dictate the aggregate Facility capability;

8.5. Identification of the steady-state minimum (P_{min}) and maximum (P_{max}) Real Power output at the common point of connection, based on the least restrictive seasonal or operating conditions; and

8.6. Identification of final PQ curve, which defines the normal operating region.

Section III. Staged test and operational data specifications:

1. Section III applies when a staged test and/or operational data verification methodology is utilized. If utilizing multiple methodologies to verify the Facility capability, not all data points outlined in Section III, Item 6, 7, 8, or 9 need to be recorded.

2. Record any staged test or operational data in Attachment 3 (or a form containing the same information). If metering does not exist to measure specific values listed in Attachment 3, provide an engineering estimate and associated calculations. Refer to the associated labels depicted in the one-line diagram created in Section II, Item ~~4~~**3**. Record any additional data deemed necessary to perform engineering analysis per Note 1.

3. Staged testing or operating conditions should be maintained constant for a sufficient time in order to ensure that the applicable Facility can perform at that level of Real and Reactive Power during steady-state conditions.

4. All auxiliary equipment is expected to be in service for normal operation.

5. The ~~automatic~~**Facility** voltage ~~regulating~~**/Reactive power control** equipment is in ~~automatic voltage regulating~~**the normal** mode **of operation**.

6. For an applicable Facility with Real Power capability, **not meeting the criteria of Section III, Part 7, 8 or 9,** record measurements at the following four points:

   6.1. Maximum lagging Reactive Power at maximum Real Power until a limit is reached;[2]

   6.2. Maximum leading Reactive Power at maximum Real Power until a limit is reached;

   6.3. Maximum lagging Reactive Power at minimum Real Power until a limit is reached;

   6.4. Maximum leading Reactive Power at minimum Real Power until a limit is reached.

7. For an applicable Facility with no Real Power capability, record measurements at the following two points (one over-excited point and one under-excited point):

   7.1. Maximum lagging Reactive Power until a limit is reached;

   7.2. Maximum leading Reactive Power until a limit is reached.

8. For an applicable Facility with equal minimum and maximum Real Power output during normal operation, such as a nuclear unit, record measurements at the two points in Items 8.1 and 8.2 below. The Facility need only perform staged testing or provide operational data for Reactive Power at maximum Real Power output. If applicable, provide the theoretical Reactive Power capability at minimum Real Power output in accordance with Attachment 2.

   8.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached;

   8.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.

9. For variable generating resources, such as wind, solar, or run-of-river hydro, and non-variable generating resources, such as battery energy storage systems, staged testing or operational data should be recorded with at least 90 percent of the inverters/generators at a Facility on-line. If staged testing or operational data capture of a Facility cannot be accomplished while meeting the 90 percent inverter/generator threshold, document the reason(s) the threshold was not met and test to the full available capability at the time of the test. Maintain, as steady as practical, the maximum Real Power output that the resource can provide at the time of the verification. Record measurements at the two points in Items 9.1 and 9.2 below at the maximum Real Power output the variable resource can provide at the time of the staged test or operational data.

[2] In addition, consider steady state thermal or mechanical limitations of Facility equipment to determine whether it limits the Reactive Power capability during a staged test.

9.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached;

9.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.

Note 1: Under restrictive transmission system conditions, the data points obtained from a staged test or operational data might not duplicate the manufacturer supplied thermal capability curve (D-curve). When the applicable Facility's reactive capability is not fully demonstrated, perform a simulation or engineering analysis to determine expected capability under less restrictive system voltages. Even though this analysis will not verify the complete thermal capability curve (D-curve), it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.

MOD-025-3 Attachment 2 – BES Facility Capability Report

A completed report shall contain the following information at a minimum per Requirement R1 and R2:

- Section I: One-line diagram of the applicable Facility
- Section II: Composite capability curve
  - ~~•~~ **and associated** ~~Section III: Associated~~ PQ data table
- Section ~~IV~~**III**: Documentation showing the engineering basis and verification methodology

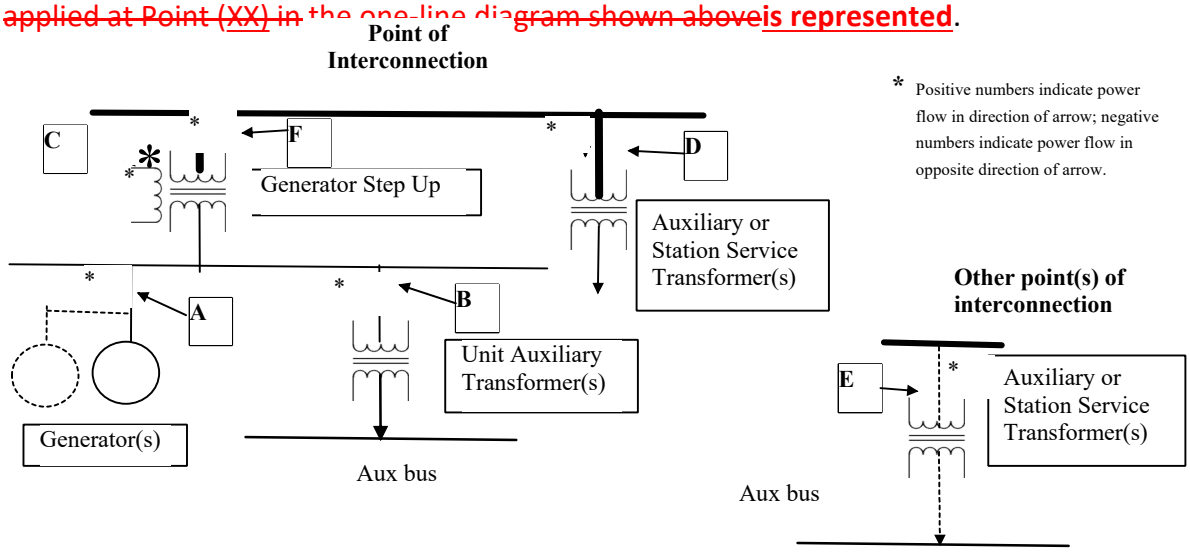
~~If the configuration of the applicable Facility does not lend itself to the use of the one-line diagram, capability curve, and data tables for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025-3, Attachment 1) is reported. An example report is provided below.~~

An example report is provided below. The report may vary based on the Facility being represented.

Company:	**Reported By (name):**
Plant:	**Unit No.:**
	Verification Date~~ of Verification~~:

Section I. Provide simplified one-line diagram ~~of~~**representing** the applicable Facility showing plant auxiliary Load connections.

Identify on the one-line diagram where the ~~The~~ composite capability curve ~~provided below is applied at Point (XX) in the one-line diagram shown above~~**is represented**.



Section II. Provide composite capability curve as defined in Attachment 1, Section II**, with associated PQ curve data table.**

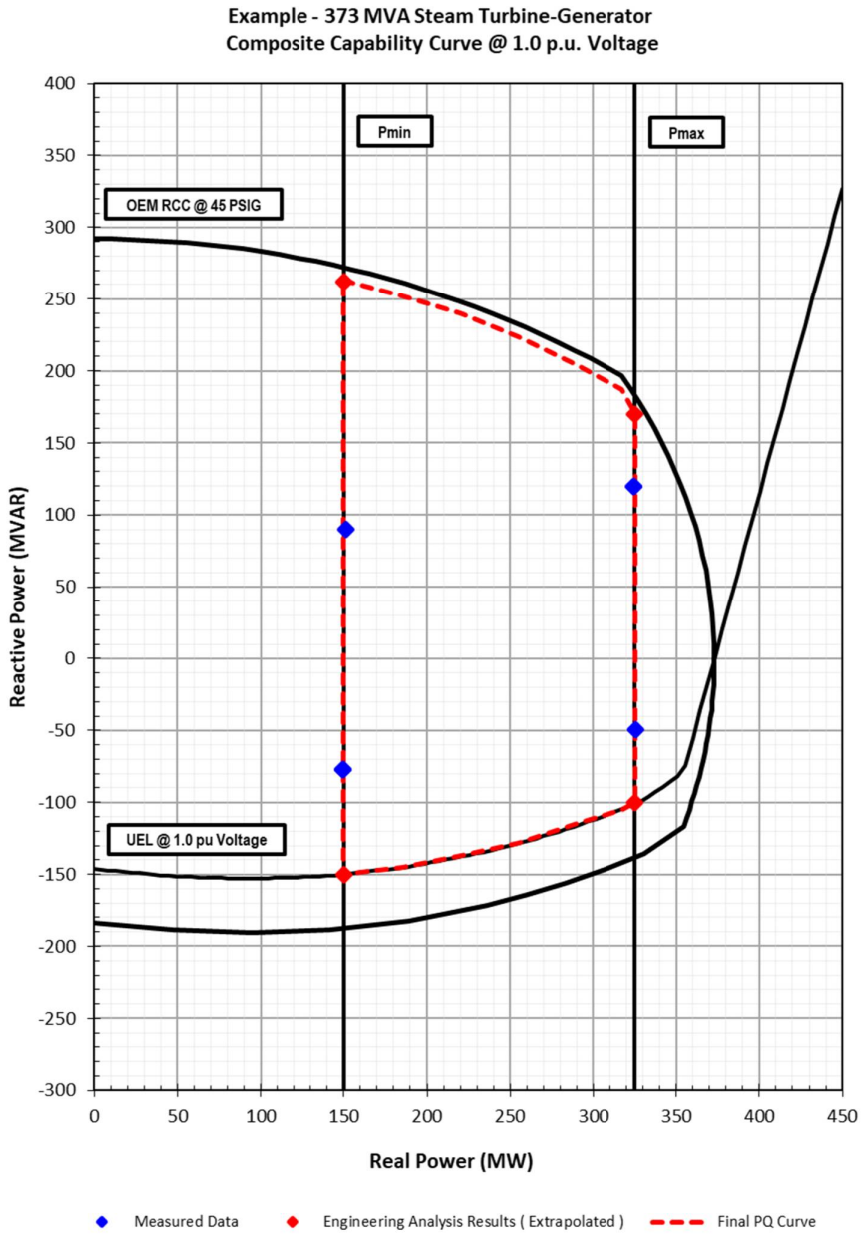


Figure 1: Example Composite Capability Curve for Synchronous Generator

~~Section III. Provided PQ curve data table associated with Figure 1.X composite capability curve~~

	P (MW)	Qmin (MVAr)	Qmax (MVAr)	Qmin Limit	Qmax Limit
Pmin	150.0	-150.0	263.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 20% of range	185.0	-145.0	252.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 40% of range	220.0	-137.0	240.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 60% of range	255.0	-128.0	224.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 80% of range	290.0	-115.0	204.0	UEL @ 1.0 Vterm	Ifd Rated
Breakpoint	317.1	-105.0	187.0	UEL @ 1.0 Vterm	Ifd Rated
Pmax	325.0	-100.0	170.0	UEL @ 1.0 Vterm	Ifd Rated

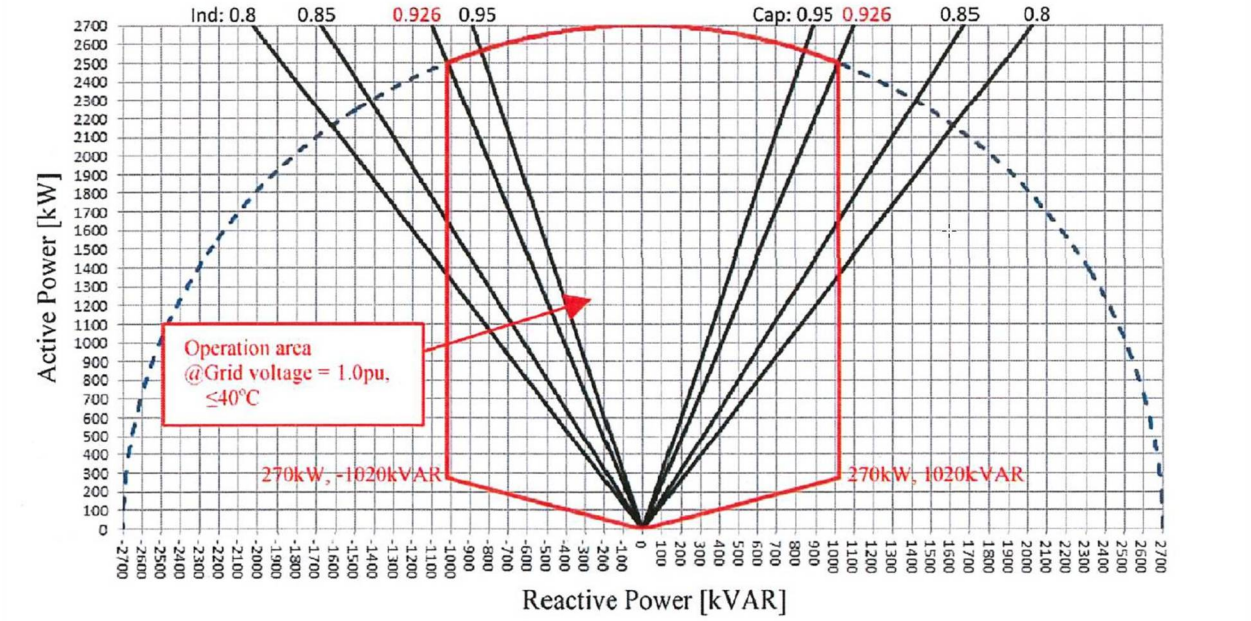


Figure 2: Example Composite Capability Curve for IBR ~~Facility~~Unit

PQ Curve Data Table (template)

Description	**Pmax** (MW)	**Qmax** (MVAR)	**Qmin** (MVAR)	**Qmax** Limiting Factor	**Qmin** Limiting Factor
Pmin					
Pmin + (0.20*Range) Range = (~~P~~$_{max}$**Pman** - Pmin)					
Pmin + (0.40*Range)					
Pmin + (0.60*Range)					
Pmin + (0.80*Range)					
Pmax					
Additional data points such as breakpoints are optional.					

1. Limiting factor: UEL/OEL, field current rating, distributed control system (DCS) limit, etc.

Section ~~IV~~**III**. Supplemental documentation of ~~engineering basis and~~ verification methodology**.**

MOD-~~025~~-025-3 Attachment 3

Data Table and Summary of Staged Test or Operational Data

Reference Attachment 2 one-line diagram measurement points and direction of flow arrows when recording Real and Reactive Power in data table. If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information is reported.

Company: **Reported By (name):**

Plant: **Unit No.:**

Check all that apply:

☐ Over-excited Maximum Load Reactive Power Verification

☐ Under-excited Maximum Load Reactive Power Verification

☐ Over-excited Minimum Load Reactive Power Verification

☐ Under-excited Minimum Load Reactive Power Verification

☐ Real Power Verification

☐ Staged Test Data

☐ Operational Data

Data Table for Recording Measurements

Point	Voltage	Real Power	Reactive Power	Comment
A	**kV**	**MW**	**Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B	**kV**	**MW**	**Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
C	**kV**	**MW**	**Mvar**	Sum multiple tertiary Loads, if any.

Identify calculated values, if any:				
D	**kV**	**MW**	**Mvar**	Sum multiple auxiliary and station service transformers.
Identify calculated values, if any:				
E	**kV**	**MW**	**Mvar**	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
F	**kV**	**MW**	**Mvar**	Net unit capability
Identify calculated values, if any:				

Summary of Test / Operational Data

- Date of Staged Test (or oldest Date of Operational Data): _____
- Start Time _____, End Time _____, Staged Test or Operational Data _____
- Transformer Voltage Ratio: GSU _____, Unit Aux _____, Station Aux _____, Other Aux _____
- Transformer Tap Setting: GSU _____, Unit Aux _____, Station Aux _____, Other Aux _____
- Transformer Impedance: GSU _____; Transformer X/R ratio: GSU _____
- Generator or Exciter Field Current (synchronous only): Start _____, End _____
- Ambient conditions at the end of the verification period:

  Air or inlet temperature: _____ Humidity: _____

  Cooling water temperature: _____ Stator temperature: _____

  Other data as applicable: _____
- Generator cooling gas pressure at time of test (if applicable) _____
- If the staged test/operational data did not reach capability curve (D-curve), describe the limiting factor.

Testing Remarks:

Summary report: Litera Compare for Word 11.3.1.3 Document comparison done on 4/20/2023 6:46:10 PM	
Style name: NERC Standards	
Intelligent Table Comparison: Active	
Original filename: MOD-025-3 Draft 1.0.docx	
Modified filename: MOD-025-3 Draft 2.0.docx	
Changes:	
Add	128
~~Delete~~	80
~~Move From~~	5
Move To	5
Table Insert	1
~~Table Delete~~	1
Table moves to	0
~~Table moves from~~	0
Embedded Graphics (Visio, ChemDraw, Images etc.)	0
Embedded Excel	0
Format changes	0
Total Changes:	220

Standard Development Timeline

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

Description of Current Draft

This is the ~~first~~second draft of the proposed standard being posted for a formal 45-day comment period and additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	March 4 – April 2, 2021

~~Anticipated Actions~~	~~Date~~
45-day formal or informal comment period with ballot	September – November 2022

Anticipated Actions	Date
45-day formal or informal comment period with additional ballot	~~February –~~ April – June 2023
10-day final ballot	~~May~~July 2023
Board adoption	August or December 2023

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

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

Term(s):

None.

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** PRC-019-3

3. **Purpose:** To verify coordination of generating unit or Facility voltage regulating controls, limit functions, equipment capabilities, and protective functions.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner

   4.2. Facilities: For the purpose of this standard, the term~~,~~ "applicable Facility" or "Facility" shall mean any one of the following:

   4.2.1 Individual generating resource identified through Inclusion I2 of the BES definition.

   4.2.2 Generating plant/Facility identified through Inclusion I2 of the BES definition.

   4.2.3 **Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the BES.**

   ~~**4.2.3** Dynamic reactive resources identified through Inclusion I5 of the BES definition with a gross (individual or aggregate) nameplate rating greater than 20 MVA including:~~

   ~~**4.2.3.1** Synchronous condenser.~~

   4.2.4 Inverter-based resource (IBR) generating plant/Facility ~~identified through Inclusion I4 of the BES definition,~~**greater than 75 MVA (gross nameplate rating)** including:

   4.2.4.1 Individual IBR units;

   4.2.4.2 Collector bus(es) and collector feeder(s);

   4.2.4.3 Static or dynamic reactive compensating devices;

   4.2.4.4 Main power transformer (MPT);[1]

[1] For the purpose of this standard, the MPT is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources.

4.2.4.5 Generator step-up (GSU) transformer(s);[2]

4.2.5 Any Blackstart Resource.

4.2.6 Facilities meeting an exclusion of the BES definition are exempt as an applicable Facility.

5. Effective Date: See the Implementation Plan for PRC-019-3.

B. Requirements and Measures

R1. ~~At a maximum of every six calendar years, each~~**Each** Generator Owner and Transmission Owner with applicable Facilities shall coordinate[3] the voltage regulating system controls, with the applicable equipment capabilities and settings of the applicable ~~protective~~**Protection System devices and** functions.[4] Equipment capabilities, control functions, and protective functions for the applicable Facilities include, but are not limited to those listed in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. For synchronous generators or synchronous condensers, assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items:

1.1.1. The in-service limiter functions~~[4]~~[5] are set to operate before the protective functions of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service protective functions are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities.

1.2. For IBR generating Facilities, assuming the voltage control mode[5] is enabled in the power plant controller and/or IBR unit(s)[6] and steady-state system operating conditions, verify the following coordination items:

1.2.1. The in-service control functions of the power plant controller are set to operate before the protective functions of the applicable Facilities in

[2] For the purpose of this standard, the GSU is the power transformer that steps up voltage from the individual IBR unit to the nominal collection system voltage for dispersed power producing resources.

[3] ~~As-left~~**Protection System as-left** settings shall be utilized in **compliance evidence for** a protection and control coordination study.

~~[4] A protective function includes an action performed by a Protection System device or an action performed by a control system that replicates the behavior of a Protection System device in order to mitigate the consequences of an event that exceeds equipment design basis.~~

[4] Limiter functions that are installed and activated on the generator or synchronous condenser.

[5] **For an IBR generating Facility without a voltage control mode capability, coordination should be performed assuming the normal operation control mode, and R1.2.1. and R1.2.2. would not apply.**

[6] IBR unit ~~includes the inverter, converter, or wind turbine generator~~**as defined by IEEE Std. 2800**.

order to avoid disconnecting any of the Facilities listed under Section 4.2.4 unnecessarily.

1.2.2. The in-service control functions of IBR unit(s) are set to operate before protective functions of the applicable Facilities in order to avoid disconnecting any of **the** Facilities listed under Section 4.2.4 unnecessarily.

1.2.3. The applicable in-service protective functions are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities.

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence such as a graphical representation(s) of coordination including a P-Q Diagram, R-X Diagram, Inverse Time Diagram, equivalent tables, steady-state calculations, dynamic simulation studies, or other evidence that it performed a coordination study as specified in Requirement R1. This evidence ~~should~~**will** include dated documentation that demonstrates the coordination was performed.

R2. Each Generator Owner and Transmission Owner shall perform the coordination described in Requirement R1 prior to implementation of systems, equipment, or settings changes that will affect the coordination described in Requirement R1~~; and update associated~~**. Associated** coordination documentation **shall be updated** within 90 calendar days after the return to in-service date. These possible systems, equipment**,** or settings changes include, but are not limited to, the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Voltage regulating settings or equipment changes;
- Protective function settings or component changes;
- IBR unit, synchronous generator**,** or synchronous condenser equipment capability changes;
- IBR unit, synchronous generator**,** or synchronous condenser step-up transformer changes;
- IBR unit control system firmware or settings changes; or
- ~~Power~~**IBR generating Facility power** plant controller firmware or settings changes.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination study required by the events listed in Requirement R2. This evidence ~~should~~**will** include dated documentation that demonstrates Requirement R2 has been met.

C. Compliance

1. **Compliance Monitoring Process**

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

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

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

   - The Generator Owner and Transmission owner shall keep data or evidence of Requirement R1 of the most recent coordination study.
   - The Generator Owner and Transmission Owner shall keep data or evidence of Requirement R2 of the most recent coordination study.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	~~The Generator Owner or Transmission Owner coordinated equipment capabilities, control functions, and protection specified in Requirement R1 between 6 years (72 months) and 76 months after the previous coordination.~~	~~The Generator Owner or Transmission Owner coordinated equipment capabilities, control functions, and protection specified in Requirement R1 between 77 and 81 months after the previous coordination.~~	~~The Generator Owner or Transmission Owner coordinated equipment capabilities, control functions, and protection specified in Requirement R1 between 82 and 86 months after the previous coordination.~~	~~The Generator Owner or Transmission Owner coordinated equipment capabilities, control functions, and protection specified in Requirement R1 more than 86 months after the previous coordination.~~ ~~OR~~ The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection as specified in Requirement R1.
R2.	The Generator Owner or Transmission Owner updated associated coordination documentation as specified in Requirement R2 between 91 and 120 calendar days after return to in-service date.	The Generator Owner or Transmission Owner updated associated coordination documentation as specified in Requirement R2 between 121 and 150 calendar days after return to in-service date.	The Generator Owner or Transmission Owner updated associated coordination documentation as specified in Requirement R2 between 151 and 180 calendar days after return to in-service date.	The Generator Owner or Transmission Owner failed to update associated coordination documentation as specified in Requirement R2 within ~~151~~**181** calendar days after return to in-service date. OR The Generator Owner or Transmission Owner failed to

[Link-to-previous setting changed from on in original to off in modified.].

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				coordinate equipment capabilities, limiters, and protection specified in Requirement R1 prior to ~~the~~ implementing a change in equipment or settings that affected the coordination.

D. Regional Variances

None.

E. Associated Documents

"Underexcited Operation of Turbo Generators", AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

""Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

"Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

"IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

"IEEE C37.106 IEEE Guide for Abnormal Frequency Protection for Power Generating Plants"

"IEEE Std 2800-2022 IEEE Standard for Interconnection and Interoperability of Invert-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems"

[Link-to-previous setting changed from on in original to off in modified.].

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
1	March 20, 2014	FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-019-2	Modifications to adjust the applicability to owners of dispersed generation resources.
3	TBD	Adopted by NERC Board of Trustees	Standard revised in Project 2021-01

Attachment 1: Equipment Capabilities, Types of Limiters, and Protective Functions

NOTE: This standard does not require the installation or activation of any of the limiter or protection functions for synchronous generation or IBR.

A. Synchronous generation equipment capabilities, control functions, and protective functions, which shall be coordinated if enabled, include but are not limited to:

- Synchronous generator/condenser reactive capabilities;
- Field over-excitation limiter and associated protective function;
- Field under-excitation limiter and associated protective function;
- Volts per hertz limiter and associated protective function;
- Stator over-voltage protection system settings;
- Synchronous generator/condenser and transformer volts per hertz capability;
- Time vs. field current or time vs. stator current; and
- Distributed control system (DCS) voltage/VAR limit settings.

B. IBR generating Facility equipment capabilities, control functions, and protective functions, which shall be coordinated if enabled, include but are not limited to:

- Transformer overvoltage protective function **and associated control function**;
- Transformer undervoltage protective function **and associated control function**;
- Transformer volts per hertz capability ~~and~~ protective function **and associated control function**;
- Collector bus overvoltage protective function **and associated control function**;
- Collector bus undervoltage protective function **and associated control function**;
- Reactive compensating devices voltage control functions **and associated control function**;
- Reactive compensating devices voltage protective function **and associated control function**;
- Collector feeder phase overvoltage protective function **and associated control function**;
- Collector feeder phase undervoltage protective function **and associated control function**;
- Collector feeder overcurrent limiter~~;~~
- ~~•~~ **and associated** ~~IBR unit phase lock loop~~ protective function;

-
- IBR unit overcurrent limiter **and associated protective function**;
- IBR unit momentary cessation (cease current injection) protective function;
- IBR unit phase overvoltage protective function **and associated control function**;
- IBR unit phase undervoltage protective function **and associated control function**; and
- IBR unit phase overcurrent protective function **and associated control function**.

Summary report: Litera Compare for Word 11.3.1.3 Document comparison done on 4/20/2023 7:05:12 PM	
Style name: NERC Standards	
Intelligent Table Comparison: Active	
Original filename: PRC-019-3 Draft 1.0.docx	
Modified filename: PRC-019-3 Draft 2.0.docx	
Changes:	
Add	58
~~Delete~~	44
~~Move From~~	0
Move To	0
Table Insert	1
~~Table Delete~~	1
Table moves to	0
~~Table moves from~~	0
Embedded Graphics (Visio, ChemDraw, Images etc.)	0
Embedded Excel	0
Format changes	0
Total Changes:	104

Standard Development Timeline

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

Description of Current Draft

This is the ~~first~~ third draft of the proposed standard for a formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	March 3 – April 6, 2022
SAR posted for comment	April 14 –May 13, 2021

Anticipated Actions	Date
45-day formal comment period with ballot	October 31, 2022 – January 13, 2023
45-day formal comment period with additional ballot	May 10 – June 23, 2023
45-day formal comment period with additional ballot	September 22 – November 6, 2023
10-day final ballot	TBD
Board adoption	TBD

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

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

Term(s):

None

A. Introduction

1. **Title:** Generator Operation for Maintaining Network Voltage Schedules

2. **Number:** VAR-002-5

3. **Purpose:** To ensure Bulk Electric System generating resource(s) ~~and dispersed power producing resources~~ provide reactive support and voltage control, within generating ~~Facility~~ resource capabilities, in order to protect equipment, and maintain Reliable Operation of the Interconnection.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Operator

   4.1.2. Generator Owner

   ~~**4.2. Facilities:** For the purpose of this standard, "applicable Facility" will mean any generating Facility as defined by the Bulk Electric System.~~

5. **Effective Date:** See Implementation Plan for VAR-002-5.

B. Requirements and Measures

R1. The Generator Operator shall operate each ~~applicable Facility~~generating resource(s) connected to the interconnected ~~transmission~~ Transmission ~~system~~ System in the automatic voltage control mode (with its automatic voltage regulator (AVR~~) or volt/VAR controller(s)~~[1] in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the ~~applicable Facility~~generating resource(s) is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the ~~applicable Facility~~generating resource(s) is being operated in start-up[2], shutdown[3], or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the ~~applicable Facility~~generating resource(s) is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate ~~an~~ a ~~applicable Facility~~generating resource(s) in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If ~~an~~ a ~~applicable Facility~~generating resource(s) is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If ~~an~~ a ~~applicable Facility~~generating resource(s) is exempted from automatic voltage control mode (with its AVR ~~or volt/VAR controller(s)~~ in service and controlling voltage), the Generator Operator will maintain evidence of an exception.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the ~~applicable Facility~~generating resource(s) voltage or Reactive Power schedule[4] (within each generating Facility's capabilities[5]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or

---

[1] For dispersed power producing resources identified through inclusion I4 of the Bulk Electric System definition, the automatic voltage regulator (AVR) refers to the voltage & reactive power control system controlling and coordinating plant voltage.~~For an aggregate generating plant, the volt/VAR controller includes the voltage & reactive power control system controlling and coordinating plant voltage.~~

[2] Start-up is deemed to have ended when the ~~applicable Facility~~generating resource(s) is ramped up to its minimum continuously sustainable Load and the ~~applicable Facility~~generating resource(s) is prepared for continuous operation.

[3] Shutdown is deemed to begin when the ~~applicable Facility~~generating resource(s) is ramped down to its minimum continuously sustainable Load and the ~~applicable Facility~~generating resource(s) is prepared to go offline.

[4] The voltage or Reactive Power schedule is a target value with a tolerance band, or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.

[5] Generating ~~Facility~~ resource(s) capability may be established by test or other means and may not be sufficient at times to pull the System voltage within the schedule tolerance band. Also, when ~~an~~ a ~~applicable Facility~~generating resource(s) is operating in manual control, Reactive Power capability may change, based on stability considerations.

Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When ~~an~~ a ~~applicable Facility~~generating resource(s)'s AVR ~~or volt/VAR controller(s)~~ is out of service or the ~~generator~~ applicable Facility does not have an AVR, the Generator Operator shall use an alternative method to control the ~~generator~~ applicable Facility reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator or if no other method of control is available, notify the Transmission Operator as soon as becoming aware of the condition.

2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

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

M2. In order to identify when ~~an~~ a ~~applicable Facility~~generating resource(s) is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator will have evidence to show that the ~~applicable Facility~~generating resource(s) maintained the voltage or Reactive Power schedule provided by the Transmission Operator or will have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator.

Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when ~~an~~ a ~~applicable Facility~~generating resource(s)'s AVR ~~or volt/VAR controller(s)~~ is out of service or the ~~applicable Facility~~generating resource(s) does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator or evidence of notification to the Transmission Operator if no other method of control is available.

For Part 2.2, the Generator Operator will have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator will demonstrate the methodology for converting the scheduled voltage to the voltage point being monitored by the Generator Operator.

R3. Each Generator Operator shall notify its associated Transmission Operator, in a mutually-~~agreeable~~ agreed communication ~~criteria~~[6] method, within 30 minutes of status change of its AVR or within 30 minutes of becoming aware ~~its associated Transmission Operator~~ of ~~a~~ an ~~status or~~ unexpected functionality change of ~~applicable~~ its AVR, ~~volt/VAR controller(s),~~ power system stabilizer, or alternative voltage controlling device. ~~which degrades or restores from degradation its ability to automatically control voltage. Status or functionality change notifications shall be made within 30 minutes of such change.~~ If the status or functionality has been restored within 30 minutes, then the Generator Operator is not required to notify the Transmission Operator of the ~~status~~ change. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. ~~The~~ Each Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of status change of its AVR or within 30 minutes of becoming aware of an unexpected functionality change ~~within 30 minutes of the change~~ identified in Requirement R3 ~~and evidence of the mutually agreeable criteria such as any of the following: emails, voltage schedule documentation, or reliability data specification~~. If the status or functionality change has been restored within the first 30 minutes, no notification is necessary.

R4. Each Generator Operator shall notify its associated Transmission Operator, in a mutually-agreeable communication ~~criteria~~method, ~~its associated Transmission Operator~~ within 30 minutes of becoming aware of a ~~-~~reactive capability change ~~in reactive capability that degrades or restores from degradation and exceeds the threshold for notification~~ due to factors other than those specified in Requirement R3 at the generating resource(s). Where the Transmission Operator has specified a reactive capability threshold, the Generator Operator shall report reactive capability changes that create degradation or restores from degradation. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. ~~The~~ Each Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary. ~~The Generator Operator will provide evidence of coordination, as necessary, with the Transmission Operator to identify a mutually- agreeable criteria, such as any of the following: emails, voltage schedule documentation, or reliability data specification.~~

R5. The Generator Owner for each ~~applicable Facility~~generating resource(s) shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

5.1. For generator step-up[6] and auxiliary transformers[7] with primary voltages equal

[6] Generator step-up and auxiliary transformers would be owned and maintained by the Generator Owner.

[7] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement

to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available tap ranges.

5.1.3. Impedance data.

M5. The Generator Owner for each ~~applicable Facility~~generating resource(s) shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its

[6] ~~Mutually-agreeable format for VAR-002-5 - notification should include the communication method (e.g., voice, data, email, etc.) and the threshold of degradation an applicable Facility.~~

(Requirement R5 and its subparts) applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

step-up and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

R6. After consultation with the Transmission Operator regarding necessary generator owned step-up transformer tap changes, the Generator Owner for each ~~applicable Facility~~generating resource(s) shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an Equipment Rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

6.1. If the applicable Generator Owner for each ~~applicable Facility~~generating resource(s) cannot comply with the Transmission Operator's specifications, the Generator Owner for each ~~applicable Facility~~generating resource(s) shall notify the Transmission Operator and shall provide the technical justification.

M6. The ~~applicable Facility~~generating resource(s) shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The ~~applicable Facility~~generating resource(s) shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

C. Compliance

1. Compliance Monitoring Process

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

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

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

The Generator Owner for each ~~applicable Facility~~generating resource(s) shall keep its latest version of documentation on its step-up and auxiliary transformers.

~~The Generator Operator for each applicable Facility shall keep its latest version of documentation on its step-up and auxiliary transformers.~~

The Generator Operator for each ~~applicable Facility~~generating resource(s) shall retain evidence of Requirements R1, R2, R3 and R4 for three calendar years.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator and dispersed power producing resource connected to the interconnected Transmission System in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.
R2.	N/A	N/A	The Generator Operator did maintain voltage or Reactive Power as instructed by the Transmission Operator. AND, The Generator Operator did make the necessary notifications required by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator. AND The Generator Operator did not make the necessary notifications required by the Transmission Operator.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			BUT The Generator Operator did not have a conversion methodology when it monitored voltage at a location different from the schedule provided by the Transmission Operator.	OR The Generator Operator did not have an operating AVR ~~or volt/VAR controller(s)~~, and did not use an alternative method for controlling voltage or provide notification to the Transmission Operator if no alternative method of control was available. OR The Generator Operator did not modify voltage when directed, and did not provide any explanation.
R3.	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status or functionality change.
R4.	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				of the capability change.
R5.	N/A	N/A	The Generator Owner for each ~~applicable Facility~~generating resource(s) failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner for each ~~applicable Facility~~generating resource(s) failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6.	N/A	N/A	N/A	The Generator Owner for each ~~applicable Facility~~generating resource(s) did not ensure the tap changes were made according to the Transmission Operator's specifications. OR The Generator Owner for each ~~applicable Facility~~generating resource(s) failed to perform the tap changes, and the Generator Owner for each ~~applicable Facility~~generating resource(s) did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007.	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009.	Revised
2b	4/16/2013	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR001-2, R4. FERC Order issued approving VAR002-2b.	Revised
3	5/5/2014	Revised under Project 2013-04 to address outstanding Order 693 directives.	Revised
3	5/7/2014	Adopted by NERC Board of Trustees.	
3	8/1/2014	Approved by FERC in docket RD14-11-000.	
4	8/27/2014	Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources.	Revised
4	11/13/2014	Adopted by NERC Board of Trustees.	
4	5/29/2015	FERC Letter Order in Docket No. RD15- 3-000 approving VAR-002-4.	
4.1	6/14/2017	Project 2016-EPR-02 errata recommendations.	Errata
4.1	8/10/2017	Adopted by the NERC Board of Trustees.	Errata
4.1	9/26/2017	FERC Letter Order issued approving VAR-002-4.1 RD17-7-000.	
5	TBD	Revised under Project 2021-02 to clarify applicability of Requirements to BES dispersed power producing resources and to address recommendations from Project 2016-EPR-02.	Revised

Standard Development Timeline

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

Description of Current Draft

This is the initial draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with ballot	September – November 2023

Anticipated Actions	Date
Final Ballot TOCC	December 2023
Board adoption	December 2023

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):

Control Center - One or more ~~facilities~~ rooms where a responsible entity hosts ~~hosting~~ operating personnel ~~that~~ to monitor and control the Bulk Electric System (BES) in real-time, as described below, ~~to perform the reliability tasks,~~ including any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time. Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units.~~their associated data centers, of:~~

1) Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;~~,~~

2) Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;~~,~~

3) Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for ~~t~~Transmission Facilities at two or more locations;

4) ~~,~~Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time; or

5) Operating personnel of a Generator Operator who have the capability to electronically control ~~for~~ generation Facilities at two or more locations in real-time.

A. Introduction

1. Title: Cyber Security — Bulk Electric System (BES) Cyber System Categorization

2. Number: CIP-002-~~5.1a~~Y

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 (RAS) where the ~~Special Protection System or Remedial Action Scheme~~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

~~**Interchange Coordinator or Interchange Authority**~~

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. ~~Each Special Protection System or Remedial Action Scheme~~RAS where the ~~Special Protection System or Remedial Action Scheme~~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-002-~~5.1a~~Y:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates: See "Project 2021-03 CIP-002 Transmission Owners Control Centers Implementation Plan"

~~1. **24 Months Minimum** – CIP-002-5.1a shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~2. In those jurisdictions where no regulatory approval is required CIP-002-5.1a shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

~~**6. Background:**~~

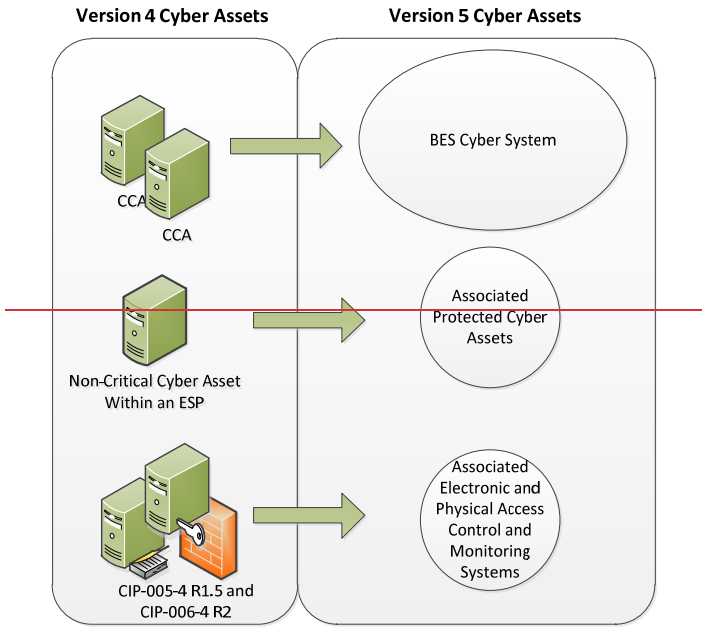
~~This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation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

~~Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an "or," and numbered items are items that are linked with an "and."~~

~~Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~**BES Cyber Systems**~~

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



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

~~Another reason for using the 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 ~~p~~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~~RAS that support the reliable operation of the ~~Bulk Electric System~~BES; 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:

"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. ~~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 period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA 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~~applicable 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~~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~~

~~1.4. Additional Compliance Information~~

- ~~None~~

~~2. Table of Compliance Elements~~ Violation Severity Levels

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R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-~~5.1a~~Y)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	High	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities -with more than a total of 100 high and medium impact BES Cyber

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-~~5.1a~~Y)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber	For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly	For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber ~~Assets~~Systems, more than 10 but less than or equal to 15 identified BES Cyber ~~Assets~~Systems have not been categorized or have been	Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities -with more than a total of 100 high and medium impact BES Cyber

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-~~5.1a~~Y)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Systems, five percent or fewer high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.	categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10- high or medium BES Cyber Systems have not been identified.	incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15- high or medium BES Cyber Systems have not been identified.	Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-~~5.1a~~Y)			
			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-002-5.1a~~Y ~~-~~ Attachment 1 – Impact Rating Criteria

~~Impact Rating Criteria~~

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.

1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are ~~those~~each discrete 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~~each discrete 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

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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.

Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:

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~~ , operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H~~)~~) above~~.~~, with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per characteristic" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

Exclusion:
BES Transmission Lines monitored and controlled by the Control Center or backup Control Center may be excluded from the "aggregate weighted value" calculation if they are part of a local system that is operated at less than 300kV, where the net export from the local system does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The net export is based on the hourly integrated values for the most recent 12-month period.

~~2.12.~~**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~~RAS that support the reliable operation of the ~~Bulk Electric System~~BES.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

~~Guidelines and Technical Basis~~

~~Section 4 – Scope of Applicability of the CIP Cyber Security Standards~~

~~Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.~~

~~Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.~~

~~Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.~~

~~For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1a. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.~~

~~CIP-002-5.1a~~

~~CIP-002-5.1a requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."~~

~~The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber~~

~~Systems that would be subject to CIP-002-5.1a. 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-002-5.1a, 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.~~

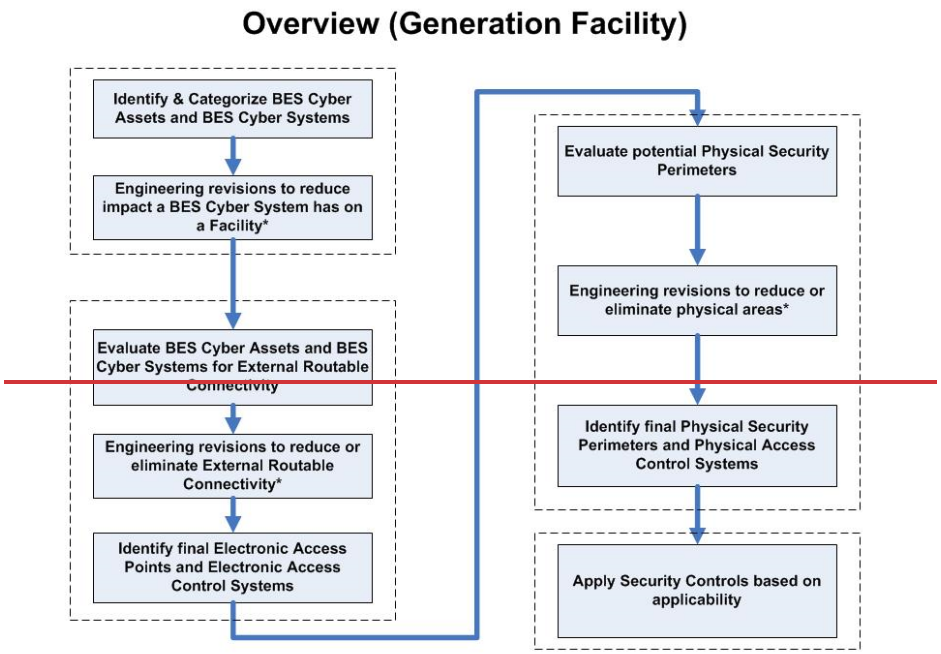
~~Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific 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.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
Y	TBD		

Appendix 1

Requirement Number and Text of Requirement
CIP-002-5.1, Requirement R1 R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: i. Control Centers and backup Control Centers; ii. Transmission stations and substations; iii. Generation resources; iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements; v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above. 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset; 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required). Attachment 1, Criterion 2.1 2. Medium Impact Rating (M) Each BES Cyber System, not included in Section 1 above, associated with any of the following: 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase "shared BES Cyber Systems."

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase "shared BES Cyber Systems" means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase "shared BES Cyber Systems," means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states "Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2…" Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states "*Each BES Cyber System*…associated with any of the following [criteria]." (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that "[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System." The Background section also provides:

> The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

~~Question 2: Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?~~

~~The phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple generation units.~~

~~The use of the term "shared" is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:~~

> ~~Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." For criterion 2.2: "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.~~

~~Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?~~

~~The phrase applies to each discrete BES Cyber System.~~

Standard Development Timeline

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

Description of Current Draft

This is the second draft of the proposed standard for a formal 35-day ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
45-day formal comment period with ballot	6/5/23 – 7/20/23
35-day formal or informal comment period with additional ballot	October – November 2023

Anticipated Actions	Date
10-day final ballot	January 2024
Board adoption	February 2024

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):

Generator Cold Weather Critical Component ~~–~~ Any generating unit component and/or system, or associated ~~fixed fuel supply component~~Fixed Fuel Supply Component, that is under the Generator Owner's control, and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event. This definition excludes any component or associated Fixed Fuel Supply Component located inside a permanent building with a heating source that regularly maintains the space at a temperature above 32 degrees Fahrenheit (0 degrees Celsius).

~~**Extreme Cold Weather Temperature** – The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.~~

Fixed Fuel Supply Component – Non-mobile equipment that supports the reliable delivery of fuel to the generating unit and under the control of the Generator Owner at a plant site. Gaseous, liquid, or solid fuel handling components that are installed on site as fixed parts of the fuel delivery system that are under the Generator Owner's control are included. Mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location are excluded.

Generator Cold Weather Reliability Event ~~–~~ One of the following events for which the apparent cause(s) is due to freezing of equipment or impacts of freezing precipitation (e.g., sleet, snow, ice, and freezing rain) on equipment within the Generator Owner's control, and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

(1) a forced derate of more than 10% of the total capacity of the unit ~~and exceeding~~, but not less than 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage.

Generator Cold Weather Constraint – Any condition that would preclude a Generator Owner, using good utility practice,[1] from implementing freeze protection measures on one or more Generator Cold Weather Critical Components.

Previously Approved Terms

This section includes previously approved terms from Phase 1. It is included to help with drafting and the posting of EOP-012-2.

Extreme Cold Weather Temperature – The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.

[1] The phrase "good utility practice" is being used in its common understanding. More information on this can be found in the Technical Rationale. This footnote is for information purposes only in the posting and will not be included in the term included in the NERC Glossary of Terms.

A. Introduction

1. **Title:** **Extreme Cold Weather Preparedness and Operations**

2. **Number:** EOP-012-~~1~~2

3. **Purpose:** To address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its applicable generating units.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Generator Operator

   4.2. Facilities:

   4.2.1. Bulk Electric System (BES) generating units. For purposes of this standard, the term "generating unit" subject to these requirements refers to the following Bulk Electric System (BES) resources:

   ~~**4.2.1.1** A Bulk Electric System generating unit that commits or is obligated to serve a Balancing Authority load pursuant to a tariff obligation, state requirement as defined by the relevant electric regulatory authority, or other contractual arrangement, rule, or regulation, for a continuous run of four hours or more at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius); or~~

   4.2.1.1. A Bulk Electric System generating resource identified in the BES definition, inclusion I2 and I4; or

   ~~**4.2.1.2**~~ **4.2.1.2.** A Blackstart Resource

   ~~**4.2.2 Exemptions:**~~

   ~~Any Bulk Electric System generating unit included under Section 4.2.1 above that has a calculated Extreme Cold Weather Temperature exceeding 32 degrees Fahrenheit (zero degrees Celsius) under Requirement R3 Part 3.1 and as part of~~ , identified in the ~~required five-year review in Requirement R4 Part 4.1 is exempt from further requirements in this standard~~BES definition, inclusion I3.

   ~~**4.2.2.1** A Bulk Electric System generating unit that is not committed or obligated to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours, but is called upon to operate for more than four hours in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius).~~

5. **Effective Date:** See Implementation Plan for Project 2021-07~~.~~ Phase 2.

B. Requirements and Measures

R1. ~~For~~At least once every five calendar years, each Generator Owner shall, for each of its applicable generating unit(s): [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]

1.1. Calculate the Extreme Cold Weather Temperature for each of its applicable unit(s) and identify the calculation date and source of temperature data; and

1.1.1. If the re-calculated Extreme Cold Weather Temperature is lower than the previous Extreme Cold Weather Temperature, the entity shall review and update its cold weather preparedness plan under Requirement R4 within six (6) months of the recalculation. If new corrective actions are needed to provide the required operational capability under Requirement R3, the entity shall develop a Corrective Action Plan within 6 months of the recalculation.

1.2. Identify generating unit(s) cold weather data, to include:

1.2.1. Generating unit(s) operating limitations in cold weather to include:

1.2.1.1. Capability and availability;

1.2.1.2. Fuel supply and inventory concerns;

1.2.1.3. Fuel switching capabilities; and

1.2.1.4. Environmental constraints.

~~)~~**1.2.2.** Generating unit(s) minimum:

- Design temperature and if available, the concurrent wind speed and precipitation;
- Historical operating temperature at least one hour in duration, and if available, the concurrent wind speed and precipitation; or
- Current cold weather performance temperature determined by an engineering analysis, which includes the concurrent wind speed and precipitation.

M1. Each Generator Owner will have evidence documenting its Extreme Cold Weather Temperature calculation and design information, operating data, or engineering analysis that supports its generating unit minimum temperature.

~~R1.~~R2. Applicable to generating units with a commercial operation date ~~subsequent to [Effective Date of this requirement], the Generator Owner~~on or after October 1, 2027: Each Generator Owner, for each generating unit that has a calculated Extreme Cold Weather Temperature at or below 32 degrees Fahrenheit (zero degrees Celsius) as

determined in Requirement R1, and that self-commits or is required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius),[2] shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

- ~~•~~ Implement freeze protection measures to protect Generator Cold Weather Critical Components that provide the capability to operate ~~for~~at the unit(s)' Extreme Cold Weather Temperature with sustained concurrent twenty (20) mph wind speed for (i) a period of not less than twelve (12) continuous hours~~ at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components;~~, or

  - ~~Explain in a declaration any technical, commercial, or~~ (ii) the maximum operational ~~constraints, as defined by the Generator Owner, that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for~~ duration for intermittent energy resources if less than twelve (12) continuous hours~~ at the documented Extreme Cold Weather Temperature.~~; or

~~**M1.** Each Generator Owner will have dated evidence that demonstrates it has the capability to operate in accordance with Requirement R1. Acceptable evidence may include, but is not limited to, the following (electronic or hardcopy format): Documentation of cold weather preparedness plan, documentation of design features, any declaration that contains dated documentation to support constraints identified by the Generator Owner.~~

- ~~For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s)~~Develop a Corrective Action Plan(s) to add new or modify existing freeze protection measures ~~as needed~~ to provide the capability to operate ~~for a period of not less than one (1) hour~~ at the unit(s)' Extreme Cold Weather Temperature~~. Generating unit(s) that are not capable of operating~~ with a sustained concurrent twenty (20) mph wind speed for (i) a period of not less than twelve (12) continuous hours, or (ii) the maximum operational duration for ~~one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]~~intermittent energy resources if less than twelve (12) continuous hours.

[2] Generating unit(s) that do not self-commit or are not required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), but may be called upon to operate in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), are exempt from this requirement.

M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a ~~CAP~~Corrective Action Plan for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating ~~units~~unit(s) minimum temperature per Part ~~3.5~~1.2.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, ~~cold weather preparedness plan, and CAP~~and Corrective Action Plan(s).

R3. Applicable to generating unit(s) in commercial operation prior to October 1, 2027: Each Generator Owner, for each generating unit that has a calculated Extreme Cold Weather Temperature at or below 32 degrees Fahrenheit (zero degrees Celsius) as determined in Requirement R1, and that self-commits or is required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius),[3] shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

- Implement freeze protection measures that provide the capability to operate at the unit(s)' Extreme Cold Weather Temperature; or
- Develop a Corrective Action Plan to add new or modify existing freeze protection measures to provide the capability to operate at the unit(s)' Extreme Cold Weather Temperature.

M3. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R3, or it has developed a Corrective Action Plan for the identified issues. Acceptable evidence may include, but is not limited to, the following (electronic or hardcopy format): Identification of generating unit(s) minimum temperature per Part 1.2.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, and Corrective Action Plan(s).

R4. Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: *[Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

4.1. The lowest calculated Extreme Cold Weather Temperature for ~~their~~each unit~~(s) including the calculation date and source of temperature~~, as determined in Requirement R1;[4]

4.2. The generating unit cold weather data~~;~~, as determined in Requirement R1.2;

[3] Generating unit(s) that do not self-commit or are not required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), but may be called upon to operate in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), are exempt from this requirement.

[4] Generator Owners shall include the lowest calculated Extreme Cold Weather Temperature for the unit, even where subsequent periodic re-calculations under Requirement R1 Part 1.1 cause an increase in the Extreme Cold Weather Temperature.

4.3. Documentation identifying ~~the~~ Generator Cold Weather Critical Components;

4.4. Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which ~~may include~~includes measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain); and

4.5. Annual inspection and maintenance of generating unit(s) freeze protection measures~~; and~~.

~~**3.1** Generating unit(s) cold weather data, to include:~~

~~**3.1.1** Generating unit(s) operating limitations in cold weather to include:~~

M4. ~~Capability and availability;~~

~~Fuel supply and inventory concerns;~~

~~Fuel switching capabilities; and~~

~~Environmental constraints.~~

~~**3.1.2** Generating unit(s) minimum:~~

- ~~Design temperature;~~
- ~~Historical operating temperature; or~~
- ~~Current cold weather performance temperature determined by an engineering analysis.~~

Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement ~~R3~~R4. Examples of documentation to demonstrate inspections and maintenance have been completed may include, but are not limited to, completed work order(s) from the Generator Owner's work management system and/or freeze protection checklists identifying the measures inspected and maintained.

~~**R3.** Once every five calendar years, each Generator Owner shall for each generating unit: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*~~

~~**4.1** Calculate the Extreme Cold Weather Temperature, and update the cold weather preparedness plan if this temperature is now lower than the previous lowest calculation;~~

~~**4.2** Review its documented generating unit(s) minimum temperature contained within its cold weather preparedness plan(s), pursuant to Part 3.5.2; and~~

~~**4.3** Review whether its generating units have the freeze protection measures required to operate at the Extreme Cold Weather Temperature pursuant to R1 or R2 as applicable, and if not develop a CAP for the identified issues, including~~

~~identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.~~

~~**M2.** Each Generator Owner will have dated, documented evidence that it reviewed temperature data and updated its cold weather preparedness plan(s) in accordance with Requirement R4.~~

R5. Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement ~~R3~~R4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

M5. Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed annual training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R5.

R6. Each Generator Owner ~~that owns a~~ shall, for each generating unit that has a calculated Extreme Cold Weather Temperature at or below 32 degrees Fahrenheit (zero degrees Celsius) as determined in Requirement R1 and that self-commits or is required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius),[5] develop a Corrective Action Plan when the generating unit experiences a Generator Cold Weather Reliability Event. The Corrective Action Plan shall ~~develop a CAP,~~be developed within 150 days or by July 1, whichever is earlier, ~~that contains~~and contain at a minimum: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1. A summary of the identified cause(s) for the Generator Cold Weather Reliability Event, where applicable, and any relevant associated data;

6.2. A review of applicability to similar equipment at ~~other~~ generating units owned by the Generator Owner; and

6.3. An identification of ~~any temporary~~ operating limitations or impacts to the cold weather preparedness plan~~,~~ that would apply until execution of the corrective action(s) identified in the ~~CAP~~Corrective Action Plan.

M6. Each Generator Owner will have documented evidence that it developed a ~~CAP~~Corrective Action Plan following a Cold Weather Reliability Event at an applicable

[5] Generating unit(s) that do not self-commit or are not required to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), but may be called upon to operate in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), are exempt from this requirement.

unit in accordance with Requirement R6. Acceptable evidence may include, but is not limited to, the following dated documentation (electronic or hardcopy format): ~~CAP~~Corrective Action Plan(s) and updated cold weather preparedness plan(s) where indicated as needed by the ~~CAP~~Corrective Action Plan.

R7. Each Generator Owner~~-~~, for each Corrective Action Plan developed pursuant to Requirements R1, R2, R3, or R6, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1. Include a timetable for implementing the selected corrective action(s) that shall:

7.1.1. List the action(s) which address(es) existing equipment or freeze protection measures, if any, to be completed within 24 calendar months of completing development of the Corrective Action Plan;

7.1.2. List the action(s) which require(s) new equipment or freeze protection measures, if any, to be completed within 48 calendar months of completing development of the Corrective Action Plan;

7.1.3. List the updates to the cold weather preparedness plan required under Requirement R4 to identify the updates or additions to the Generator Cold Weather Critical Components and their freeze protection measures; and

7.1.4. For one or more Corrective Action Plan(s) that address multiple units in a fleet, the Corrective Action Plan shall stagger implementation across those generating units.

7.2. Implement ~~each CAP developed pursuant to Requirements R2, R4, or R6, or explain~~the Corrective Action Plan in accordance with the specified timetables in Requirement R7 Part 7.1;

7.3. Update the Corrective Action Plan, with justification, if corrective action(s) change or timetable(s) exceed the timelines in Requirement R7 Part 7.1; and

7.4. Document in a declaration ~~why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by~~, with justification, any Generator Cold Weather Constraint that precludes the Generator Owner from implementing actions contained within the Corrective Action Plan.

~~**7.2** Update each CAP if actions or timetables change, until completed.~~

M7. Each Generator Owner shall have dated evidence that demonstrates it implemented each ~~CAP~~Corrective Action Plan, including updating actions or timetables, or has explained in a declaration why corrective actions are not being implemented in accordance with Requirement ~~R7~~R8. Acceptable evidence may include, but is not limited to, the following dated documentation (electronic or hardcopy format): records that document the implementation of each ~~CAP~~Corrective Action Plan and the completion of actions for each ~~CAP~~Corrective Action Plan including revision history of each ~~CAP~~Corrective Action Plan. Evidence may also include work management

program records, work orders, and maintenance records. Any declaration shall contain dated documentation to support constraints identified by the Generator Owner.

R8. Each Generator Owner that creates a Generator Cold Weather Constraint declaration shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. Perform an annual review and update the Generator Cold Weather Constraint declaration as needed; and

8.2. Update the operating limitations associated with capability and availability per R1.2 if applicable.

M8. Each Generator Owner shall have dated evidence that demonstrates it performed an annual review and updated operating limitations as needed. Acceptable evidence may include but is not limited to the following dated documentation (electronic or hardcopy format): records that document the performance of an annual review and update to the operating limitations, as needed.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the 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 applicable 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.

- The Generator Owner shall ~~keep~~retain data or evidence to ~~show compliance for three years~~support its current Extreme Cold Weather Temperature calculation and generating unit cold weather data, plus each calculation or revision since the last audit, for Requirement R1~~, R3, and R5~~ and Measure M1~~, M3, and M5~~.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R2 or R3

is complete, whichever timeframe is greater, for ~~Requirement~~Requirements R2 and ~~Measure~~R3 and Measures M2 and M3.

- The Generator Owner shall retain the current cold weather preparedness plan(s), as evidence of review or revision history, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R4 and Measure M4. ~~The Generator Owner shall retain any Corrective Action Plans under Requirement R4 Part 4.3 for three years or until the Corrective Action Plan is complete, whichever timeframe is greater.~~
- The Generator Owner or Generator Operator shall keep data or evidence to show compliance for three years for Requirement R5 and Measure M5.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R6 is complete, whichever timeframe is greater, for Requirement R6 and Measure M6.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan is complete, whichever time frame is greater, for Requirement R7 and Measure M7.
- The Generator Owner shall maintain data or evidence to support its current Generator Cold Weather Constraint declaration, plus each revision since the last audit, for Requirement R8 and Measure M8.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner did not calculate the Extreme Cold Weather Temperature and identify generating unit(s) cold weather data in accordance with Requirement R1 for 5% or less of its applicable units.	The Generator Owner did not calculate the Extreme Cold Weather Temperature and identify generating unit(s) cold weather data in accordance with Requirement R1 for more than 5%, but less than or equal to 10% of its applicable units.	The Generator Owner did not calculate the Extreme Cold Weather Temperature and identify generating unit(s) cold weather data in accordance with Requirement R1 for more than 10%, but less than or equal to 20% of its applicable units.	The Generator Owner did not calculate the Extreme Cold Weather Temperature and identify generating unit(s) cold weather data in accordance with Requirement R1 for more 20% of its applicable units.
~~R1~~R2.	The Generator Owner did not have freeze protection measure(s) for its applicable unit(s) meeting the criteria in Requirement ~~R1~~R2 for 5% or less of its applicable units. OR The Generator Owner did not ~~explain in~~develop a ~~declaration any technical, commercial, or operational constraints that preclude the ability~~Corrective Action Plan to implement appropriate freeze protection measures for 5% or less of its applicable units.	The Generator Owner did not have freeze protection measure(s) for its applicable unit(s) meeting the criteria in Requirement ~~R1~~R2 for more than 5%, but less than or equal to 10% of its applicable units. OR The Generator Owner did not ~~explain in~~develop a ~~declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures~~Corrective Action Plan for more than 5%, but	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement ~~R1~~R2 for more than 10%, but less than or equal to 20% of its applicable units. OR The Generator Owner did not ~~explain in~~develop a ~~declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures~~Corrective Action Plan for more than 10%, but	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement ~~R1~~R2 for more than 20% of its applicable units. OR The Generator Owner did not ~~explain in~~develop a ~~declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures~~Corrective Action Plan for more than 20% of its applicable units.

		less than or equal to 10% of its applicable units.	less than or equal to 20% of its applicable units.	
~~R2~~R3.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement ~~R2~~R3 for 5% or less of its applicable units. OR The Generator Owner did not develop a ~~CAP~~Corrective Action Plan as required by Requirement ~~R2~~R3 for 5% or less of its applicable units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement ~~R2~~R3 for more than 5%, but less than or equal to 10% of its applicable units. OR The Generator Owner did not develop a ~~CAP~~Corrective Action Plan as required by Requirement ~~R2~~R3 for more than 5%, but less than or equal to 10% of its applicable units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement ~~R2~~R3 for more than 10%, but less than or equal to 20% of its applicable units. OR The Generator Owner did not develop a ~~CAP~~Corrective Action Plan as required by Requirement ~~R2~~R3 for more than 10%, but less than or equal to 20% of its applicable units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement ~~R2~~R3 for more than 20% of its applicable units. OR The Generator Owner did not develop a ~~CAP~~Corrective Action Plan as required by Requirement ~~R2~~R3 for more than 20% of its applicable units.
~~R3~~R4.	The Generator Owner implemented a cold weather preparedness plan(s~~),~~) but failed to maintain it.	The Generator Owner's cold weather preparedness plan failed to include one of the applicable Parts within Requirement ~~R3~~R4.	The Generator Owner had and maintained a cold weather preparedness plan(s~~),~~) but failed to implement it. OR The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement parts within Requirement ~~R3~~R4.	The Generator Owner does not have cold weather preparedness plan(s). OR The Generator Owner's cold weather preparedness plan failed to include three or more of the applicable requirement parts within Requirement ~~R3~~R4.
~~**R4.**~~	~~The Generator Owner completed the actions required in Requirement R4,~~	~~The Generator Owner completed the actions required in Requirement R4,~~	~~The Generator Owner failed to complete one of the applicable requirement parts in~~	~~The Generator Owner failed to complete two or more of the applicable requirement parts~~

	~~but was late by 30 calendar days or less.~~	~~but was late by greater than 30 calendar days, but less than or equal to 60 calendar days.~~	~~Requirement R4 Parts 4.1 through 4.3;~~ ~~OR~~ ~~The Generator Owner completed the actions required in Requirement R4, but was late by greater than 60 calendar days.~~	~~in Requirement R4 Parts 4.1 through 4.3.~~
R5.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of: • one applicable personnel at a single generating unit; or • 5% or less of its total applicable personnel.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of: • two applicable personnel at a single generating unit; or • more than 5%, but less than or equal to 10% of its total applicable personnel.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of: • three applicable personnel at a single generating unit; or • more than 10%, but less than or equal to 15% of its total applicable personnel.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of: • four or more applicable personnel at a single generating unit; or • more than 15% of its total applicable personnel.
R6.	The Generator Owner developed a ~~CAP~~Corrective Action Plan, but not within 150 days or by July 1 as required in Requirement R6.	The Generator Owner's ~~CAP~~Corrective Action Plan failed to comply with one of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's ~~CAP~~Corrective Action Plan failed to comply with two of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's ~~CAP~~Corrective Action Plan failed to comply with three of the elements in Requirement R6, Parts 6.1 through 6.3. OR The Generator Owner did not develop a ~~CAP~~Corrective

				Action Plan, as required by Requirement R6.
R7.	The Generator Owner implemented a ~~CAP or explained in a declaration why corrective actions are not being implemented~~Corrective Action Plan, but failed to update the ~~CAP~~Corrective Action Plan when ~~actions or timetables~~corrective action(s) changed~~,~~ in accordance with Requirement R7.	The Generator Owner implemented a Corrective Action Plan, but failed to include a timetable for implementing the selected corrective actions meeting the criteria of Requirement R7 Part 7.1.	The Generator Owner implemented a Corrective Action Plan, but failed to implement the Corrective Action Plan within the specified timetable or failed to update the Corrective Action Plan, with justification, when timetable(s) exceeded the timelines in Requirement R7 Part 7.1.	The Generator Owner failed to implement a ~~CAP~~Corrective Action Plan or ~~explain~~failed to document in a declaration why corrective actions are not being implemented in accordance with Requirement R7.
R8.	N/A	N/A	The Generator Owner failed to comply with one of the elements in Requirement R8, Parts 8.1 through 8.2.	The Generator Owner failed to comply with all of the elements in Requirement R8, Parts 8.1 through 8.2.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	~~TBD~~October 1, 2024	Drafted by Project 2021-07	New
2	TBD	Revisions drafted by Project 2021-07 due to FERC Order and inquiry Recommendations.	Revisions

Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard for a formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	10/20/2021
SAR posted for comment	12/9/2021 – 1/27/2022

Anticipated Actions	Date
45-day formal or informal comment period with ballot	9/5/2023 – 10/19/2023
45-day formal or informal comment period with additional ballot	11/4/2023 – 12/19/2023
XX-day final ballot	
Board adoption	

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

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

Term(s):
None.

A. Introduction

1. **Title:** Facility Ratings

2. **Number:** FAC-008-6~~5~~

3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.

4. **Applicability:**

   4.1. Transmission Owner

   4.2. Generator Owner

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

B. Requirements and Measures

R1. Each Generator Owner shall have documentation for determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer if the Generator Owner does not own the main step up transformer and the high side terminals of the main step up transformer if the Generator Owner owns the main step up transformer. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The documentation shall contain assumptions used to rate the generator and at least one of the following:

- Design or construction information such as design criteria, ratings provided by equipment manufacturers, equipment drawings and/or specifications, engineering analyses, method(s) consistent with industry standards (e.g. ANSI and IEEE), or an established engineering practice that has been verified by testing or engineering analysis.
- Operational information such as commissioning test results, performance testing or historical performance records, any of which may be supplemented by engineering analyses.

1.2. The documentation shall be consistent with the principle that the Facility Ratings do not exceed the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

M1. Each Generator Owner shall have documentation that shows how its Facility Ratings were determined as identified in Requirement 1.

R2. Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of interconnection with the Transmission Owner that contains all of the following. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The methodology used to establish the Ratings of the equipment that comprises the Facility(ies) shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

2.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R2, Part 2.1 including identification of how each of the following were considered:

2.2.1. Equipment Rating standard(s) used in development of this methodology.

2.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

2.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).

2.2.4. Operating limitations.[1]

2.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

2.4. The process by which the Rating of equipment that comprises a Facility is determined.

2.4.1. The scope of equipment addressed shall include, but not be limited to, conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

2.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

M2. Each Generator Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 2, Parts 2.1 through 2.4.

R3. Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The methodology used to establish the Ratings of the equipment that comprises the Facility shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

[1] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

3.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R3, Part 3.1 including identification of how each of the following were considered:

3.2.1. Equipment Rating standard(s) used in development of this methodology.

3.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

3.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).

3.2.4. Operating limitations.[2]

3.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

3.4. The process by which the Rating of equipment that comprises a Facility is determined.

3.4.1. The scope of equipment addressed shall include, but not be limited to, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

3.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

M3. Each Transmission Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 3, Parts 3.1 through 3.4.

R4. Reserved.

M4. Reserved.

R5. Reserved.

M5. Reserved.

R6. Each Transmission Owner and Generator Owner shall ~~have~~ develop Facility Ratings for its solely and jointly owned BES Facilities accurately identifying the rating of the most Limiting Element(s) in accordance ~~that are consistent~~ with ~~the~~ its associated Facility Ratings methodology or documentation for determining its Facility Ratings. *[ViolationRisk Factor: Medium] [Time Horizon: Operations Planning]*

6.1. For a BES Facility where no entity owns the Facility in its entirety, all applicable entities that own the Facility shall coordinate development of a common Facility Rating using one or a combination of the following:

- Entities shall use the most limiting Equipment Rating of their solely owned Elements and the most limiting Equipment Rating(s) from the

[2] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

other Element owner(s).

- For Element(s) with multiple owners, the owners shall designate one owner to solely develop the most limiting Equipment Rating(s) for the Element(s).

M6. Each Transmission Owner and Generator Owner shall have evidence to show that its Facility Ratings accurately identify the rating of the most Limiting Element(s) in accordance ~~are consistent~~ with the documentation for determining its Facility Ratings as specified in Requirement R1 or consistent with its Facility Ratings methodology as specified in Requirements R2 and R3 ~~(Requirement R6)~~. Where no entity owns a Facility in its entirety, each entity shall have evidence to show that its Facility Ratings were developed in accordance with Requirement R6 Part 6.1.

R7. Reserved.

M7. Reserved.

[2] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

R8. Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s): *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1. As scheduled by the requesting entities:

8.1.1. Facility Ratings

8.1.2. Identity of the most limiting equipment of the Facilities

8.2. Within 30 calendar days (or a later date if specified by the requester), for any requested Facility with a Thermal Rating that limits the use of Facilities under the requester's authority by causing any of the following: 1) An Interconnection Reliability Operating Limit, 2) A limitation of Total Transfer Capability, 3) An impediment to generator deliverability, or 4) An impediment to service to a major load center:

8.2.1. Identity of the existing next most limiting equipment of the Facility

8.2.2. The Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1.

M8. Each Transmission Owner (and Generator Owner subject to Requirement R2) shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it provided its Facility Ratings and identity of limiting equipment to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) in accordance with Requirement R8.

R9. Each Transmission Owner and Generator Owner shall have a process to correct each rating discrepancy found in either Element or Equipment Rating(s) used to develop Facility Ratings, that includes developing timelines to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

9.1. Complete the corrections

9.2. Determine if an extent of condition review is necessary

9.3. Perform extent of condition review when necessary

M9. Each Transmission Owner and Generator Owner shall have a documented process to correct rating discrepancies found in either Element or Equipment Rating(s) that includes the items identified in Requirement R9, Parts 9.1, 9.2, and 9.3

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 Reliability Standards in their respective jurisdictions.

~~**1.2. Compliance Monitoring and Enforcement Processes:**~~

- ~~Self-Certifications~~
- ~~Spot Checking~~
- ~~Compliance Audits~~
- ~~Self-Reporting~~

- ~~Compliance Violation Investigations~~
- ~~Complaints~~

~~1.3.~~1.2. **Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified belowis shorter than the time since the last audit, the ~~Compliance Enforcement Authority~~ CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

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

- The Generator Owner shall keep its current documentation (for R1) and any modifications to the documentation that were in force since last compliance audit period for Measure M1 and Measure M6.
- The Generator Owner shall keep its current, in force Facility Ratings methodology (for R2) and any modifications to the methodology that were in force since last compliance audit period for Measure M2 and Measure M6.
- The Transmission Owner shall keep its current, in force Facility Ratings methodology (for R3) and any modifications to the methodology that were in force since the last compliance audit for Measure M3 and Measure M6.
- The Transmission Owner and Generator Owner shall keep its current, in force Facility Ratings and any changes to those ratings for three calendar years for Measure M6.
- The Transmission Owner (and Generator Owner that is subject to Requirement R2) shall keep evidence for Measure M8 for three calendar years.
- The Transmission Owner and Generator Owner shall keep its current discrepancy correction process and any modifications to the process for three calendar years for Measure M9.
- If a Generator Owner or Transmission Owner 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 compliance records.

~~1.4.~~1.3. **Compliance Monitoring and Enforcement Program:** As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refersto the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.1.	The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.2.	The Generator Owner failed to provide documentation for determining its Facility Ratings.
R2.	The Generator Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology did not address all the components of Requirement R2, Part 2.4. OR The Generator Owner failed to include in its Facility Rating Methodology, three of the following Parts of Requirement R2: • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4	The Generator Owner's Facility Rating methodology failed to recognize a facility's rating based on the most limiting component rating as required in Requirement R2, Part 2.3 OR The Generator Owner failed to include in its Facility Rating Methodology four or more of the following Parts of Requirement R2: • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Transmission Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner's Facility Rating methodology did not address either of the following Parts of Requirement R3: • 3.4.1 • 3.4.2 OR The Transmission Owner failed to include in its Facility Rating methodology three of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4	The Transmission Owner's Facility Rating methodology failed to recognize a Facility's rating based on the most limiting component rating as required in Requirement R3, Part 3.3 OR The Transmission Owner failed to include in its Facility Rating methodology four or more of the following Parts of Requirement R3: • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4
R4. Reserved.				
R5. Reserved.				

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	The responsible entity failed to develop establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for 5% or less of its BES Facilities in accordance with Requirement R6, Part 6.1. solely owned and jointly owned Facilities. (R6)	The responsible entity failed to develop establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 5% of its BES Facilities or more, but less than up to (and including) 10% of its BES Facilities in accordance with Requirement R6 and Requirement R6, Part 6.1. solely owned and jointly owned Facilities. (R6)	The responsible entity failed to develop establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 10% of its BES Facilities, but less than up to (and including) 15% of its BES solely owned and jointly owned Facilities in accordance with Requirement R6 and Requirement R6, Part 6.1. (R6)	The responsible entity failed to develop establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than15% of its BES solely owned and jointly owned Facilities in accordance with Requirement R6 and Requirement R6, Part 6.1. (R6)

R7. Reserved.				
R8.	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 100%,	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 95%, but	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 90%, but	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 85% of the required Rating information to all of the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	but not less than or equal to 95% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but the information was provided up to and including 15 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to the requesting entity. (R8, Part 8.2)	not less than or equal to 90% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but did so more 15 calendar days but less than or equal to 25 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to the requesting entity. (R8, Part 8.2)	not less than or equal to 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but did so more than 25 calendar days but less than or equal to 35 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 90%, but no less than or equal to 85% of the required Rating information to the requesting entity. (R8, Part 8.2)	requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but did so more than 35 calendar days late. (R8, Part 8.2) OR The responsible entity provided less than 85 % of the required Rating information to the requesting entity. (R8, Part 8.2) OR The responsible entity failed to provide its Rating information to the requesting entity. (R8, Part 8.1)

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R9	The entity failed to include one of the elements required by Parts 9.1, 9.2, and 9.3.	The entity failed to include two of the elements required by Parts 9.1, 9.2, and 9.3.	The entity failed to include all elements required by Parts 9.1, 9.2, and 9.3.	The entity failed to have a process as required by Requirement R9.

D. Regional Variances

None.

E. Associated Documents

NERC Reliability Standard FAC-008-6 Implementation Plan

NERC Reliability Standard FAC-008-6 Technical Rationale.

~~None.~~

Version History

Version	Date	Action	Change Tracking
1	Feb 7, 2006	Approved by Board of Trustees	New
1	Mar 16, 2007	Approved by FERC	New
2	May 12, 2010	Approved by Board of Trustees	Complete Revision, merging FAC_008-1 and FAC-009-1 under Project 2009-06 and address directives from Order 693
3	May 24, 2011	Addition of Requirement R8	Project 2009-06 Expansion to address third directive from Order 693
3	May 24, 2011	Adopted by NERC Board of Trustees	
3	November 17, 2011	FERC Order issued approving FAC-008-3	
3	May 17, 2012	FERC Order issued directing the VRF for Requirement R2 be changed from "Lower" to "Medium"	
3	February 7, 2013	R4 and R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
3	November 21, 2013	R4 and R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
4	May 9, 2020	R7 and R8 and associated elements adopted by NERC Board of Trustees for retirement as part of Project 2018-03 Standards Efficiency Review Retirements.	
4	September 17, 2020	Remanded by FERC (Order No. 873).	Withdrawn
5	February 4, 2021	Adopted by NERC Board of Trustees	Requirement R8 and associated elements restored in response

Version	Date	Action	Change Tracking
			to FERC Order No. 873.
5	April 7,2021	FERC Order approving FAC-008-5. Docket No. RD21-4-000	
5	October 1,2021	Effective Date	
6	TBD	TBD	Revised under Project 2021-08

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2022-01 Reporting ACE Definition and Associated Terms | Draft 1

The drafting team (DT) is seeking comment on the following new or modified terms used in the proposed standards. The first column (*NERC Glossary Term*) provides the NERC Glossary term being modified or proposed as a new. The DT is proposing acronyms to some currently approved and new Glossary terms as shown in redline. The second column (*Currently Approved Definition*) provides the currently approved definition and the third column (*DT Proposed New or Revised)* reflects the proposed modifications to the current definitions in redline and also reflects newly proposed definitions in clean view. The fourth column identifies the currently effective Reliability Standards or *Glossary* terms in which the proposed terms are used.

Retired, Modified, or Newly Proposed Definitions					
NERC Glossary Term	**Currently Approved Definition**	**DT Proposed New or Revised REDLINE TO Currently Approved**	**Standards Effected / Definitions Affected**	**Technical Guidelines / Reference Documents**	**Notes**
ACE Diversity Interchange (ADI)		A frequency neutral exchange program where multiple participating Balancing Authorities utilize it to achieve reductions in their generation control and Reporting ACE through offsets to either Actual Net Interchange or Scheduled Net Interchange ACE components to create an ACE value closer to zero for each participant.	Included in Reporting ACE definition.		New definition

Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard for a formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/19/2022
SAR posted for comment	2/1/2022 – 3/02/2022
45-day formal or informal comment period with ballot	6/1/2023 – 7/17/2023

Anticipated Actions	Date
~~45-day formal or informal comment period with ballot~~	~~6/1/2023 – 7/17/2023~~
45-day formal or informal comment period with additional ballot	10~~9~~/6~~1~~/2023 – ~~10~~11/~~15~~20/2023
XX-day final ballot	
Board adoption	12/12/2023

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):

Distributed Energy Resource (DER)

Generators and energy storage technologies connected to the Distribution Provider's system that are capable of providing Real Power in non-isolated parallel operation with the Bulk Electric System.

- Distribution Provider refers to the NERC glossary definition, not the NERC registered entity.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-~~1~~2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owner

   4.1.3 ~~Load Serving Entity~~Distribution Provider

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   ~~This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.~~

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

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

   ~~MOD-032-2~~1, Requirement R1 ~~shall become effective on the first day of the first calendar quarter that is 12~~ 24 ~~months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-2~~1, Requirement R1 ~~shall become effective on the first day of the first calendar quarter that is 12~~ 24 ~~months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   ~~MOD-032-2~~1, Requirements R2, R3, and R4 ~~shall become effective on the first day of the first calendar quarter that is 24~~ 36 ~~months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority~~

is not required, MOD-032-21, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

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.

~~"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. "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~

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

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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

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

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

~~Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.~~

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

~~None~~

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Lower**	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) ~~Coordinator~~ did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required

						components specified in Requirement R1.
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state,

			Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission	Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short	Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short	dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data

			Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.

R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3~~4~~ within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3~~4~~ within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3~~4~~ within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3~~4~~ within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

			or Transmission Planner).	than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	
R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

NERC Reliability Standard MOD-032-2 Implementation Plan

NERC Reliability Standard MOD-032-2 Technical Rationale

~~None.~~

Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or

what it may transition into in the future, and to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

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:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

reduce the quantity of MOD standards;

add short circuit data as a requirement to the MOD standards; and

supply data and models:

add requirement identifying who provides and who receives data;

identify acceptability;

standard format;

how to deal with new technologies (user written models if no standard model exists); and

a. shareability.

b. These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.

c. The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.

d. Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

e. Rationale for R2:

f. This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."

g. **Rationale for R3:**

h. In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

i. This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and

cannot be used. The requirement also establishes a time-frame for response to address timeliness.

Rationale for R4:

This requirement will replace MOD-014 and MOD-015.

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts."* (Emphasis added).

This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection-wide cases.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0,

			MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	TBD	Revised under Project 2022-02

MOD-032-~~01~~ 2 – ATTACHMENT 1:

Data Reporting Requirements

The table~~,~~ below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [~~LSE~~DP] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Demand [~~LSE~~DP] 6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), ~~Load Serving Entity~~Distribution Provider (~~LSE~~DP), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A ~~Load Serving Entity~~Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner or as specified in the joint PC/TP modeling data requirements and reporting procedures developed per R1.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO] a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status*	8. Static Var Systems and FACTS [GO, TO, ~~LSE~~DP] 9. DC system models [TO] 10. Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS [DP, TO where DER is directly connected to the TO system and not through a DP] ~~10.~~11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]	c. Zero Sequence Data 2. Mutual Line Impedance Data~~-~~ [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	short circuit
9. Distributed Energy Resource (DER) data[4] [DP, TO where DER is directly connected to the TO system and not through a DP] [5] a. Location (bus from item 1) b. Real power capability c. Generator type (solar, battery, etc.) d. DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes. ~~9.~~10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]		

[4] The joint PC/TP modeling data requirements and reporting procedures developed per R1 will specify data flow processes and the required level of aggregation. The PC or TP may need to coordinate with the DP or TO to determine appropriate equivalent distribution system impedance.

[5] Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column.

Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard for an informal comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	June 22, 2022 – July 21, 2022

Anticipated Actions	Date
16-day informal comment period	September 13, 2023 – September 28, 2023
45-day formal or informal comment period with ballot	November 2023 – January 2024
XX-day formal or informal comment period with additional ballot	TBD
XX-day final ballot	TBD
Board adoption	TBD

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

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

Term(s):

Energy Reliability Assessment (ERA): Evaluation of the resources that supply electrical energy and ancillary services for the BPS to reliably meet the expected demand during the associated time period. ERAs account for impact of actions that occur in each iteration on all subsequent iterations, including the depletion and replenishment of finite upstream resources (e.g., fuel).

Near-Term Operational Planning Energy Reliability Assessment (OPERA): An Energy Reliability Assessment (ERA) performed for a short period of time (e.g., no more than six weeks), starting in the current operating day or next day, to be defined by the entity performing the study based on regionally specific requirements.

Study Period: The time period between the start and end of an Energy Reliability Assessment, typically assigned start and end dates, but can be more general for longer lead-time studies.

Study Frequency: The time period between when Energy Reliability Assessments are performed. This can be a prescribed number of days/weeks/months/etc. (e.g., every Monday or every month).

Study Temporal Resolution: The duration of or between each time step modeled in a study. The temporal resolution is the degree of detail with respect to time.

A. Introduction

1. **Title:** **Energy Reliability Assessments**
2. **Number:** **TOP-0XX-X**
3. **Purpose:**
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
     - **4.1.2.** Reliability Coordinator

B. Requirements and Measures

R1. Each Balancing Authority shall develop, document, and maintain a Reliability Coordinator-reviewed Near-Term Operations Planning Energy Reliability Assessments (OPERA) process. The Near-Term OPERA shall:

1.1. Have a documented Near-Term OPERA Study Frequency, Study Duration, and Study Temporal Resolution with a corresponding rationale for each selection.

1.1.1. The Near-Term OPERA study period will begin within 48 hours following the completion of each assessment.

1.1.2. The maximum Study Frequency will be set such that the time period covered by the current assessment must extend into the time period covered by the future/prompt and assessment and will be performed at least monthly.

1.1.3. The maximum Study Temporal Resolution must be 1 hour.

1.1.4. The Study Duration shall be no less than 7 days.

1.2. The Near-Term OPERA shall use a base case that includes:

1.2.1. Expected demand including demand side management and demand response;

1.2.2. Expected generator capability considering known constraints (e.g., availability and flexibility, fuel supply and inventory concerns, fuel switching capabilities, and environmental constraints ;

1.2.3. Expected transmission usage and coordinated and agreed upon transfers;

1.2.4. Expected generation and transmission outages; and

1.2.5. Expected energy storage capability

R2. Each Balancing Authority shall develop, document, and maintain a set of Reliability Coordinator-reviewed Near-Term OPERA scenarios or a method of scenario development.

2.1. The Near-Term OPERA scenarios developed shall include:

2.1.1. The scenarios listed in Table 1; and

2.1.2. Scenarios with a likely risk of occurring within the horizon which may include seasonally appropriate historical events, generation specific fuel or energy contingency scenarios, and weather events that are projected in the Near-Term OPERA horizon.

2.2. All Near-Term OPERA scenarios developed in R2.1 shall have documented criteria which specify when implementing an Operating Process is required.

R3. The Balancing Authority shall submit for review the Near-Term OPERA process and scenarios to the Reliability Coordinator annually on a mutually-agreed upon schedule. [Violation Risk Factor:] [Time Horizon: Operations Planning]

R4. Within 30 calendar days of receipt, the Reliability Coordinator shall:

4.1. Review each submitted Near-Term OPERA process and scenarios on the basis of compatibility with other Balancing Authorities' Near-Term OPERA process and scenarios;

4.2. Review each submitted Near-Term OPERA process and scenarios for coordination to avoid risks to Wide Area reliability; and

4.3. Notify each Balancing Authority of the results of its review, specifying any time frame for resubmittal of its Near-Term OPERA process and scenarios if revisions are identified.

R5. Each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R4 and resubmit its Operating Process(s) and scenarios to its Reliability Coordinator within 30 calendar days of receipt.

R6. Each Balancing Authority shall perform Near-Term OPERA according to processes documented in R1 and scenarios documented in R2.

6.1. The Balancing Authority shall notify its Reliability Coordinator within 24 hours when Near-Term OPERA results require the implementation of an Operating Process(es).

6.2. Results of the Near-Term OPERA and scenarios shall be provided to the Reliability Coordinator upon request.

R7. Each Balancing Authority shall develop and maintain one or more Reliability Coordinator-reviewed Operating Process(s) to mitigate forecasted Energy Emergencies within its Balancing Authority Area. The Operating Process(s) shall

include the following, as applicable: [Violation Risk Factor:] [Time Horizon: Operations Planning, Long-term Planning]

7.1. Roles and responsibilities for activating the Operating Process(s);

7.2. Processes to reduce the probability of forecasted Emergencies including but not limited to:

- Updated frequency of performing a Near-Term OPERA to monitor if an Energy Emergency Alert continues to be forecasted or forecasted conditions worsen;
- Notification to its Reliability Coordinator, to include the conditions for the forecasted Energy Emergency;
- Identify when to request an Energy Emergency Alert.;
- Managing generating resources in its Balancing Authority Area to address:
  - capability and availability;
  - fuel supply and inventory concerns;
  - fuel switching capabilities; and
  - environmental constraints.
- Public appeals for voluntary Load reductions;
- Requests to government agencies to implement their programs to achieve necessary energy reductions;
- Reduction of internal utility energy use;
- Use of Interruptible Load, curtailable Load and demand response;

7.2.1. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; or

7.2.2. Provisions to determine reliability impacts of:

- cold weather conditions; and
- extreme weather conditions.

R8. The Balancing Authority shall submit for review the Operating Process(s) to mitigate operating Emergencies to the Reliability Coordinator annually on a mutually agreed-upon schedule. [Violation Risk Factor:] [Time Horizon: Operations Planning]

R9. Within 30 calendar days of receipt, the Reliability Coordinator shall:

9.1. Review each submitted Operating Process(s) on the basis of compatibility with other Balancing Authorities' Operating Process(s);

9.2. Notify each Balancing Authority of the results of its review, specifying any time frame for resubmittal of its Operating Process(s) if revisions are identified.

R10. Each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R7 and resubmit its Operating Process (s) to its Reliability Coordinator within 30 calendar days of receipt.

R11. Each Balancing Authority shall implement one or more Reliability Coordinator-reviewed Operating Process(s) when a Near-Term OPERA forecasts an Energy Emergency Alert according to Table 1 or as specified for scenarios provided to the Reliability Coordinator according to R2.

R12. Each Reliability Coordinator that receives a forecasted Emergency notification from a Balancing Authority within its Reliability Coordinator Area shall notify, within 24 hours from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. [Violation Risk Factor:] [Time Horizon: Operations Planning]

Table 1. Near-Term OPERA Scenarios

Scenario	Demand Forecast	Contingency Event	If EEA 2[5] is forecasted, Operating Process(s) is Required	If EEA 3[5]is forecasted, Operating Process(s) is Required
Base Case	Normal System Forecast	None	Yes	Yes
High Demand	High Demand Forecast[4]	None	Yes	Yes
Base Case with Energy Contingency	Normal System Forecast	Loss of the largest single energy supply resource from the base case for the duration of the study period[1].	No	Yes
High Demand with Energy Contingency	High Demand Forecast[4]	Loss of the largest single energy supply resource from the base case for the duration of the study period[2].	No	Yes
Base Case with Fuel Contingency	Base Case Forecast	Fuel supply interruption that results in the loss of at least 50% of the largest subset of supply resources sharing a common fuel supply[3] (i.e., all generators on a specific segment of a pipeline or multiple stations with a common fuel source) for the duration of the study period.	No	Yes
High Demand with Fuel Contingency	High Demand Forecast[4]	Fuel supply interruption that results in the loss of at least 50% of the largest subset of supply	No	Yes

[1] This can be a generator or a transmission facility that results in the loss of supply. This is not a widespread outage of multiple resources due to a common extreme weather event.
[2] This can be a generator or a transmission facility that results in the loss of supply. This is not a widespread outage of multiple resources due to a common extreme weather event.
[3] Generators with common fuel supply are all generators on a specific segment of a pipeline or multiple stations with a common fuel source. The fuel source should include pipelines, suppliers of consumable fuels, and variable sources like solar and wind energy.
[4] High demand forecast should be coupled with the associated weather, but leaving solar and wind as modeled in the base case. Examples include 90:10 weather and load forecast or similar weather and load forecast error scenario.
[5] Energy Emergency Alert conditions are defined in EOP-011 Attachment 1.

		resources sharing a common fuel supply[3] for the duration of the study period.		

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	February 7 – March 8, 2023

Anticipated Actions	Date
45-day formal or informal comment period with ballot	July to September 2023
45-day formal or informal comment period with additional ballot	December 2023 to January 2024
45-day final ballot	February 2024
Board adoption	May 2024

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

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Term(s):

None

A. Introduction

1. **Title:** Event Reporting

2. **Number:** EOP-~~004-4~~004-5

3. **Purpose:** To improve the reliability of the Bulk Electric System **(BES)** 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~~004-5.

B. Requirements and Measures

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-~~004-4~~004-5 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 protocol(s) and each organization identified to receive an event report for event types specified in EOP-~~004-4~~004-5 Attachment 1 and in accordance with the entity responsible for reporting.

R2. Each Responsible Entity shall report events specified in EOP-~~004-4~~004-5 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day). *[Violation Risk Factor: Medium] [Time Horizon: Operations*

Assessment]

M2. Each Responsible Entity will have as evidence of reporting an event to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-~~004-4~~**004-5** Attachment 2 form or a ~~DOE-OE~~**DOE**-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 by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).

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**~~**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**~~**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.

- 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting 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 up to 24 hours after the timing requirement for submittal. 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 or by the end of the next business day, as applicable.	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 48 hours after the timing requirement for submittal. 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 or by	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 72 hours after the timing requirement for submittal. 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 or by	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 72 hours after the timing requirement for submittal. 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 or by the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the end of the next business day, as applicable.	the end of the next business day, as applicable.	end of the next business day, as applicable. OR The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1.

D. Regional Variances

None.

E. Associated Documents

~~Link~~**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.

Submit EOP-004 Attachment 2 (or ~~DOE-OE~~DOE-417 form) pursuant to Requirements R1 and R2.

~~**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.~~

~~Complete loss of Interpersonal Communication and Alternative 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 NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." The NERC Glossary of Terms defines Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."~~

~~Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control capability 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, 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 its Facility	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 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 resulting from a BES Emergency	BA	Public appeal for load reduction to maintain continuity of the BES.
System-wide voltage reduction resulting from a BES Emergency	TOP	System-wide voltage reduction of 3% or more.
Firm load ~~sheddingresultings~~**shedding resulting** from a BES Emergency	Initiating RC, BA, or TOP	Firm load shedding ≥ 100 MW (manual or automatic).

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 ≥ 1,400 MW in the ERCOT Interconnection Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources.
IBR generation loss	**BA**	**Total aggregated generation loss of ≥ 500 MW from inverter-based resource(s) (IBR)[1] occurring within a 30 second**

[1] For the purposes of EOP-004-5, an IBR is a generation resource consisting of one or more IBR unit(s) that connect to the transmission or subtransmission system via a single point of connection. An IBR unit is a primary energy source containing an individual inverter device, individual converter device, or a grouping of multiple inverters/converters. IBR units

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
		period. IBR generation loss shall be calculated using Telemetering data[2] by subtracting the lowest aggregated IBR generation output observed during a 30 second period from the pre-disturbance aggregated IBR generation output.
Loss of DC Tie Line	BA	Loss of a DC Tie Line, between two separate asynchronous systems, loaded at ≥ 500 MW.

of connection. An IBR unit is a primary energy source containing an individual inverter device, individual converter device, or a grouping of multiple inverters/converters. IBR units include solar photovoltaic, Type 3 and Type 4 wind, battery energy storage, high voltage direct current (HVDC) transmission, and dynamic reactive devices such as static synchronous compensators (STATCOMs) and static VAR compensators (SVCs).

[2] Indicated IBR generation loss due to a failure of SCADA or Telemetering data is not reportable under this requirement.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing).
Unplanned evacuation of its BES control center	RC, BA, TOP	Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.
Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center	RC, BA, TOP	Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at its staffed BES control center	RC, BA, TOP	Complete loss of monitoring or control capability at its staffed 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~~a DOE-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, Option 1. Also submit to other applicable 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:**	
	(Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical threat to its Facility ☐ Physical threat to its BES control center ☐ BES Emergency: ☐ firm load shedding ☐ public appeal for load reduction ☐ System-wide voltage reduction ☐ voltage deviation on a Facility ☐ uncontrolled loss of firm load ☐ System separation (islanding) ☐ Generation loss ☐ **IBR generation loss** ☐ **Loss of DC Tie Line** ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss ☐ Unplanned evacuation of its BES control center ☐ Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center ☐ Complete loss of monitoring or control capability at its staffed BES control center	Written description (optional):

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.	
4	February 9, 2017	Adopted by the NERC Board of Trustees	Revised
4	January 18, 2018	FERC order issued approving EOP-004-4. Docket No. RM17-12-000	
5	**TBD**	**Adopted by the NERC Board of Trustees**	

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

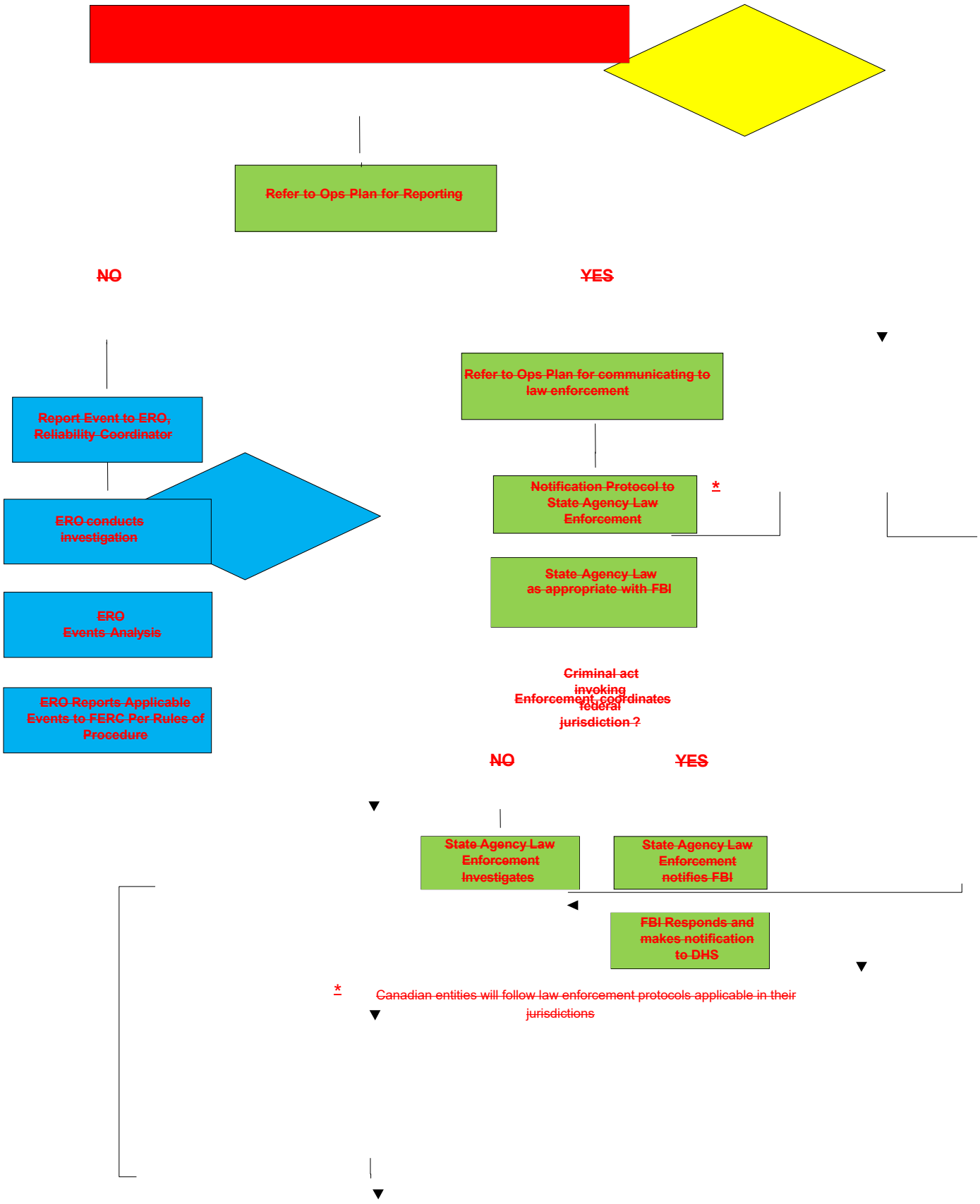
The reliability objective of EOP-004-4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be 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

Supplemental Material

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 information 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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

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

Requested information			
SAR Title:	Internal Network Security Monitoring (INSM) (as revised by the Standard Drafting Team)		
Date Submitted:	March 7, 2023 (August 23, 2023)		
SAR Requester			
Name:	Michaelson Buchanan, Dan Goodlett, Larry Collier (Revised by Project 2023-03 Standard Drafting Team)		
Organization:	NERC		
Telephone:	470.725.5268, 470.522.7367, 470.716.2923	Email:	Michaelson.buchanan@nerc.net Dan.goodlett@nerc.net Larry.Collier@nerc.net
SAR Type (Check as many as apply)			
☒ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
While the CIP Reliability Standards require monitoring of the Electronic Security Perimeter and associated systems for high and medium impact BES Cyber Systems, the CIP-networked environment remains vulnerable to attacks that bypass network perimeter-based security controls traditionally used to identify the early phases of an attack. This ~~presents~~ represents a gap in the currently effective CIP Reliability Standards. To address this gap, CIP Reliability Standards should be created or modified to require INSM for all high impact BES Cyber Systems and medium impact BES Cyber Systems with External Routable Connectivity (ERC) to ensure the detection of anomalous network activity indicative of an attack in progress. These provisions will increase the probability of early detection and allow for quicker mitigation and recovery from an attack. Current CIP Reliability Standards are insufficient to			

Requested information
protect against insider threats or vulnerabilities that are exploited through supply chain attacks such as SolarWinds.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
As directed by FERC Order No. 887, modify or create new Standard(s) that require INSM within a trusted Critical Infrastructure Protection networked environment for all high impact BES Cyber Systems with and without ERC and medium impact BES Cyber Systems with ERC.
Project Scope (Define the parameters of the proposed project):
The Standards Drafting Team (SDT) will create or modify the Reliability Standards and associated definitions as necessary to comply with the FERC order[1]. The scope of the project will include: • All high impact BES Cyber Systems~~,~~ ; and • All medium impact BES Cyber Systems with ERC. The scope of the project should not extend to: • medium Impact BES Cyber Systems without ERC; or • low impact BES cyber systems. ~~The ERO is in the process of completing a feasibility study, pursuant to the Order, which will examine the risks, challenges and potential solutions for those BES Cyber systems not in scope.~~
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[2] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Create new or modified existing CIP Reliability Standards that are forward-looking, objective-based, and that address the following three security objectives that pertain to INSM. First, any new or modified CIP Reliability Standards should address the need for responsible entities to develop baselines of their network traffic inside their CIP-networked environment. Second, any new or modified CIP Reliability Standards should address the need for responsible entities to monitor for and detect unauthorized activity, connections, devices, network communications, and software inside the CIP-networked environment. And third, any new or modified CIP Reliability Standards should provide flexibility to ~~require~~ responsible entities ~~to~~ in how they identify anomalous activity to a high level of confidence by: (1) logging network traffic (note that packet capture is one means of accomplishing this goal); (2) maintaining logs, and other data collected, regarding network traffic; and (3) implementing measures to minimize the likelihood of an attacker removing evidence of their tactics, techniques, and procedures from compromised devices.

[1] The SDT is aware that the ERO is in the process of completing a feasibility study, pursuant to the Order, which will examine the risks, challenges and potential solutions for those BES Cyber Systems not in scope.

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

Requested information
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Beyond the time and resources needed to serve on the Standard Drafting Team, the cost to entities will vary based on their current system architecture. While many entities may have the controls in place, others may not which could require a significant cost investment depending on their footprint.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Applicability will be the same as current CIP standards - Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, ~~Interchange Coordinator, Interchange Authority,~~ Reliability Coordinator, Transmission Operator, Transmission Owner
Do you know of any consensus building activities[3] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The SAR has been developed in response to FERC Order No. 887. The final Order was consistent with feedback provided by NERC and industry through the NOPR process. NERC and the ERO Enterprise have convened a response team to address directives in the FERC Order which included a review of this SAR.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
The following projects and Reliability standards should be assessed for impact: • Projects 2016-02~~, 2019-03~~ and 2022-05 • Reliability Standards CIP-005~~-7~~, CIP-007, CIP-008, CIP-010~~-4~~, and CIP-013~~-2~~
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
This Standards Authorization Request has been developed pursuant to FERC Order No. 887.

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

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

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

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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
N/A	

For Use by NERC Only

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

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Link to Ballot Results:
https://cmapbooks.nerc.net/Ballots.aspx
(clicking in the column to the right of "Ballot Results" causes Ballot to the Ballot Results)

Line	Project	Ballot Results	Ballot Type	Start Date	End Date (Actual Ballot Close Date Shown)	Ballot Results	Recommendation / Date	Have NITs Voted	Comments
1	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Kemper, m	Initial Ballot	4/25/2008	5/5/2008	Quorum: 82.61% Approval: 100.00%			
2	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - NSGC,q	Initial Ballot	4/25/2008	5/5/2008	Quorum: 82.61% Approval: 75.00%			
3	Project 2008-04	FAC-014, FAC-011, FAC-014, Order 705, m	Initial Ballot	5/2/2008	5/21/2008	Quorum: 89.47% Approval: 85.00%			
4	Project 2008-07	Interpretation Request - EOP-002 - Broomfield, m	Initial Ballot	5/5/2008	5/21/2008	Quorum: 89.47% Approval: 100.00%			
5	Project 2008-04	FAC-014, FAC-011, FAC-014, Order 705, m	Reinitiation Ballot	5/15/2008	5/22/2008	Quorum: 95.56% Approval: 95.12%			
6	Project 2008-09	Request for Interpretation - EOP-002-2, IRCOT, q	Initial Ballot	5/20/2008	7/1/2008	Quorum: 82.76% Approval: 85.71%			
7	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Kemper, m	Reinitiation Ballot	6/27/2008	7/7/2008	Quorum: 93.67% Approval: 79.66%			
8	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - NSGC,q	Reinitiation Ballot	6/27/2008	7/7/2008	Quorum: 93.67% Approval: 78.31%			
9	Pre-2006	BOG Standard - BO-010, m	Initial Ballot	7/31/2008	7/30/2008	Quorum: 92.71% Approval: 96.55%			
10	Pre-2006	BOG Standard - BO-009, m	Initial Ballot	7/31/2008	7/30/2008	Quorum: 92.8% Approval: 89.83%			
11	Pre-2006	BOG Standard - BO-008, m	Initial Ballot	7/31/2008	7/30/2008	Quorum: 92.47% Approval: 96.55%			
12	Project 2008-07	GO, et al Standard - MOD-028, m	Initial Ballot	7/31/2008	7/30/2008	Quorum: 92.27% Approval: 96.36%			
13	Project 2006-07	GO, et al Standard - MOD-029, m	Initial Ballot	7/31/2008	7/30/2008	Quorum: 92.27% Approval: 93.62%			
14	Project 2006-07	GO, et al Standard - MOD-028, m	Initial Ballot	7/31/2008	7/30/2008	Quorum: 94.64% Approval: 96.36%			
15	Project 2006-07	GO, et al Standard - MOD-030, m	Initial Ballot	7/31/2008	7/30/2008	Quorum: 94.27% Approval: 88.64%			
16	Project 2006-07	GO, et al Standard - MOD-031, m	Initial Ballot	7/31/2008	7/30/2008	Quorum: 94.27% Approval: 75.61%			
17	Project 2008-10	Request for Interpretation - CIP-006-1, Progress Energy, m	Initial Ballot	8/7/2008	8/22/2008	Quorum: 89.18% Approval: 93.55%			
18	Pre-2006	BOG Standard - BO-006, m	Reinitiation Ballot	8/12/2008	8/21/2008	Quorum: 93.75% Approval: 89.49%			
19	Pre-2006	BOG Standard - BO-005, m	Reinitiation Ballot	8/12/2008	8/21/2008	Quorum: 93.68% Approval: 93.55%			
20	Pre-2006	BOG Standard - BO-010, m	Reinitiation Ballot	8/12/2008	8/21/2008	Quorum: 93.75% Approval: 89.49%			
21	Project 2006-07	GO, et al Standard - MOD-025, m	Reinitiation Ballot	8/12/2008	8/21/2008	Quorum: 94.87% Approval: 96.36%			
22	Project 2006-07	GO, et al Standard - MOD-026, m	Reinitiation Ballot	8/12/2008	8/21/2008	Quorum: 95.21% Approval: 91.49%			
23	Project 2006-07	GO, et al Standard - MOD-028, m	Reinitiation Ballot	8/12/2008	8/21/2008	Quorum: 95.21% Approval: 96.36%			
24	Project 2006-07	GO, et al Standard - MOD-029, m	Reinitiation Ballot	8/12/2008	8/21/2008	Quorum: 95.04% Approval: 93.62%			
25	Project 2006-07	GO, et al Standard - MOD-030, m	Reinitiation Ballot	8/12/2008	8/21/2008	Quorum: 95.21% Approval: 91.26%			
26	Project 2008-11	Request for Interpretation - VAR-002-1, ISO Consulting, q	Initial Ballot	9/8/2008	9/17/2008	Quorum: 89.87% Approval: 85.87%			
27	Project 2006-07	GO, et al Standard - MOD-004, m	Initial Ballot	9/11/2008	9/21/2008	Quorum: 79.24% Approval: 96.36%			
28	Project 2007-14	Permanent Changes to CI Timing Table, m	Initial Ballot	9/11/2008	9/21/2008	Quorum: 79.24% Approval: 100.00%			
29	Project 2008-07	Request for Interpretation - Bloomfield Power - EOP-002, m	Pre-ballot	10/8/2008	10/24/2008	Quorum: 89.47% Approval: 94.12%			
30	Project 2008-13	Request for Interpretation - TOP-002-2, Orlando Utilities Commission, m	Initial Ballot	10/21/2008	10/30/2008	Quorum: 83.03% Approval: 96.36%			
31	Project 2006-01	Project 2006-01 - FAC-003-1, q	Initial Ballot	10/27/2008	11/6/2008	Quorum: 89.47% Approval: 82.27%			
32	Project 2006-09	Project 2006-09 - FAC-008-2 - Ashby Ratings, m	Initial Ballot	10/27/2008	11/6/2008	Quorum: 89.11% Approval: 70.83%			
33	Project 2006-07	GO, et al Standard - MOD-006, m	Reinitiation Ballot	10/28/2008	11/6/2008	Quorum: 89.11% Approval: 83.71%			
34	Project 2006-07	Project 2006-07 (GO,GOP)-MOD-030-2, m	Initial Ballot	11/5/2008	11/20/2008	Quorum: 81.77% Approval: 96.36%			
35	Project 2006-09	Project 2006-09 - FAC-008-2 - Ashby Ratings, m	Reinitiation Ballot	11/10/2008	11/19/2008	Quorum: 93.06% Approval: 57.14%			
36	Project 2008-13	Request for Interpretation - TOP-002-2, Orlando Utilities Commission, m	Reinitiation Ballot	11/10/2008	11/19/2008	Quorum: 93.06% Approval: 87.87%			
37	Project 2006-01	Project 2006-01 - FAC-003-1, q	Reinitiation Ballot	11/21/2008	12/1/2008	Quorum: 91.66% Approval: 83.33%			
38	Project 2008-13	Request for Interpretation - CIP-006-1a - US Army COE, m	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.21% Approval: 97.29%			
39	Project 2008-14	CIP-002-2 (4) Revisions, m	Initial Ballot	1/8/2009	1/16/2009	Quorum: 91.21% Approval: 93.33%			
40	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting, q	Reinitiation Ballot	1/8/2009	1/21/2009	Quorum: 91.67% Approval: 83.21%			
41	Project 2006-07	Project 2006-07 (GO,GOP)-MOD-030-2, m	Initial Ballot	1/20/2009	1/29/2009	Quorum: 91.67% Approval: 85.39%			
42	Project 2008-14	CIP-002-2 (4) Revisions, m	Reinitiation Ballot	1/28/2009	2/6/2009	Quorum: 92.05% Approval: 94.66%			
43	Project 2008-13	Request for Interpretation - CIP-006-1a - US Army COE, m	Reinitiation Ballot	2/8/2009	2/16/2009	Quorum: 90.81% Approval: 89.12%			
44	Project 2008-09	Interpretation Request - EOP-001 - AS, IRCOR, m	Initial Ballot	2/27/2009	3/9/2009	Quorum: 89.47% Approval: 96.36%			
45	Project 2008-14	Project 2008-14 Interpretation Manitoba Hydro, m	Initial Ballot	3/16/2009	3/26/2009	Quorum: 89.76% Approval: 92.62%			
46	Project 2008-06	Project 2008-06 CIP-002-2 CIP-003-2 Revisions, m	Initial Ballot	4/1/2009	4/10/2009	Quorum: 89.47% Approval: 84.69%			
47	Project 2009-10	Project 2009-10 Interpretation - CIP(FAC - PRC-005-1 R1.1, m	Initial Ballot	4/8/2009	4/17/2009	Quorum: 92.76% Approval: 96.36%			
48	Project 2009-03	Project 2009-03 EOP-001, EOP-002, EOP-004 System Restoration and Blackstart, m	Initial Ballot	4/14/2009	4/23/2009	Quorum: 89.81% Approval: 76.63%			
49	Project 2008-06	Project 2008-06 CIP-002-2 CIP-003-2 Revisions, m	Reinitiation Ballot	5/7/2009	5/17/2009	Quorum: 91.89% Approval: 88.87%			
50	Project 2008-14	Project 2008-14 Interpretation Manitoba Hydro, m	Reinitiation Ballot	5/7/2009	5/17/2009	Quorum: 92.02% Approval: 94.66%			
51	Project 2009-11	Project 2009-11 Interpretation MISO Reliability Coordinator Subcommittee RC-11-1, m	Initial Ballot	5/22/2009	5/31/2009	Quorum: 89.81% Approval: 88.77%			
52	Project 2009-03	Project 2009-03 EOP-001, EOP-002, EOP-004 System Restoration and Blackstart, m	Reinitiation Ballot	5/26/2009	5/29/2009	Quorum: 91.08% Approval: 84.69%			
53	Project 2009-15	Project 2009-15 Interpretation - NYSG - IRO-001-1, NYSG-DSS-1, m	Initial Ballot	5/26/2009	6/4/2009	Quorum: 92.83% Approval: 93.14%			
54	Project 2009-11	Project 2009-11 Interpretation MISO Reliability Coordinator Subcommittee RC-11-1, m	Reinitiation Ballot	5/26/2009	6/5/2009	Quorum: 94.05% Approval: 88.77%			
55	Project 2009-14	Project 2009-14 Interpretation - FacilCorp - TPL-002-0a, m	Initial Ballot	6/1/2009	6/11/2009	Quorum: 87.23% Approval: 95.71%			
56	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716, m	Initial Ballot	6/12/2009	6/21/2009	Quorum: 89.47% Approval: 95.83%			
57	Project 2008-14	Project 2008-14 Qlty Sol CIP-002-2 through CIP-009-2, m	Initial Ballot	6/15/2009	6/24/2009	Quorum: 87.23% Approval: 94.12%			
58	Project 2008-14	Project 2008-14 Qlty Sol CIP-002-2 through CIP-009-2, m	Reinitiation Ballot	7/7/2009	7/16/2009	Quorum: 93.77% Approval: 94.96%			
59	Project 2009-15	Project 2009-15 Interpretation - NYSG - IRO-001-1, NYSG-DSS-1, m	Reinitiation Ballot	7/8/2009	7/17/2009	Quorum: 93.65% Approval: 93.14%			
60	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716, m	Reinitiation Ballot	7/22/2009	7/31/2009	Quorum: 87.23% Approval: 95.83%			
61	Project 2009-10	Project 2009-10 Interpretation - CIP(FAC - PRC-005-1 R1.1, m	Reinitiation Ballot	7/24/2009	8/3/2009	Quorum: 91.26% Approval: 95.65%			
62	Project 2009-14	Project 2009-14 Interpretation - FacilCorp - TPL-002-0a, m	Reinitiation Ballot	7/24/2009	8/3/2009	Quorum: 91.26% Approval: 95.71%			
63	Project 2007-23	Project 2007-23 TPL Violation Severity Levels, m	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 96.36%			
64	Project 2007-23	Project 2007-23 FAP Violation Severity Levels, m	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 88.14%			
65	Project 2007-23	Project 2007-23 PRC Violation Severity Levels, m	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.32% Approval: 96.36%			
66	Project 2007-23	Project 2007-23 IRO Violation Severity Levels, m	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.32% Approval: 96.61%			
67	Project 2007-23	Project 2007-23 MOT, PER, and RAC Violation Severity Levels, m	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 96.36%			
68	Project 2007-23	Project 2007-23 CIP, and EOC Violation Severity Levels, m	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.69% Approval: 87.93%			
69	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels, m	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.69% Approval: 85.79%			
70	Project 2007-23	Project 2007-23 EOL Violation Severity Levels, m	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.69% Approval: 96.36%			
71	Project 2008-08	Project 2008-08 EOP Violation Severity Levels, m	Initial Ballot	7/31/2009	8/10/2009	Quorum: 87.06% Approval: 87.41%			
72	Project 2009-17	Project 2009-17 Interpretation - CIP Device and Ex Spec - PSC-2001-2 and PSC-2011-1, m	Initial Ballot	7/31/2009	8/10/2009	Quorum: 87.06% Approval: 93.22%			
73	RSAW V7	Reliability Standards Development Proceduru - Version 7 - June 2009, m	Re-ballot	7/27/2009	8/14/2009	Quorum: 90.91% Approval: 74.74%			
74	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-002-2, q	Initial Ballot	8/6/2009	8/17/2009	Quorum: 89.47% Approval: 68.91%			
75	Project 2007-23	Project 2007-23 TPL Violation Severity Levels, m	Reinitiation Ballot	8/17/2009	8/27/2009	Quorum: 91.36% Approval: 96.36%			
76	Project 2007-23	Project 2007-23 EOL Violation Severity Levels, m	Reinitiation Ballot	8/17/2009	8/27/2009	Quorum: 91.36% Approval: 95.61%			
77	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels, m	Reinitiation Ballot	8/17/2009	8/27/2009	Quorum: 91.41% Approval: 85.79%			
78	Project 2007-23	Project 2007-23 PRC and EOC Violation Severity Levels, m	Reinitiation Ballot	8/17/2009	8/27/2009	Quorum: 91.67% Approval: 88.04%			
79	Project 2007-23	Project 2007-23 MOT, PER, and RAC Violation Severity Levels, m	Reinitiation Ballot	8/17/2009	8/27/2009	Quorum: 91.36% Approval: 88.73%			
80	Project 2007-23	Project 2007-23 IRO Violation Severity Levels, m	Reinitiation Ballot	8/17/2009	8/27/2009	Quorum: 91.36% Approval: 96.61%			
81	Project 2007-23	Project 2007-23 FAP Violation Severity Levels, m	Reinitiation Ballot	8/17/2009	8/27/2009	Quorum: 91.41% Approval: 88.14%			
82	Project 2007-23	Project 2007-23 CIP Violation Severity Levels, m	Reinitiation Ballot	8/17/2009	8/27/2009	Quorum: 91.41% Approval: 87.93%			
83	Project 2008-08	Project 2008-08 EOP Violation Severity Levels, m	Reinitiation Ballot	8/17/2009	8/27/2009	Quorum: 91.36% Approval: 87.41%			
84	Order 706-B	Order 706-B Nuclear Implementation Plan, m	Initial Ballot	8/18/2009	8/28/2009	Quorum: 87.96% Approval: 87.37%			
85	Project 2008-07	Request for Interpretation - Bloomfield Power - EOP-002, m	Reinitiation Ballot	8/20/2009	8/31/2009	Quorum: 89.81% Approval: 91.67%			
86	Project 2009-12	Project 2009-12 - Interpretation - FacilCorp - CIP-002-2, q	Initial Ballot	8/27/2009	9/6/2009	Quorum: 89.81% Approval: 79.81%			
87	Project 2009-13	Project 2009-13 - Interpretation - FacilCorp - CIP-002-2, q	Initial Ballot	8/27/2009	9/6/2009	Quorum: 89.81% Approval: 79.81%			
88	Project 2009-14	Project 2009-14 - Interpretation - Entergy (EI Wetzel), q	Initial Ballot	8/27/2009	9/6/2009	Quorum: 89.81% Approval: 84.62%			
89	Order 706-B	Order 706-B Nuclear Implementation Plan, m	Reinitiation Ballot	9/1/2009	9/10/2009	Quorum: 87.61% Approval: 87.37%			
90	RSAW V7	Reliability Standards Development Proceduru - Version 7 - June 2009, m	Reinitiation Ballot	9/3/2009	9/14/2009	Quorum: 90.91% Approval: 76.09%			
91	Project 2008-06	Project 2008-06 Cyber Security FERC and IESs for Version 4 CIP Standards1, q	Initial Ballot	9/22/2009	9/21/2009	Quorum: 87.61% Approval: 91.67%			
92	Project 2009-18	Project 2009-18 - Interpretation - NIOC - CIP-002-2, m	Initial Ballot	9/8/2009	9/21/2009	Quorum: 89.21% Approval: 100.00%			
93	Project 2008-04	Project 2008-04 - Back-up facilities - EOP-008-1, m	Initial Ballot	9/16/2009	9/28/2009	Quorum: 83.28% Approval: 100.00%			
94	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-002-2, q	Initial Ballot	9/25/2009	10/5/2009	Quorum: 89.81% Approval: 68.31%			
95	Project 2008-10	Project 2008-10 - Interpretation of CIP-002-1 Request for Fort Pidgeon Energy	Initial Ballot	9/30/2009	10/13/2009	Quorum: 89.81% Approval: 75.47%			
96	Project 2009-12	Project 2009-12 - Interpretation - FacilCorp - CIP-002-1, q	Reinitiation Ballot	10/14/2009	10/26/2009	Quorum: 94.29% Approval: 79.81%			
97	Project 2008-06	Project 2008-06 Cyber Security FERC and IESs for Version 4 CIP Standards1, q	Reinitiation Ballot	11/2/2009	11/11/2009	Quorum: 93.75% Approval: 94.24%			
98	Project 2008-09	Project 2008-09 - Interpretation - IRO1 - Revision 2, m	Initial Ballot	11/5/2009	11/16/2009	Quorum: 89.47% Approval: 89.47%			
99	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response, m	Initial Ballot	11/20/2009	11/30/2009	Quorum: 89.81% Approval: 89.81%			
100	Project 2009-17	Project 2009-17 - Interpretation - FAR Device and Ex Spec Request, m	Initial Ballot	11/24/2009	12/7/2009	Quorum: 89.81% Approval: 93.65%			
101	Project 2009-19	Project 2009-19 - Interpretation - BAL-005-0.2 - Energy Mark, Inc., m	Initial Ballot	11/30/2009	12/7/2009	Quorum: 87.21% Approval: 96.36%			
102	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response, m	Reinitiation Ballot	12/3/2009	12/14/2009	Quorum: 93.03% Approval: 89.81%			
103	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers, m	Initial Ballot	12/3/2009	12/14/2009	Quorum: 94.11% Approval: 96.36%			
104	Project 2009-13	Project 2009-13 - Interpretation - FacilCorp - CIP-002-1, q	Reinitiation Ballot	12/11/2009	12/21/2009	Quorum: 93.65% Approval: 78.77%			
105	Project 2009-24	Project 2009-24 - Interpretation - FERC - EOP-005-1, m	Initial Ballot	1/5/2010	1/15/2010	Quorum: 89.81% Approval: 77.78%			
106	Project 2009-25	Project 2009-25 - Interpretation - BPA - BAL-001-0.1a and BAL-002-0, m	Initial Ballot	1/5/2010	1/15/2010	Quorum: 89.89% Approval: 96.36%			
107	Project 2009-26	Project 2009-26 - Interpretation - MISO - CIP-004-2, m	Initial Ballot	1/8/2010	1/19/2010	Quorum: 89.21% Approval: 97.14%			
108	Project 2009-06	Project 2009-06 - Facility Ratings TPL-002-2	Initial Ballot	1/12/2010	1/22/2010	Quorum: 89.81% Approval: 75.36%			
109	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for PMPA1, m	Initial Ballot	1/15/2010	1/25/2010	Quorum: 89.89% Approval: 96.36%			
110	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for PMPA, m	Initial Ballot	2/10/2010	2/22/2010	Quorum: 87.96% Approval: 91.78%			
111	Project 2009-29	Project 2009-29 - Interpretation - TOP-001-2a for PMPA, m	Initial Ballot	2/11/2010	2/22/2010	Quorum: 89.89% Approval: 94.12%			
112	Project 2009-19	Project 2009-19 - Interpretation - BAL-005-0.2 Northeast Power Pool RSC, m	Initial Ballot	2/23/2010	2/26/2010	Quorum: 89.89% Approval: 98.89%			
113	Project 2009-30	Project 2009-30 - Interpretation - BAL-003-0 - Energy Mark, Inc., m	Reinitiation Ballot	2/16/2010	2/26/2010	Quorum: 92.46% Approval: 96.36%			
114	Project 2009-30	Project 2009-30 - Interpretation - FAC-003-1a for BCTC, q	Initial Ballot	2/12/2010	2/26/2010	Quorum: 89.21% Approval: 96.36%			
115	Project 2008-02	Project 2008-02 - Assets Transmission Across Nodes - TPL-002-1, m	Initial Ballot	2/16/2010	3/1/2010	Quorum: 89.89% Approval: 81.82%			
116	Project 2009-31	Project 2009-31 - Interpretation - TOP-001-1 for PMPP, m	Initial Ballot	3/5/2010	3/16/2010	Quorum: 89.24% Approval: 96.36%			
117	Project 2009-06	Project 2009-06 - Facility Ratings TPL-004-2	Reinitiation Ballot	3/8/2010	3/18/2010	Quorum: 93.71% Approval: 78.21%			
118	Project 2009-32	Project 2009-32 - Interpretation - EOP-001-1a for PMPP, m	Initial Ballot	3/15/2010	3/31/2010	Quorum: 89.89% Approval: 77.06%			
119	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers (Revision 1), m	Initial Ballot	3/29/2010	4/8/2010	Quorum: 89.21% Approval: 96.36%			
120	Project 2008-09	Project 2008-09 - Interpretation - IRO1R - Revision 2, m	Initial Ballot	4/15/2010	4/26/2010	Quorum: 91.67% Approval: 98.64%			
121	IPM	Standards Process Manual Revisions, m	Initial Ballot	4/15/2010	4/26/2010	Quorum: 87.96% Approval: 89.12%			
122	Project 2009-17	Project 2009-17 - Interpretation - FAR Device and Ex Spec Request, m	Initial Ballot	4/28/2010	5/6/2010	Quorum: 93.65% Approval: 94.12%			
123	IPM	Standards Process Manual Revisions, m	Reinitiation Ballot	4/28/2010	5/10/2010	Quorum: 93.65% Approval: 90.09%			
124	Project 2010-11	Project 2010-11 TOP-002-2a TPL Table 1 Order, m	Initial Ballot	5/11/2010	5/21/2010	Quorum: 94.41% Approval: 96.36%			
125	Project 2010-09	Project 2010-09 PER Implementation Plans for CIP Version 2 and Version 3, m	Initial Ballot	5/19/2010	6/1/2010	Quorum: 89.81% Approval: 89.81%			
126	Project 2010-09	Project 2010-09 PER Implementation Plans for CIP Version 2 and Version 3, m	Reinitiation Ballot	6/22/2010	7/2/2010	Quorum: 89.19% Approval: 89.19%			
127	Project 2009-04	Project 2009-04 - Backup Facilities - Revision 1, m	Initial Ballot	6/25/2010	7/6/2010	Quorum: 89.81% Approval: 75.41%			
128	Project 2009-08	Project 2009-08 - Reliability Coordination - Transmission Loading Relief - m	Initial Ballot	6/25/2010	7/6/2010	Quorum: 89.81% Approval: 84.69%			
129	Project 2007-01	Project 2007-01 Undefined Requires Load Shedding PRC-006-1 and EOP-003-1	Initial Ballot	7/7/2010	7/17/2010	Quorum: 94.94% Approval: 96.36%			
130	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing PRC-005-2	Initial Ballot	7/8/2010	7/17/2010	Quorum: 89.81% Approval: 72.51%			
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: 89.81% Approval: 80.00%			
132	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing Protection System Definition	Initial Ballot	7/8/2010	7/17/2010	Quorum: 87.81% Approval: 89.81%			
133	Project 2007-07	Project 2007-07 Vegetation Management FAC-003-1	Initial Ballot	7/9/2010	7/19/2010	Quorum: 89.81% Approval: 83.69%			
134	Project 2008-04	Project 2008-04 - Backup Facilities - Revision 1, m	Reinitiation Ballot	7/16/2010	7/26/2010	Quorum: 93.81% Approval: 84.62%			
135	Project 2007-17	Project 2007-17 Protection System Maintenance Protection System definition	Successive Ballot	7/22/2010	8/2/2010	Quorum: 94.79% Approval: 94.81%			
136	Project 2007-01	Project 2007-01 Undefined Requires Load Shedding PRC-006-1 and EOP-003-1	Successive Ballot	7/26/2010	8/5/2010	Quorum: 94.94% Approval: 96.36%			
137	Project 2008-08	Project 2008-08 - Reliability Coordination - Transmission Loading Relief - m	Reinitiation Ballot	8/5/2010	8/16/2010	Quorum: 94.12% Approval: 93.94%			
138	Project 2007-04	Project 2007-04 - Certifying System Operators - PER-005-1	Initial Ballot	8/16/2010	8/26/2010	Quorum: 89.81% Approval: 79.17%			
139	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-003-3	Initial Ballot	8/17/2010	8/27/2010	Quorum: 96.46% Approval: 96.36%			
140	Project 2007-01	Project 2007-01 Undefined Requires Load Shedding PRC-006-1 and EOP-003-1	Successive Ballot	8/24/2010	9/4/2010	Quorum: 95.71% Approval: 95.71%			
141	Project 2007-17	Project 2007-17 Protection System Maintenance Protection System definition	Successive Ballot	9/2/2010	10/14/2010	Quorum: 94.81% Approval: 94.81%			
142	Project 2008-09	Project 2008-09 - Interpretation - IRO1R - Revision 2, m	Reinitiation Ballot	9/8/2010	10/14/2010	Quorum: 89.11% Approval: 98.64%			
143	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for PMPP, m	Reinitiation Ballot	10/5/2010	10/15/2010	Quorum: 91.58% Approval: 91.78%			
144	Project 2009-27	Project 2009-27 - Interpretation - TOP-001-2a for PMPP, m	Reinitiation Ballot	10/8/2010	10/18/2010	Quorum: 91.21% Approval: 94.12%			
145	Project 2007-01	Project 2007-01 Undefined Requires Load Shedding PRC-006-1 and EOP-003-1	Successive Ballot	10/18/2010	10/28/2010	Quorum: 95.69% Approval: 95.87%			
146	Project 2008-06	Project 2008-06 Cyber Security TSA Directs 4 CIP Standards1, m	Initial Ballot	10/25/2010	11/5/2010	Quorum: 93.65% Approval: 94.24%			
147	Project 2010-16	Project 2010-16 CIP-010-1 Planning Transfer Capability, m	Initial Ballot	10/25/2010	11/5/2010	Quorum: 88.54% Approval: 95.65%			
148	2010 IPM	2010 Standard Processes Manual (Proposed Changes), m	Initial Ballot	10/28/2010	11/7/2010	Quorum: 87.96% Approval: 93.71%			
149	Project 2007-17	Project 2007-17 Protection System Maintenance Protection System definition	Reinitiation Ballot	11/1/2010	11/11/2010	Quorum: 89.81% Approval: 96.36%			
150	2010 IPM	2010 Standard Processes Manual (Proposed Changes), m	Reinitiation Ballot	11/9/2010	11/23/2010	Quorum: 87.96% Approval: 92.88%			
151	Project 2009-17	Project 2009-17 - Interpretation - FAR Device and Ex Spec Request, m	Reinitiation Ballot	11/15/2010	11/25/2010	Quorum: 89.81% Approval: 95.61%			
152	Project 2008-06	Project 2008-06 Cyber Security TSA Directs 4 CIP Standards1, clo, m	Initial Ballot	11/5/2010	11/15/2010	Quorum: 87.27% Approval: 94.24%			
153	Project 2010-15	Project 2010-15 - Essential Action Revisions to CIP-003-3	Initial Ballot	11/5/2010	11/11/2010	Quorum: 92.46% Approval: 97.09%			
154	Project 2007-04	Project 2007-04 - Certifying System Operators- PER-005-1	Initial Ballot	11/5/2010	11/15/2010	Quorum: 89.81% Approval: 86.11%			
155	Project 2010-13	Project 2010-13 - Rebo Loadability Order - PRC-023	Initial Ballot	11/7/2010	11/16/2010	Quorum: 89.89% Approval: 91.11%			
156	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing PRC-005-2	Successive Ballot	11/16/2010	11/26/2010	Quorum: 94.81% Approval: 96.81%			
157	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing PRC-005-2	Non-binding Poll	11/16/2010	11/26/2010	Quorum: 94.86% Approval: 93.08%			
158	Project 2008-06	Project 2008-06 Cyber Security TSA Directs 4 CIP Standards1, clo, m	Reinitiation Ballot	11/26/2010	12/6/2010	Quorum: 93.65% Approval: 95.52%			
159	Project 2010-11	Project 2010-11 TOP-002-2a TPL Table 1 Removing Exhibit, m	Initial Ballot	11/27/2010	1/6/2011	Quorum: 94.41% Approval: 96.36%			
160	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-002-4,	Initial Ballot	12/16/2010	1/6/2011	Quorum: 93.65% Approval: 72.09%	Oppose 12/16/11		
161	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-003-4,	Initial Ballot	12/16/2010	1/6/2011	Quorum: 93.65% Approval: 72.09%	Oppose 12/16/11		
162	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-004-4,	Initial Ballot	12/16/2010	1/6/2011	Quorum: 93.65% Approval: 72.09%	Oppose 12/16/11		
163	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-005-4,	Initial Ballot	12/16/2010	1/6/2011	Quorum: 93.65% Approval: 72.09%	Oppose 12/16/11		
164	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-006-4,	Initial Ballot	12/16/2010	1/6/2011

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https://sbsportal.nerc.net/Pages/Login.aspx
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Line	Project	Ballot Type	Start Date	End Date (Actual Ballot Window Closed)	Ballot Results	Recommendation / Date	Have NERC Voted	Comments
167	Project 2008-06 - Cyber Security - Order 706- CIP-008-1	Initial Ballot	11/14/2013	1/6/2014	Quorum: 93.21% Approval: 89.47%	Approve 11/14/13		
168	Project 2008-06 - Cyber Security - Order 706- CIP-010-1,	Initial Ballot	11/14/2013	1/6/2014	Quorum: 93.21% Approval: 91.51%	Approve 11/14/13		
169	Project 2008-06 - Cyber Security - Order 706- CIP-011-1,	Initial Ballot	11/14/2013	1/6/2014	Quorum: 93.21% Approval: 91.88%	Approve 11/14/13		
170	Project 2008-06 - Cyber Security - Order 706- CIP-10 Implementation,	Initial Ballot	11/14/2013	1/6/2014	Quorum: 92.21% Approval: 91.51%	Approve 11/14/13		
171	Project 2008-06 - Cyber Security - Order 706- CIP-10 Definitions,	Initial Ballot	11/14/2013	1/6/2014	Quorum: 92.36% Approval: 91.64%	Approve 11/14/13		
172	Project 2010-03 TOP-004 TOP-1A	Initial Ballot	12/30/2013	3/3/2014	Quorum: 92.14% Approval: 92.14%			
173	Project 2010-10 FAC-010& FAC-11	Reinvitation Ballot	12/4/2013	1/6/2014	Quorum: 90.81% Approval: 68.86%			
174	Project 2010-11 TPL-TOP-1 Footnote b Ref. 2	Reinvitation Ballot	1/6/2014	1/5/2015	Quorum: 89.75% Approval: 85.79%	Support n/a/11		
175	Project 2010-13.1 - Relay Loadability Order 733 - PRC-023	Successive Ballot	1/16/2015	2/14/2015	Quorum: 83.81% Approval: 77.58%	Support 2/13/15		
176	Project 2007-23 - Violation Severity Levels	Non-binding Poll	1/8/2015	2/12/2015	Quorum: 78.66% Approval: 73.00%	Support 2/12/15		
177	Project 2007-07 Vegetation Management- FAC-003-3	Successive Ballot	2/18/2015	2/28/2015	Quorum: 74.28% Approval: 71.43%	Support 2/27/15		
178	Project 2010-13.1 - Relay Loadability Order 733 - PRC-023	Reinvitation Ballot	2/16/2015	3/6/2015	Quorum: 87.21% Approval: 80.83%	Support 2/27/15		
179	Project 2008-06 - Reliability Coordination - COM-001-1(NAN-035), IRO-001, and IRO-014	Initial Ballot	2/25/2015	3/7/2015	Quorum: 87.21% Approval: 69.54%	Abstain 3/3/15		
180	Project 2010-13 - Expedited Action Revisions to CIP-002-4	Successive Ballot	4/28/2015	4/28/2015	Quorum: 79.66% Approval: 79.66%	Approve 4/28/15		
181	Project 2009-06 - Facility Ratings- FAC-008-3	Initial Ballot	4/21/2015	5/4/2015	Quorum: 88.81% Approval: 68.74%	Abstain 4/28/15		
182	Project 2009-06 - Facility Ratings- FAC-008-3	Non-binding Poll	4/21/2015	5/2/2015	Quorum: 88.81% Approval: 73.00%			
183	Project 2007-17 - Protection System Maintenance and Testing- PRC-005	Successive Ballot	5/6/2015	5/21/2015	Quorum: 79.21% Approval: 65.09%	No Recommendation		
184	Project 2007-17 - Protection System Maintenance and Testing- PRC-005	Non-binding Poll	5/6/2015	5/15/2015	Quorum: 77.09% Approval: 65.09%			
185	Project 2009-06 - Facility Ratings- FAC-008-3	Reinvitation Ballot	5/12/2015	5/23/2015	Quorum: 91.21% Approval: 72.83%	Support 5/22/15		
186	Project 2008-02 - Assoc Transmission and Future Needs - TPL-001-Xreqts TPL-004	Successive Ballot	5/18/2015	5/31/2015	Quorum: 92.07% Approval: 73.90%			
187	Project 2008-02 - Assoc Transmission and Future Needs - TPL-001-Xreqts TPL-004	Non-binding Poll	5/18/2015	5/31/2015	Quorum: 88.79% Approval: 73.90%			
188	Project 2007-03 - Real-time Operations- TOP-001-2, TOP-002-4 and TOP-003-2	Initial Ballot	5/5/2015	5/14/2015	Quorum: 88.87% Approval: 68.04%	Oppose 5/31/15		
189	Project 2007-03 - Real-time Operations- TOP-001-2, TOP-002-4 and TOP-003-2	Non-binding Poll	5/5/2015	6/4/2015	Quorum: 87.00% Approval: 61.80%			
190	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Reinvitation Ballot	6/30/2015	6/30/2015	Quorum: 81.87% Approval: 64.71%	Support 6/30/15		
191	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	Non-binding Poll	6/30/2015	6/30/2015	Quorum: 72.82% Approval: 60.00%			
192	Project 2008-02 - Assoc Transmission and Future Needs	Reinvitation Ballot	7/15/2015	7/24/2015	Quorum: 92.21% Approval: 75.67%			
193	Project 2009-06 - Facility Ratings- IRO-001-2	Reinvitation Ballot	7/15/2015	7/24/2015	Quorum: 94.14% Approval: 77.17%	Support 7/24/15		
194	Project 2008-06 - Reliability Coordination - IRO-001-4	Reinvitation Ballot	7/15/2015	7/24/2015	Quorum: 94.21% Approval: 75.17%	Support 7/23/15		
195	Project 2008-06 - Reliability Coordination - IRO-014-3	Reinvitation Ballot	7/15/2015	7/24/2015	Quorum: 94.21% Approval: 76.67%	Support 7/23/15		
196	Project 2009-06 - Facility Ratings- IRO-001-2	Non-binding Poll	7/15/2015	7/24/2015	Quorum: 75.87% Approval: 65.00%			
197	Project 2008-06 - Reliability Coordination - IRO-001-4	Non-binding Poll	7/15/2015	7/24/2015	Quorum: 75.87% Approval: 72.00%			
198	Project 2008-06 - Reliability Coordination - IRO-014-3	Non-binding Poll	7/15/2015	7/24/2015	Quorum: 75.87% Approval: 73.87%			
199	Project 2007-09 - Generator Verification- MOD-026-1	Initial Ballot	7/22/2015	8/12/2015	Quorum: 89.25% Approval: 46.51%	No Consensus 7/28/15		
200	Project 2007-09 - Generator Verification- MOD-027-1	Non-binding Poll	7/22/2015	8/12/2015	Quorum: 89.75% Approval: 46.51%			
201	Project 2007-09 - Generator Verification- PRC-019-1	Initial Ballot	7/22/2015	8/12/2015	Quorum: 89.87% Approval: 58.22%	No Consensus 7/28/15		
202	Project 2007-09 - Generator Verification- PRC-024-1	Non-binding Poll	7/22/2015	8/12/2015	Quorum: 89.75% Approval: 60.70%			
203	Project 2007-17 - Protection System Maintenance and Testing- PRC-005	Initial Ballot	9/29/2015	10/9/2015	Quorum: 94.86% Approval: 73.91%	Support 9/29/15		
204	Project 2007-17 - Protection System Maintenance and Testing- PRC-005	Non-binding Poll	9/29/2015	10/9/2015	Quorum: 93.12% Approval: 68.68%			
205	Project 2010-17 - Definition of Bulk Electric System- Definition of BES	Initial Ballot	9/28/2015	10/23/2015	Quorum: 97.58% Approval: 72.28%	No Consensus 10/9/15		
206	Project 2010-17 - Definition of Bulk Electric System- Detailed Information to Support BES Exceptions Request	Initial Ballot	9/28/2015	10/23/2015	Quorum: 96.01% Approval: 83.67%	No Consensus 10/9/15		
207	Project 2007-07 Vegetation Management- FAC-003-3	Successive Ballot	10/6/2015	10/13/2015	Quorum: 88.75% Approval: 86.25%	Support 10/13/15		
208	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Initial Ballot	11/7/2015	11/16/2015	Quorum: 89.21% Approval: 89.21%	Support 11/16/15		
209	Project 2009-22 - Interpretation of COM-002-2 R2 for Hydro One	Initial Ballot	11/6/2015	11/17/2015	Quorum: 91.28% Approval: 91.28%	Support 11/16/15		
210	Project 2010-07 - Generator Requirements at the Transmission Interface FAC-001-1	Initial Ballot	11/9/2015	11/18/2015	Quorum: 89.45% Approval: 89.45%	Support 11/16/15		
211	Project 2010-07 - Generator Requirements at the Transmission Interface FAC-003-4	Initial Ballot	11/9/2015	11/18/2015	Quorum: 90.08% Approval: 90.72%	Support 11/16/15		
212	Project 2010-07 - Generator Requirements at the Transmission Interface FAC-003-4	Initial Ballot	11/9/2015	11/18/2015	Quorum: 89.87% Approval: 89.31%	Support 11/16/15		
213	Project 2010-07 - Generator Requirements at the Transmission Interface PRC-004-4 (i)	Initial Ballot	11/9/2015	11/18/2015	Quorum: 89.29% Approval: 89.29%	Support 11/16/15		
214	Project 2008-12 - Interpretation of CIP-002-1 R1 for Progress Energy	Successive Ballot	11/12/2015	11/21/2015	Quorum: 89.23% Approval: 85.99%	Support 11/16/15		
215	Project 2010-17 - Definition of Bulk Electric System and Implementation Plan	Reinvitation Ballot	11/16/2015	11/25/2015	Quorum: 89.36% Approval: 81.41%	Support 11/25/15		
216	Project 2010-17 - Definition of Bulk Electric System- Detailed Information to Support BES Exceptions Request	Reinvitation Ballot	11/16/2015	11/25/2015	Quorum: 93.01% Approval: 84.51%	Support 11/25/15		
217	Project 2007-12 - Frequency Response- BAL-003-1	Initial Ballot	11/30/2015	12/8/2015	Quorum: 93.45% Approval: 90.81%	Oppose 12/8/15		
218	Project 2007-12 - Frequency Response- BAL-003-1	Non-binding Poll	11/30/2015	12/8/2015	Quorum: 92.87% Approval: 90.99%			
219	Project 2009-01 - Disturbance and Sabotage Reporting- EOP-004-2	Initial Ballot	12/2/2015	12/11/2015	Quorum: 87.27% Approval: 87.27%	Oppose 12/8/15		
220	Project 2009-01 - Disturbance and Sabotage Reporting- EOP-004-2	Non-binding Poll	12/2/2015	12/11/2015	Quorum: 85.25% Approval: 85.25%			
221	Project 2008-12 - Interpretation of CIP-002-1 R1 for Progress Energy	Successive Ballot	12/8/2015	12/18/2015	Quorum: 89.23% Approval: 86.01%	Support 12/16/15		
222	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Reinvitation Ballot	12/15/2015	12/23/2015	Quorum: 90.28% Approval: 90.28%	Support 12/16/15		
223	Project 2009-22 - Interpretation of COM-002-2 R2 for Hydro One	Reinvitation Ballot	12/14/2015	12/23/2015	Quorum: 92.28% Approval: 92.28%	Support 12/16/15		
224	Project 2010-07 - Generator Requirements at the Transmission Interface FAC-001-1	Successive Ballot	12/14/2015	12/23/2015	Quorum: 88.84% Approval: 89.29%	Support 12/16/15		
225	Project 2010-07 - Generator Requirements at the Transmission Interface FAC-003-4	Reinvitation Ballot	12/14/2015	12/23/2015	Quorum: 89.45% Approval: 89.45%	Support 12/16/15		
226	Project 2010-07 - Generator Requirements at the Transmission Interface FAC-003-4	Successive Ballot	12/14/2015	12/23/2015	Quorum: 89.31% Approval: 89.31%	Support 12/16/15		
227	Project 2010-07 - Generator Requirements at the Transmission Interface PRC-004-4 (i)	Successive Ballot	12/14/2015	12/23/2015	Quorum: 88.43% Approval: 88.43%	Support 12/16/15		
228	Project 2007-03 - Real-time Operations- TOP-001-2	Successive Ballot	1/5/2016	1/14/2016	Quorum: 91.21% Approval: 91.21%	Support 1/8/16		
229	Project 2007-03 - Real-time Operations- TOP-002-4	Successive Ballot	1/5/2016	1/14/2016	Quorum: 92.14% Approval: 92.14%	Support 1/8/16		
230	Project 2007-03 - Real-time Operations- TOP-003-2	Successive Ballot	1/5/2016	1/14/2016	Quorum: 92.14% Approval: 92.14%	Support 1/8/16		
231	Project 2010-07 - Generator Requirements at the Transmission Interface FAC-001-1	Non-binding Poll	1/6/2016	1/15/2016	Quorum: 91.21% Approval: 78.91%			
232	Project 2007-03 - Real-time Operations- TOP-001-2	Non-binding Poll	1/6/2016	1/15/2016	Quorum: 92.07% Approval: 79.41%			
233	Project 2007-03 - Real-time Operations- TOP-002-4	Non-binding Poll	1/6/2016	1/15/2016	Quorum: 92.07% Approval: 67.21%			
234	Project 2007-03 - Real-time Operations- TOP-003-2	Non-binding Poll	1/6/2016	1/15/2016	Quorum: 92.50% Approval: 77.49%			
235	Project 2008-06 - Reliability Coordination - COM-001-2	Successive Ballot	1/26/2016	2/5/2016	Quorum: 92.83% Approval: 14.66%	Oppose 2/5/16		
236	Project 2008-06 - Reliability Coordination - COM-002-3	Successive Ballot	1/26/2016	2/5/2016	Quorum: 92.21% Approval: 14.66%	Support 2/5/16		
237	Project 2008-06 - Reliability Coordination - IRO-001-4	Successive Ballot	1/26/2016	2/5/2016	Quorum: 92.87% Approval: 85.21%	Support 2/5/16		
238	Project 2008-06 - Reliability Coordination - COM-001-2	Non-binding Poll	1/26/2016	2/5/2016	Quorum: 91.21% Approval: 11.83%			
239	Project 2008-06 - Reliability Coordination - COM-002-3	Non-binding Poll	1/26/2016	2/5/2016	Quorum: 90.06% Approval: 11.83%			
240	Project 2008-06 - Reliability Coordination - IRO-001-4	Non-binding Poll	1/26/2016	2/5/2016	Quorum: 79.77% Approval: 64.28%			
241	Project 2009-06 - Facility Ratings- IRO-001-2	Non-binding Poll	1/26/2016	2/5/2016	Quorum: 79.77% Approval: 64.28%			
242	Project 2009-22 - Interpretation of CIP-002-1 for Hydro One	Successive Ballot	2/1/2016	2/10/2016	Quorum: 92.21% Approval: 92.21%	Support 2/10/16		
243	Project 2011-INT-02 - Interpretation of CIP-002-1 for ConocoPhillips	Initial Ballot	2/1/2016	2/10/2016	Quorum: 90.57% Approval: 83.09%	Support 2/10/16		
244	Project 2007-09 - Generator Verification- MOD-026-1	Successive Ballot	2/9/2016	2/18/2016	Quorum: 85.45% Approval: 85.45%			
245	Project 2007-09 - Generator Verification- PRC-024-1	Successive Ballot	2/9/2016	2/18/2016	Quorum: 86.48% Approval: 86.48%			
246	Project 2007-17 - Protection System Maintenance and Testing- PRC-005	Successive Ballot	2/9/2016	2/19/2016	Quorum: 94.42% Approval: 73.91%	Support 2/17/16		
247	Project 2007-17 - Protection System Maintenance and Testing- PRC-005	Non-binding Poll	2/9/2016	2/19/2016	Quorum: 92.32% Approval: 68.61%			
248	Project 2010-07 - Generator Requirements at the Transmission Interface FAC-003-4	Successive Ballot	2/9/2016	4/8/2016	Quorum: 89.18% Approval: 89.18%	Support 4/8/16		
249	Project 2010-07 - Generator Requirements at the Transmission Interface PRC-004-4	Successive Ballot	3/8/2016	4/8/2016	Quorum: 89.16% Approval: 89.16%	Support 4/8/16		
250	Project 2007-09 - Generator Verification- MOD-025-2	Initial Ballot	4/6/2016	4/15/2016	Quorum: 88.45% Approval: 87.39%	Oppose 4/15/16		
251	Project 2007-09 - Generator Verification- MOD-027-1	Initial Ballot	4/6/2016	4/15/2016	Quorum: 88.45% Approval: 88.45%	Support 4/15/16		
252	Project 2007-09 - Generator Verification- PRC-019-2	Initial Ballot	4/6/2016	4/15/2016	Quorum: 88.45% Approval: 88.45%	Support 4/15/16		
253	Project 2007-09 - Generator Verification- MOD-025-2	Non-binding Poll	4/6/2016	4/15/2016	Quorum: 84.81% Approval: 84.81%			
254	Project 2007-09 - Generator Verification- MOD-027-1	Non-binding Poll	4/6/2016	4/15/2016	Quorum: 84.81% Approval: 84.81%			
255	Project 2007-09 - Generator Verification- PRC-019-2	Non-binding Poll	4/6/2016	4/15/2016	Quorum: 84.81% Approval: 84.81%			
256	Project 2010-07 - Generator Requirements at the Transmission Interface PRC-005-1.1a	Initial Ballot	4/6/2016	4/16/2016	Quorum: 89.85% Approval: 89.85%	Support 4/15/16		
257	Project 2007-03 - Real-time Operations- TOP-001-2	Successive Ballot	4/21/2016	4/29/2016	Quorum: 92.14% Approval: 92.14%	Support 4/29/16		
258	Project 2007-03 - Real-time Operations- TOP-002-4	Successive Ballot	4/21/2016	4/29/2016	Quorum: 93.07% Approval: 93.07%	Support 4/29/16		
259	Project 2007-03 - Real-time Operations- TOP-003-2	Successive Ballot	4/21/2016	4/29/2016	Quorum: 93.07% Approval: 93.07%	Support 4/29/16		
260	Project 2007-03 - Real-time Operations- TOP-001-2	Non-binding Poll	4/21/2016	4/29/2016	Quorum: 92.14% Approval: 78.91%			
261	Project 2007-03 - Real-time Operations- TOP-002-4	Non-binding Poll	4/21/2016	4/29/2016	Quorum: 92.14% Approval: 77.49%			
262	Project 2009-06 - Facility Ratings- IRO-001-2	Successive Ballot	4/26/2016	4/29/2016	Quorum: 92.83% Approval: 92.83%	Support 4/29/16		
263	Project 2010-INT-01 - Interpretation of MOD-028 for NWPP	Initial Ballot	4/26/2016	5/5/2016	Quorum: 87.64% Approval: 87.64%	Support 5/5/16		
264	Project 2007-09 - Generator Verification- PRC-024-1	Successive Ballot	4/26/2016	5/5/2016	Quorum: 86.48% Approval: 86.48%			
265	Project 2007-09 - Generator Verification- MOD-025-2	Successive Ballot	4/26/2016	5/5/2016	Quorum: 85.45% Approval: 85.45%			
266	Project 2007-09 - Generator Verification- MOD-027-1	Successive Ballot	4/26/2016	5/5/2016	Quorum: 88.45% Approval: 88.45%			
267	Project 2007-09 - Generator Verification- PRC-019-2	Successive Ballot	4/26/2016	5/5/2016	Quorum: 88.45% Approval: 88.45%			
268	Project 2007-09 - Generator Verification- PRC-024-2	Initial Ballot	4/26/2016	5/5/2016	Quorum: 88.45% Approval: 88.45%			
269	Project 2007-09 - Generator Verification- MOD-026-1	Successive Ballot	4/26/2016	5/5/2016	Quorum: 88.45% Approval: 88.45%			
270	Project 2007-09 - Generator Verification- MOD-027-1	Successive Ballot	4/26/2016	5/5/2016	Quorum: 88.45% Approval: 88.45%			
271	Project 2008-06 - Reliability Coordination - COM-001-2	Successive Ballot	5/2/2016	5/11/2016	Quorum: 92.21% Approval: 14.66%	Oppose 5/11/16		
272	Project 2008-06 - Reliability Coordination - COM-002-3	Successive Ballot	5/2/2016	5/11/2016	Quorum: 92.21% Approval: 14.66%	Support 5/11/16		
273	Project 2008-06 - Reliability Coordination - IRO-001-4	Successive Ballot	5/2/2016	5/11/2016	Quorum: 92.87% Approval: 85.21%	Support 5/11/16		
274	Project 2008-06 - Reliability Coordination - IRO-014-3	Successive Ballot	5/2/2016	5/11/2016	Quorum: 92.87% Approval: 86.58%	Support 5/11/16		
275	Project 2008-06 - Cyber Security - Order 706- CIP-002-5	Successive Ballot	5/2/2016	5/11/2016	Quorum: 92.87% Approval: 87.76%	Abstain 5/11/16		
276	Project 2008-06 - Cyber Security - Order 706- CIP-003-6	Successive Ballot	5/2/2016	5/11/2016	Quorum: 92.21% Approval: 84.21%	Abstain 5/11/16		
277	Project 2008-06 - Cyber Security - Order 706- CIP-004-5	Successive Ballot	5/2/2016	5/11/2016	Quorum: 92.21% Approval: 85.19%	Abstain 5/11/16		
278	Project 2008-06 - Cyber Security - Order 706- CIP-006-6	Successive Ballot	5/2/2016	5/11/2016	Quorum: 92.36% Approval: 84.21%	Abstain 5/11/16		
279	Project 2008-06 - Cyber Security - Order 706- CIP-009-6	Successive Ballot	5/2/2016	5/11/2016	Quorum: 92.28% Approval: 84.21%	Abstain 5/11/16		
280	Project 2008-06 - Cyber Security - Order 706- CIP-10 Implementation,	Successive Ballot	5/2/2016	5/11/2016	Quorum: 92.21% Approval: 84.21%	Abstain 5/11/16		
281	Project 2008-06 - Cyber Security - Order 706- CIP-10 Definitions,	Successive Ballot	5/2/2016	5/11/2016	Quorum: 90.85% Approval: 87.88%	Abstain 5/11/16		
282	Project 2009-01 - Disturbance and Sabotage Reporting- EOP-004-2	Successive Ballot	5/24/2016	5/24/2016	Quorum: 85.25% Approval: 85.25%			
283	Project 2009-01 - Disturbance and Sabotage Reporting- EOP-004-2	Non-binding Poll	5/24/2016	6/24/2016	Quorum: 79.91% Approval: 79.91%			
284	Project 2007-02 Operating Personnel Protocols- COM-003-1	Initial Ballot	6/22/2016	6/30/2016	Quorum: 93.14% Approval: 91.13%	Oppose 6/30/16		
285	Project 2007-02 Operating Personnel Protocols- COM-003-1	Non-binding Poll	6/22/2016	6/30/2016	Quorum: 92.14% Approval: 88.86%			
286	Project 2007-17 Protection System Maintenance and Testing- PRC-005	Successive Ballot	6/28/2016	6/27/2016	Quorum: 79.44% Approval: 73.00%			
287	Project 2007-17 Protection System Maintenance and Testing- PRC-005	Non-binding Poll	6/28/2016	6/27/2016	Quorum: 73.00% Approval: 70.21%			
288	Project 2011-INT-02 - Interpretation of VAR-002-3a for ConocoPhillips	Initial Ballot	6/28/2016	7/7/2016	Quorum: 89.87% Approval: 89.87%	Support 6/30/16		
289	Project 2007-06 - System Protection Coordination- PRC-027-1	Initial Ballot	6/24/2016	7/6/2016	Quorum: 89.29% Approval: 83.64%	Oppose 6/27/16		
290	Project 2007-06 - System Protection Coordination- PRC-027-1	Non-binding Poll	6/24/2016	7/6/2016	Quorum: 87.29% Approval: 81.64%			
291	Project 2008-06 - Reliability Coordination - COM-001-2	Successive Ballot	6/27/2016	7/6/2016	Quorum: 92.21% Approval: 85.71%			
292	Project 2008-06 - Reliability Coordination - IRO-001-4	Reinvitation Ballot	6/27/2016	7/6/2016	Quorum: 94.21% Approval: 88.21%			
293	Project 2008-06 - Reliability Coordination - COM-002-3	Non-binding Poll	6/27/2016	7/6/2016	Quorum: 84.28% Approval: 84.28%			
294	Project 2008-06 - Reliability Coordination - IRO-001-4	Non-binding Poll	6/27/2016	7/6/2016	Quorum: 89.87% Approval: 86.81%			
295	Project 2008-06 - Reliability Coordination - COM-001-2	Successive Ballot	6/27/2016	7/6/2016	Quorum: 92.21% Approval: 77.50%	No Consensus 7/6/16		
296	Project 2008-06 - Reliability Coordination - COM-002-3	Non-binding Poll	6/27/2016	7/6/2016	Quorum: 79.21% Approval: 79.21%			
297	Project 2011-INT-02 - Interpretation of VAR-002-3a for ConocoPhillips	Reinvitation Ballot	7/18/2016	7/27/2016	Quorum: 93.57% Approval: 89.81%	Support 6/28/16		
298	Project 2011-INT-02 - Rapid Revision of VAR-002-3a for ConocoPhillips	Non-binding Poll	7/18/2016	7/27/2016	Quorum: 93.57% Approval: 89.81%			
299	Project 2010-INT-01 - Rapid Revision of TOP-004-3a for NWPP	Initial Ballot	7/20/2016	7/29/2016	Quorum: 89.89% Approval: 78.38%	Oppose 7/29/16		
300	Project 2010-INT-01 - Rapid Revision of TOP-004-3a for NWPP	Non-binding Poll	7/20/2016	7/29/2016	Quorum: 89.89% Approval: 76.07%			
301	Project 2012-08 IRO-1 - Phase 1 of Glossary Update- Statutory Definitions	Initial Ballot	7/26/2016	8/5/2016	Quorum: 83.11% Approval: 83.11%	Oppose 8/5/16		
302	Project 2007-17 Protection System Maintenance and Testing- PRC-005	Successive Ballot	8/17/2016	8/27/2016	Quorum: 78.21% Approval: 68.21%	Support 8/27/16		
303	Project 2009-19 - Interpretation of BAL-001 for NWPP Reserve Sharing Group	Successive Ballot	8/23/2016	9/6/2016	Quorum: 79.21% Approval: 79.21%	Support 9/6/16		
304	Project 2010-05.1 - Protection Systems- Phase 1 (Misoperations)- PRC-004-3	Initial Ballot	8/29/2016	9/7/2016	Quorum: 88.71% Approval: 87.08%	Support 9/6/16		
305	Project 2010-05.1 - Protection Systems- Phase 1 (Misoperations)- PRC-004-3	Non-binding Poll	8/29/2016	9/7/2016	Quorum: 87.64% Approval: 87.64%			
306	Project 2008-06 - Reliability Coordination - COM-001-2	Reinvitation Ballot	9/6/2016	9/15/2016	Quorum: 90.21% Approval: 77.50%			
307	Project 2007-02 - Operating Personnel Communications Protocols	Successive Ballot	9/12/2016	9/20/2016	Quorum: 77.79% Approval: 59.57%	Support 9/15/16		
308	Project 2007-02 Operating Personnel Protocols- COM-003-1	Non-binding Poll	9/12/2016	9/20/2016	Quorum: 77.79% Approval: 59.57%			
309	Project 2010-INT-01 - Rapid Revision of TOP-004-3a for NWPP	Successive Ballot	9/12/2016	9/21/2016	Quorum: 89.89% Approval: 89.89%			
310	Project 2009-01 - Disturbance and Sabotage Reporting- EOP-004-2	Successive Ballot	9/14/2016	9/27/2016	Quorum: 93.34% Approval: 93.34%	No Consensus 9/27/16		
311	Project 2009-01 - Disturbance and Sabotage Reporting- EOP-004-2	Non-binding Poll	9/14/2016	9/27/2016	Quorum: 79.91% Approval: 79.91%			
312	Project 2009-19 - Interpretation of BAL-001-0.1a for NWPP Reserve Sharing Group	Reinvitation Ballot	9/28/2016	10/6/2016	Quorum: 89.21% Approval: 89.21%	Support 10/5/16		
313	Project 2008-06 - Cyber Security - Order 706- CIP-002-5	Successive Ballot	10/5/2016	10/25/2016	Quorum: 94.28% Approval: 87.76%	Support 10/24/16		
314	Project 2008-06 - Cyber Security - Order 706- CIP-003-6	Successive Ballot	10/5/2016	10/25/2016	Quorum: 89.27% Approval: 84.50%	Support 10/24/16		
315	Project 2008-06 - Cyber Security - Order 706- CIP-004-5	Successive Ballot	10/5/2016	10/25/2016	Quorum: 89.27% Approval: 85.19%	Support 10/24/16		
316	Project 2008-06 - Cyber Security - Order 706- CIP-006-6	Successive Ballot	10/5/2016	10/25/2016	Quorum: 89.28% Approval: 84.50%	Support 10/24/16		
317	Project 2008-06 - Cyber Security - Order 706- CIP-009-6	Successive Ballot	10/5/2016	10/25/2016	Quorum: 89.28% Approval: 84.50%	Support 10/24/16		
318	Project 2008-06 - Cyber Security - Order 706- CIP-10 Implementation,	Successive Ballot	10/5/2016	10/25/2016	Quorum: 89.21% Approval: 87.76%	Support 10/24/16		
319	Project 2008-06 - Cyber Security - Order 706- CIP-008-6	Successive Ballot	10/5/2016	10/25/2016	Quorum: 89.24% Approval: 84.50%	Support 10/24/16		
320	Project 2008-06 - Cyber Security - Order 706- CIP-10 Definitions,	Successive Ballot	10/5/2016	10/25/2016	Quorum: 89.28% Approval: 85.74%	Support 10/24/16		
321	Project 2008-06 - Cyber Security - Order 706- CIP-011-2	Successive Ballot	10/5/2016	10/25/2016	Quorum: 89.28% Approval: 84.50%	Support 10/24/16		
322	Project 2008-06 - Cyber Security - Order 706- CIP-011-2,	Successive Ballot	10/5/2016	10/25/2016	Quorum: 89.28% Approval: 84.50%	Support 10/24/16		
323	Project 2008-06 - Cyber Security - Order 706- CIP-10 Implementation,	Successive Ballot	10/5/2016	10/25/2016	Quorum: 89.28% Approval: 84.50%	Support 10/24/16		
324	Project 2008-06 - Cyber Security - Order 706- CIP-10 Definitions,	Successive Ballot	10/5/2016	10/25/2016	Quorum: 79.21% Approval: 75.39%	Support 10/24/16		
325	SPM (PR)	Initial Ballot	10/6/2016	10/14/2016	Quorum: 89.21% Approval: 83.21%	Support 10/14/16		
326	ERVs and VSLs	Non-binding Poll	10/19/2016	10/25/2016	Quorum: 79.57% Approval: 79.57%			
327	Project 2007-17 Protection System Maintenance and Testing- PRC-005	Reinvitation Ballot	10/19/2016	10/26/2016	Quorum: 85.28% Approval: 80.21%	Support 10/25/16		
328	Project 2007-09 - Generator Verification- MOD-025-2	Successive Ballot	10/19/2016	10/31/2016	Quorum: 85.45% Approval: 78.50%			
329	Project 2007-09 - Generator Verification- PRC-024-2	Successive Ballot	10/19/2016	10/31/2016	Quorum: 75.04% Approval: 75.04%			
330	Project 2007-09 - Generator Verification- MOD-027-2	Successive Ballot	10/19/2016	10/31/2016	Quorum: 85.45% Approval: 68.11%			
331	Project 2007-09 - Generator Verification- MOD-027-1	Successive Ballot	10/19/2016	10/31/2016	Quorum: 85.45% Approval: 72.34%			
332	Project 2007-09 - Generator Verification- PRC-019-2	Successive Ballot	10/19/2016	10/31/2016	Quorum: 85.87% Approval:

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" causes Ballot to the Ballot Results)	Ballot Type	Start Date	End Date (Actual Close to Midnight)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
103	Project 2007-09	Project 2007-09 Generator Verification_MOD-025-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.68% Approval: 87.5%			
104	Project 2007-09	Project 2007-09 Generator Verification_PRC-019-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 74.49% Approval: 92.72%			
105	Project 2007-09	Project 2007-09 Generator Verification_MOD-027-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 74.49% Approval: 64.24%			
106	Project 2007-09	Project 2007-09 Generator Verification_MOD-027-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 74.06% Approval: 64.24%			
107	Project 2007-09	Project 2007-09 Generator Verification_PRC-024-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 73.51% Approval: 65.63%			
108	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-002-5	Reinitial Ballot	10/26/2012	11/5/2012	Quorum: 85.24% Approval: 78.34%	Support 10/XX/12		
109	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-003-5	Reinitial Ballot	10/26/2012	11/5/2012	Quorum: 85.63% Approval: 83.75%	Support 10/XX/12		
340	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-004-5	Reinitial Ballot	10/26/2012	11/5/2012	Quorum: 85.24% Approval: 85.75%	Support 10/XX/12		
341	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-005-5	Reinitial Ballot	10/26/2012	11/5/2012	Quorum: 85.24% Approval: 84.75%	Support 10/XX/12		
342	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-006-5	Reinitial Ballot	10/26/2012	11/5/2012	Quorum: 85.24% Approval: 85.52%	Support 10/XX/12		
343	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-007-5	Reinitial Ballot	10/26/2012	11/5/2012	Quorum: 84.24% Approval: 84.75%	Support 10/XX/12		
344	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-008-5	Reinitial Ballot	10/26/2012	11/5/2012	Quorum: 85.24% Approval: 85.47%	Support 10/XX/12		
345	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-009-5	Reinitial Ballot	10/26/2012	11/5/2012	Quorum: 85.24% Approval: 84.66%	Support 10/XX/12		
346	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-010-1	Reinitial Ballot	10/26/2012	11/5/2012	Quorum: 85.24% Approval: 84.75%	Support 10/XX/12		
347	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-011-1	Reinitial Ballot	10/26/2012	11/5/2012	Quorum: 85.24% Approval: 85.47%	Support 10/XX/12		
348	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-A- Implementation Plan	Reinitial Ballot	10/26/2012	11/5/2012	Quorum: 85.24% Approval: 84.91%	Support 10/XX/12		
349	Project 2008-06	Project 2008-06 - Cyber Security - Order 706- CIP-C- Definitions	Reinitial Ballot	10/26/2012	11/5/2012	Quorum: 85.67% Approval: 85.11%	Support 10/XX/12		
350	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting EOP-004-2	Reinitial Ballot	10/24/2012	11/5/2012	Quorum: 85.24% 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: 78.81% Approval: 68.75%			
352	Project 2007-12	Project 2007-12 - Frequency Response BAL-003-1	Successive Ballot	10/26/2012	11/6/2012	Quorum: 82.03% Approval: 74.39%	Support 11/XX/12		
353	Project 2010-11	Project 2010-11 TPL Footnote b Initial Ballot October 2012 re	Initial Ballot	11/6/2012	11/16/2012	Quorum: 84.24% Approval: 84.24%			
354	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-002-0a and TPL-004-0 for SPCS	Initial Ballot	11/26/2012	12/6/2012	Quorum: 84.81% Approval: 72.57%	Oppose 12/XX/12		
355	Project 2013-02	Project 2013-02 - Paragraph 81	Initial Ballot	11/30/2012	12/10/2012	Quorum: 84.24% Approval: 84.45%	Support 12/XX/12		
356	Project 2007-02	Project 2007-02 Operating Personnel Protocols CON-003-1	Successive Ballot	11/6/2012	12/13/2012	Quorum: 76.78% Approval: 71.43%	No Consensus 12/XX/12		
357	Project 2007-02	Project 2007-02 Operating Personnel Protocols CON-003-1	Non-binding Poll	11/6/2012	12/13/2012	Quorum: 77.21% Approval: 67.41%			
358	Project 2007-06	Project 2007-06 - System Protection Coordination PRC-027-1	Successive Ballot	11/7/2012	12/17/2012	Quorum: 84.24% Approval: 83.51%	Oppose 11/XX/12		
359	Project 2007-06	Project 2007-06 - System Protection Coordination PRC-027-1	Non-binding Poll	11/7/2012	12/17/2012	Quorum: 75.04% Approval: 71.7%			
360	Project 2012-INT-05	Interpretation 2012-INT-05 CIP-002-3 for OGE	Initial Ballot	12/21/2012	12/31/2012	Quorum: 84.24% Approval: 85.69%	Support 12/XX/12		
361	[Blank]	Standard Footnote Revised Revisions to Implement IRO Recommendations	Successive Ballot	12/21/2012	12/31/2012	Quorum: 84.24% Approval: 84.24%	Support 12/XX/12		
362	Project 2007-09	Project 2007-09 Generator Verification_MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 80.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09 Generator Verification_MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 80.89% Approval: 78.39%			
364	Project 2007-09	Project 2007-09 Generator Verification_MOD-027-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 80.89% Approval: 70.27%			
365	Project 2007-09	Project 2007-09 Generator Verification_PRC-019-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 80.89% Approval: 73.61%			
366	Project 2007-12	Project 2007-12 - Frequency Response BAL-003-1	Successive Ballot	12/12/2012	12/21/2012	Quorum: 80.24% Approval: 73.17%			
367	Project 2007-09	Project 2007-09 - Generator Verification PRC-024-1	Successive Ballot	1/2/2013	1/11/2013	Quorum: 78.36% Approval: 69.31%	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: 77.89% Approval: 67.68%			
369	Project 2010-11	Project 2010-11 Transformer Initial Ballot December 2012 rtr	Successive Ballot	1/3/2013	1/11/2013	Quorum: 85.67% Approval: 84.24%	No Consensus 1/11/13		
370	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves_BAL-002-2	Initial Ballot	1/4/2013	1/14/2013	Quorum: 83.96% Approval: 81.69%	Support 1/11/13		
371	Project 2010-14.2	Project 2010-14.2 - Phase 2 of Balancing Authority Reliability-based Controls: Reserves_BAL-002-2	Non-binding Poll	1/4/2013	1/14/2013	Quorum: 83.27% Approval: 81.27%			
372	Project 2013-02	Project 2013-02 - Paragraph 81	Recirculation Ballot	1/8/2013	1/17/2013	Quorum: 84.66% Approval: 84.21%	Support 1/11/13		
373	Project 2012-INT-05	Interpretation 2012-INT-05 CIP-002-3 for OGE	Recirculation Ballot	1/14/2013	1/23/2013	Quorum: 84.66% Approval: 85.09%	Support 1/11/13		
374	[Blank]	Standard Footnote Revised Revisions to Implement IRO Recommendations	Recirculation Ballot	1/18/2013	1/28/2013	Quorum: 85.95% Approval: 84.66%	Support 1/11/13		
375	Project 2010-11	Project 2010-11 Normalize Ballot Jan 2013 rtr	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 88.03% Approval: 69.81%	No Consensus 1/11/13		
376	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-002a-0 and TPL-004-0 for SPCS	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 85.67% Approval: 72.73%	Oppose 1/11/13		
377	Project 2010-01.1	Project 2010-01.1 Protection Systems_Phase 1 (Requirements) PRC-004-2	Successive Ballot	1/17/2013	1/26/2013	Quorum: 77.42% Approval: 59.06%	Support N/A/12		
378	Project 2010-01.2	Project 2010-01.2 Protection Systems_Phase 2 (Requirements) PRC-004-2	Non-binding Poll	1/17/2013	1/26/2013	Quorum: 76.84% Approval: 53.69%			
379	Project 2007-09	Project 2007-09 - Generator Verification_PRC-024-1	Successive Ballot	2/15/2013	2/26/2013	Quorum: 79.85% Approval: 68.97%	Support 2/11/13		
380	Project 2007-09	Project 2007-09 - Generator Verification_PRC-024-1	Non-binding Poll	2/15/2013	2/26/2013	Quorum: 79.38% Approval: 66.24%			
381	Project 2010-13.3	Project 2010-13.3 Phase 3 of Relay Loadability: Generation	Initial Ballot	3/1/2013	3/11/2013	Quorum: 84.66% Approval: 74.81%			
382	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Update_Statutory Definitions	Successive Ballot	3/13/2013	3/22/2013	Quorum: 77.48% Approval: 66.27%	No Consensus 3/11/13		NPCC to abstain - international nature of the BES and BPS is not cost- or feasibility-based
383	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for CPS	Initial Ballot	3/13/2013	3/22/2013	Quorum: 84.66% Approval: 87.18%	Support 3/XX/13		
384	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-002-3 for Consumer Trade	Initial Ballot	3/13/2013	3/22/2013	Quorum: 84.51% Approval: 84.51%	Support 3/XX/13		
385	Project 2007-09	Project 2007-09 - Generator Verification_PRC-024-1	Recirculation Ballot	3/18/2013	3/27/2013	Quorum: 85.23% Approval: 69.64%	Support 3/11/13		
386	Project 2007-02	Project 2007-02 Operating Personnel Protocols CON-003-1	Successive Ballot	3/27/2013	4/5/2013	Quorum: 79.29% Approval: 67.16%	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 with comments and/or abstain. Comments have been received and are necessary and that existing participants attended the mail list. In recognition of the NERC BOT's expectations that CON-003 will be approved by the industry and filed with FERC for their for approval, NPCC has voted affirmatively and will support the standard, with nothing our concerns.
387	Project 2007-02	Project 2007-02 Operating Personnel Protocols CON-003-1	Non-binding Poll	3/27/2013	4/5/2013	Quorum: 77.27% Approval: 67.32%			
388	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: 88.66% Approval: 66.98%	No Consensus 4/22/13		The majority of NPCC's Balancing Authorities have indicated that they will be standard, however NPCC as the Regional Entity has concerns with the standard. In a draft, that was conducted Thea Field-Kritz have indicated that there would be a large number of DL violations as well as potential for increased ACE violations. Additionally, with the proposed BAAL limits based on Frequency triggers. To that end, NPCC recommends that the NYCC BAs who will have to implement this new requirement, do not support. However, NPCC as the Regional Entity will cast an Abstention.
389	Project 2010-14.2	Project 2010-14.2 - Phase 2 of Balancing Authority Reliability-based Controls: Reserves_BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 89.11% Approval: 62.71%	Oppose 4/22/13		There is a lack of technical justification for the 500 MW limit. Additionally, as noted above, NPCC will submit suggested improvements.
390	Project 2010-14.3	Project 2010-14.3 - Phase 3 of Balancing Authority Reliability-based Controls: Reserves_BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 89.11% Approval: 59.26%	Oppose 4/22/13		Lacuna of large blocks of load are typically served by coincident transmission facilities. Without additional and confirmed adjustments made to generation in order to bring the ACE back to zero, loss of further transmission to serve 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 2010-14.2	Project 2010-14.2 - Phase 2 of Balancing Authority Reliability-based Controls: Reserves_BAL-002-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
393	Project 2010-14.3	Project 2010-14.3 - Phase 3 of Balancing Authority Reliability-based Controls: Reserves_BAL-013-1	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
394	Project 2012-08.2	Project 2012-08.2 - Phase 2 of Glossary Update_Statutory Definitions	Nomination Ballot	4/18/2013	4/29/2013	Quorum: 88.15% Approval: 68.21%	No Consensus 5/7/13		
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 Drafting Team should consider any concerns of significance that would warrant a ballot to be cast in the negative. To recommend 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	5/16/2013	5/24/2013	Quorum: 84.51% Approval: 82.71%			
398	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Non-binding Poll	5/16/2013	5/24/2013	Quorum: 77.21% Approval: 73.7%			
399	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Initial Ballot	7/5/2013	7/15/2013	Quorum: 85.67% Approval: 85.73%			
400	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - CON-003	Successive Ballot	7/10/2013	7/19/2013	Quorum: 76.32% Approval: 68.16%	No Consensus 7/19/13 (Due to the concerns raised over the potential actions by the NERC BOT and FERC as well as the lack of improvement of the standard over the previous versions, NPCC as the Regional Entity will support the standard and submit comments.)		The majority of RSC member organizations support the standard as written however some members have concern that in order to measure compliance with R1, the Transmission Operator's use of Reliability Directives has to be investigated to determine if RC issued directives or approved communication protocols have been violated. Also if was determined that RC communication protocols would have to approved by the RC's Compliance Group. The legal course of protocols aren't approved and casts question on compliance with the protocols. NPCC will be submitting some helpful comments on the proposed plan, and some non-substantive revision to performed prior to the next posting of the revised Non-Consent ballot.
401	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - CON-003	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 76.26% Approval: 67.16%			
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: 85.81% 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: 79.85% Approval: 64.52%			
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: 92.21% Approval: 74.54%	No Consensus 7/25/13		The RSC has not reached a full consensus however the majority are in support. Issues surrounding the ability to support are concern over "hitting limits" more frequently and the potential for BAAL to 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-025-1	Initial Ballot	7/26/2013	8/5/2013	Quorum: 80.05% Approval: 63.64%	Support 8/5/13		
406	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: 89.11% Approval: 71.43%	Support 8/12/13		
407	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		
408	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	8/2/2013	8/12/2013	Quorum: 75.85% Approval: 59.81%			
409	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Initial Ballot	8/16/2013	8/23/2013	Quorum: 76.21% Approval: 77.27%	Support 8/21/13		
410	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Non-binding Poll	8/16/2013	8/23/2013	Quorum: 77.21% Approval: 81.37%			
411	Project 2012-05	Project 2012-05 ATC Revisions (MOD-A) - MOD-001-2	Ballot	8/26/2013	9/26/2013	Quorum: 71.13% Approval: 71.13%	No Consensus 9/25/13		NPCC to support with comments.
412	Project 2012-05	Project 2012-05 ATC Revisions (MOD-A) - MOD-001-2	Non-binding Poll	8/26/2013	9/26/2013	Quorum: 72.08% Approval: 53.29%			
413	Project 2010-01	Project 2010-01 - Training - PER-005-2	Ballot	9/25/2013	9/5/2013	Quorum: 75.21% Approval: 59.43%	No Consensus 9/5/13		NPCC to support with comments. The most contentious issues raised by RSC members was the proposed Applicability definitions and the potential to vastly expand those totaling requirements. The standard is well compliance and that there was no need for a standard, however, these issues should be addressed through other means.
414	Project 2010-01	Project 2010-01 - Training - PER-005-2	Non-binding Poll	9/25/2013	9/5/2013	Quorum: 80.61% Approval: 64.24%			
415	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Ballot	9/25/2013	9/5/2013	Quorum: 81.89% Approval: 41.79%	Oppose 9/5/13		The standard, in the view of the group, has extensive issues including but not limited to, applicability issues, both in the standard and in the NERC Rules of Procedure, and other substantive issues. NPCC will be submitting detailed comments on the Ballot Body Vote. The RSC does not believe it would be beneficial to submit a revised ballot at this point in the next step, if it has non-trivial edits, would still support the standard, and plan to be moving to reinitialization due to the substantive changes that have been made. In addition, NPCC will be providing helpful comments to NERC and FERC during the drafting team effort.
416	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Non-binding Poll	9/25/2013	9/5/2013	Quorum: 79.91% Approval: 41.24%			
417	Project 2010-01	Project 2010-01 - Modeling Data (MOD-A) - MOD-032-1, MOD-033-1	Ballot	9/26/2013	9/6/2013	Quorum: 82.25% Approval: 61.24%	Support 8/XX/13		
418	Project 2010-03	Project 2010-03 - Modeling Data (MOD-B) - MOD-032-1, MOD-033-1	Non-binding Poll	9/26/2013	9/6/2013	Quorum: 81.42% Approval: 49.69%			
419	Project 2010-04	Project 2010-04 - Demand Data (MOD-C) - MOD-031-1	Ballot	9/26/2013	9/6/2013	Quorum: 81.96% Approval: 61.24%	Support 8/XX/13		
420	Project 2010-04	Project 2010-04 - Demand Data (MOD-C) - MOD-031-1	Non-binding Poll	9/26/2013	9/6/2013	Quorum: 80.61% Approval: 58.97%			
421	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	9/26/2013	9/6/2013	Quorum: 79.89% Approval: 84.11%	Support 8/XX/13		
422	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves_ Bal-002-2, BAL-001-2	Initial Ballot	9/26/2013	9/16/2013	Quorum: 84.45% Approval: 90.83%	Support 8/XX/13		
423	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves_ Bal-002-2, BAL-001-2	Non-binding Poll	9/26/2013	9/16/2013	Quorum: 79.28% Approval: 72.08%			
424	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for CPS	Final Ballot	9/11/2013	9/20/2013	Quorum: 84.24% Approval: 88.41%	Support 9/XX/13		
425	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-002-3 for Consumer Trade	Final Ballot	9/11/2013	9/20/2013	Quorum: 84.45% Approval: 88.73%	Support 9/XX/13		
427	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Additional Ballot	10/9/2013	10/21/2013	Quorum: 77.28% Approval: 68.72%	Support 10/XX/13		
428	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	10/9/2013	10/21/2013	Quorum: 76.74% Approval: 65.04%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballots.aspx (clicking in the column to the right of "Ballot Period" causes links to the Ballot Results)	Ballot Type	Start Date	End Date (Actual, or Planned if Extended)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
429	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Removing Relays) - PRC-005-3	Final Ballot	04/04/2013	04/05/2013	Quorum: 85.71% Approval: 75.61%			
430	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	04/18/2013	04/29/2013	Quorum: 79.22% Approval: 72.16%	Support 10/21/13		
431	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Final Ballot	04/25/2013	05/14/2013	Quorum: 79.22% Approval: 61.97%			
432	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	04/25/2013	05/17/2013	Quorum: 78.57% Approval: 78.57%	No Consensus 11/13/13		
433	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	5/13/2013	5/22/2013	Quorum: 79.22% Approval: 66.88%	Support 11/13/13		
434	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - IRT-003-2	Initial Ballot	5/14/2013	5/23/2013	Quorum: 79.22% Approval: 67.53%	Support 11/6/13		
435	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - IRT-003-2	Initial Ballot	5/14/2013	5/23/2013	Quorum: 79.22% Approval: 72.73%	Support 11/6/13		
436	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - IRT-003-2	Initial Ballot	5/14/2013	5/23/2013	Quorum: 79.22% Approval: 68.83%	Support 11/6/13		
437	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - IRT-003-2	Initial Ballot	5/14/2013	5/23/2013	Quorum: 79.22% Approval: 68.83%	Support 11/6/13		
438	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - IRT-003-2	Initial Ballot	5/14/2013	5/23/2013	Quorum: 79.22% Approval: 72.73%	Support 11/6/13		
439	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - Definition	Initial Ballot	5/14/2013	5/23/2013	Quorum: 79.87% Approval: 77.92%	Support 11/6/13		
440	Project 2010-07	Project 2010-07 - Definition of Bulk Electric System (Phase 3)	Final Ballot	5/14/2013	5/24/2013	Quorum: 81.82% Approval: 64.94%	Support 10/21/13		
441	Project 2012-05	Project 2012-05 ATC Revisions (MOD-01, MOD-28) 2	Additional Ballot	5/14/2013	5/23/2013	Quorum: 81.69% Approval: 81.69%	No Consensus 11/6/13		
442	Project 2010-05	Project 2010-05 - Modeling Data (MOD-32, MOD-33) 5	Additional Ballot	5/14/2013	5/23/2013	Quorum: 79.87% Approval: 79.87%	Support 8/21/13		
443	Project 2010-05	Project 2010-05 - Modeling Data (MOD-32, MOD-33) 5	Additional Ballot	5/14/2013	5/23/2013	Quorum: 79.87% Approval: 69.81%	Support 8/21/13		
444	Project 2010-04	Project 2010-04 - Demand Data (MOD-17, MOD-20) 6	Additional Ballot	5/14/2013	5/23/2013	Quorum: 80.54% Approval: 80.54%	Support 8/21/13		
445	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Additional Ballot	5/15/2013	5/24/2013	Quorum: 80.87% Approval: 68.18%			
446	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	5/15/2013	5/24/2013	Quorum: 80.87% Approval: 69.48%			
447	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2	Additional Ballot	5/2/2013	5/23/2013	Quorum: 75.29% Approval: 64.12%	No Consensus 11/6/13	affirmative	
448	Project 2007-11	Project 2007-11 Disturbance Monitoring - PRC-002-2	Initial Ballot	5/14/2013	5/24/2013	Quorum: 82.25% Approval: 62.25%	No Consensus 11/21/13	Affirmative	Highlights of comments received: • Agreement with the requirements and Guidelines BES Gradient for which data fail to be captured • Clarification on the "locations" • COM for Paragraphs. WCo • Clarification needed for some terms in the Guidelines • Editorial suggestions
449	Project 2010-05	Project 2010-05 - Modeling Data (MOD-32, MOD-33) 5	Final Ballot	5/28/2013	6/26/2013	Quorum: 87.53% Approval: 87.53%	Support 11/6/13	Affirmative	
450	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - IRT-004-3	Final Ballot	5/15/2013	5/24/2013	Quorum: 80.87% Approval: 80.77%	Support 11/6/13	Affirmative	
451	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - IRT-005-3	Final Ballot	5/15/2013	5/24/2013	Quorum: 80.87% Approval: 77.92%	Support 11/6/13	Affirmative	
452	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - IRT-006-3	Final Ballot	5/15/2013	5/24/2013	Quorum: 84.78% Approval: 84.78%	Support 11/6/13	Affirmative	
453	Project 2012-05	Project 2012-05 ATC Revisions (MOD-01, MOD-28) 2	Final Ballot	5/15/2013	5/24/2013	Quorum: 87.32% Approval: 86.48%	No Consensus 8/29/13	Affirmative	
454	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-4	Final Ballot	5/15/2013	5/24/2013	Quorum: 87.32% Approval: 76.92%		Affirmative	
455	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-027-1	Additional Ballot	5/28/2013	6/6/2013	Quorum: 79.86% Approval: 79.86%	No Consensus 11/6/13	Affirmative	
456	Project 2010-03	Project 2010-03 - Modeling Data (MOD-25, MOD-033) 5	Additional Ballot	5/30/2013	6/5/2013	Quorum: 79.91% Approval: 65.41%	Support 8/21/13	Affirmative	
457	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	5/8/2013	5/22/2013	Quorum: 79.87% Approval: 79.87%	Support 11/13/13	Affirmative	
458	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - IRT-003-3	Additional Ballot	5/30/2013	6/21/2013	Quorum: 75.21% Approval: 75.21%	Support 11/6/13	Affirmative	
459	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - IRT-003-3	Additional Ballot	5/30/2013	6/21/2013	Quorum: 75.21% Approval: 66.19%	Support 11/6/13	Affirmative	
460	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - Definition	Additional Ballot	5/30/2013	6/28/2013	Quorum: 75.97% Approval: 69.17%	Support 11/6/13	Affirmative	
461	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	5/31/2013	6/6/2013	Quorum: 79.91% Approval: 79.91%	No Consensus 11/13/13	Affirmative	Ballot Period Extended to 6/14/13
462	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - IRT-003-3	Final Ballot	5/27/2013	6/6/2013	Quorum: 84.84% Approval: 83.44%	Support 11/6/13	Affirmative	
463	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - IRT-003-3	Final Ballot	5/27/2013	6/6/2013	Quorum: 84.84% Approval: 84.51%	Support 11/6/13	Affirmative	
464	Project 2010-03	Project 2010-03 - Modeling Data (MOD-25, MOD-033) 5	Final Ballot	5/27/2013	6/6/2013	Quorum: 82.25% Approval: 82.25%	Support 8/21/13	Affirmative	
465	Project 2010-01	Project 2010-01 - Training - PER-005-2	Final Ballot	5/27/2013	6/6/2013	Quorum: 84.42% Approval: 77.06%	Support 11/13/13	Affirmative	
466	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - Definition	Final Ballot	5/31/2013	6/10/2013	Quorum: 84.42% Approval: 80.52%	Support 11/6/13	Affirmative	
467	Project 2010-05.1	Project 2010-05.1 - Protection Systems: Phase 1 (Requirements)- PRC-004-3	Additional Ballot	6/1/2013	6/6/2013	Quorum: 79.86% Approval: 79.86%	Support 8/29/13	Affirmative	Ballot Period Extended to 6/17/13
468	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Final Ballot	6/28/2013	6/7/2013	Quorum: 79.21% Approval: 77.92%	Support 3/26/14	Affirmative	
469	Project 2010-04	Project 2010-04 - Demand Data (MOD-17, MOD-020) 6	Additional Ballot	6/1/2013	6/10/2013	Quorum: 80.91% Approval: 80.91%	Support 8/21/13	Affirmative	
470	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-3	Additional Ballot	6/4/2013	6/14/2013	Quorum: 79.91% Approval: 79.91%	---	---	
471	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	Initial Ballot	6/20/2014	6/24/2014	Quorum: 85.06% Approval: 85.07%	Support 6/25/14	Abstain	
472	Project 2010-04	Project 2010-04 - Demand Data (MOD-17, MOD-020) 6	Final Ballot	6/6/2013	6/16/	Quorum: 85.06% Approval: 85.06%	Support 6/25/14	Affirmative	
473	Project 2013-04	Project 2013-04 - Voltage and Reactive Control - VAR-001-3, VAR-002-3	Final Ballot	6/13/2013	6/23/14	Quorum: 83.84% Approval: 83.84%	Support 6/30/14	Affirmative	
474	Project 2014-04	Project 2014-04 - Physical Security - CIP-014-1	Final Ballot	7/1/2014	7/11/2014	Quorum: 82.17% Approval: 81.61%	Support 6/25/14	Abstain	
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Initial Ballot	7/8/2014	7/21/2014	Quorum: 84.78% Approval: 84.78%	No Consensus 5/15/14	Yes1	
476	Project 2012-13	Project 2012-13 FAC - Facility Ratings Coordination	Initial Ballot	7/15/2014	7/25/2014	Quorum: 83.87% Approval: 67.74%	Support 5/29/14	Affirmative	
477	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (System Protection Misses) - PRC-005-3	Initial Ballot	7/15/2014	7/25/2014	Quorum: 87.01% Approval: 87.01%	Support	Affirmative	
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of TPL Undefined - Rated Power Ramps	Initial Ballot	6/30/2014	6/9/2014	Quorum: 75.06% Approval: 75.06%	Does not Support- 6/6/14	Negative	
479	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: 84.78% Approval: 84.78%	Support	Affirmative	
480	Project 2010-05.1	Project 2010-05.1 - Protection Systems: Phase 1 (Requirements) - PRC-004	Additional Ballot	9/29/2014	7/9/2014	Quorum: 79.91% Approval: 79.91%	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: 83.12%83.12%83.12% 83.45%83.45%83.45 Approval: 74.68% 69.06% 74% Abstain: 84.17%59.94%87.87% 83.16%83.16%87.87% Approval: 74.82%69.06% 74%	No Consensus- 6/24/14	Affirmative Negative Affirmative Affirmative Affirmative Negative Affirmative Affirmative	Extended to achieve a quorum.
482	Project 2012-13	Project 2012-13 FAC - Facility Ratings Coordination	Final Ballot	8/26/2014	7/9/2014	Quorum: 84.81% Approval: 67.19%	Support- 6/25/14	Affirmative	
483	Project 2014-02	Project 2014-02 CIP Infrastructure Protection Standards Version 5 Revisions Non-ERAI Content 1 http://www.nerc.com/pa/Stand/Pages/Project-2014-02-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/16/2014	Quorum: 84.15%84.49%84.05% 84.15%84.15%84.15 84.49%79.05% --- Approval: 83.12%79.31%79.31% 83.12%83.12%83.12 79.31%79.31%	CIP-002 No CIP-004 Yes CIP-005 Yes CIP-007 Yes CIP-008 Yes CIP-009 Yes CIP-011 Yes Definitions Yes Support- 7/24/14		
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: 84.81% Approval: 84.81%	Support- 7/25/14		
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.61%79.61%84.04% 80.93%80.93% Approval: 79.61%79.61%84.51% 80.58%80.58%	Support- 7/24/14	Affirmative	
486	Project 2012-13	Project 2012-13 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 85.81% Approval: 78.71%		Affirmative	
487	Project 2012-13	Project 2008-12 Undefined Load Shedding (UVLS) & Undefined Islanding Load Shedding (UFLS)	Initial Ballot	9/27/2014	8/8/2014	Quorum: 79.87% Approval: 79.87%		Affirmative	
488	Project 2012-13	Project 2009-01 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.92% Approval: 77.92%		Negative	
489	Project 2014-03	Project 2010-05.1 - Protection Systems: Phase 1 (Requirements) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.92% Approval: 77.92%	Support	Affirmative	
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 81.29% Approval: 81.29%	Support 9/29/14	Affirmative	
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Setting Misses) - PRC-005-3	Additional Ballot	9/4/2014	9/12/2014	Quorum: 84.13% Approval: 78.43%	Support- 6/6/14	Affirmative	
492	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Additional Ballot	9/16/2014	9/25/2014	Quorum: 84.15%84.49%84.05% 84.15%84.15%84.15 84.49%79.05% --- Approval: 83.12%79.31%79.31% 83.12%83.12%83.12 79.31%79.31%	TOP-001-3 Negative TOP-002-4 Affirmative TOP-003-3 Affirmative IRO-001-4 No consensus however the majority indicated an affirmative IRO-002-4 Negative IRO-010-2 No consensus however a majority indicated a Negative and the others indicated abstention IRO-010-2 Affirmative IRO-014-3 Affirmative IRO-017-1 Affirmative Implementation Plan and Definitions Affirmative 5/19/15		
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: 79.94%	Negative- 10/1/14		
494	Project 2010-13.3	Project 2010-13.3 - Phase 3 of TPL Undefined - Rated Power Ramps	Additional Ballot	9/26/2014	10/6/2014	Quorum: 79.01% Approval: 53.61%	Affirmative- 10/1/14		
495	Project 2012-13	Project 2008-12 Undefined Load Shedding (UVLS) & Undefined Islanding Load Shedding (UFLS)	Additional Ballot	9/26/2014	10/6/2014	Quorum: 84.15%84.49%84.05% Approval: 84.15%84.15%84.15	Affirmative- 10/7/14	Affirmative	
496	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	09/5/2014	09/15/2014	Quorum: 85.81% Approval: 85.81%	Affirmative- 10/7/14		
497	Project 2010-05.2	Project 2010-05.2 - Special Protection Systems (Phase 2 of Protection Systems)	Additional Ballot	09/8/2014	09/18/2014	Quorum: 80.84% Approval: 79.74%	Affirmative- 10/7/14		
498	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	09/9/2014	09/18/2014	Quorum: 84.15%84.15% Approval: 84.15%84.15%	Affirmative- 10/14/14		
499	Project 2014-02	Project 2014-02 CIP Infrastructure Protection Standards Version 5 Revisions	Additional Ballot	09/8/2014	09/17/2014	Quorum: 84.15%84.15%84.05% 83.16%83.16%83.16 84.49%79.05% --- Approval: 83.12%79.31%79.31% 83.12%83.12%83.12 79.31%79.31%	CIP-003-6 no consensus CIP-004-6 Affirmative New Definitions Affirmative Updated Definitions Affirmative Implementation Plan Affirmative Version 5 Retention Affirmative Non-binding polls Affirmative	CIP-003-6 and CIP-010-2 Affirmative	
500	Project 2009-03	Project 2009-03 Emergency Operations	Additional Ballot	09/30/2014	10/20/2014	Quorum: 85.81% Approval: 78.71%	Affirmative- 10/17/14		
501	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (IRO-001-4, IRO-002-4, IRO-010-2, two Definitions, and Implementation Plan)	Final Ballot	10/20/2014	10/29/2014	Quorum: 84.15%84.15%84.05% 84.15%84.15%84.15 84.49%79.05% --- Approval: 84.15%79.31%79.31% 84.15%84.15%84.15 79.31%79.31%	Affirmative- 10/27/14		
502	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (TOP-001-3, TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3, and IRO-017-1)	Final Ballot	10/20/2014	10/29/2014	Quorum: 84.15%84.15%84.05% 84.15%84.15%84.15 84.49%84.15% --- Approval: 84.15%79.31%79.31% 84.15%84.15%84.15 79.31%79.31%	Affirmative- 10/27/14		
503	Project 2007-11	Project 2007-11 Disturbance Monitoring	Additional Ballot	09/30/2014	10/21/2014	Quorum: 85.06% Approval: 77.38%	Affirmative- 10/27/14		
504	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	09/30/2014	10/21/2014	Quorum: 84.15%84.15% Approval: 84.15%84.15%	Affirmative- 10/20/14		
505	Project 2014-03	Project 2007-17.3 PRC-005-3 Protection System Maintenance and Testing - Phase 3 (Setting Misses)	Final Ballot	09/29/2014	10/29/2014	Quorum: 88.31% Approval: 87.01%	Affirmative- 10/28/14		
506	Project 2014-03	Project 2008-12 Undefined Load Shedding (UVLS) & Undefined Islanding Load Shedding (UFLS)	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.01% Approval: 84.41%	Affirmative- 10/31/14		
507	Project 2007-11	Project 2007-11 Disturbance Monitoring	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.01% Approval: 81.82%	Affirmative- 10/31/14		
508	Project 2007-11	Project 2010-05.2 Phase 2 of Special Protection Systems	Final Ballot	10/28/2014	11/6/2014	Quorum: 84.41% Approval: 84.41%	Negative- 10/31/14		
509	Project 2007-11	Project 2009-03 Emergency Operations	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.18% Approval: 79.49%	Affirmative- 10/31/14		
510	Project 2007-11	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	10/28/2014	11/6/2014	Quorum: 84.41%84.41%84.58% Approval: 84.41%84.41%84.41%	Affirmative- 10/29/14		
511	Project 2014-03	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Final Ballot	10/28/2014	11/6/2014	Quorum: 84.41%87.01%87.01% 87.18%87.18%87.31% 86.58% Approval: 84.41%84.41%84.84% 84.41%84.41%84.84%	CIP-003-6 no consensus CIP-004-6 Affirmative New Definitions Affirmative Updated Definitions Affirmative Implementation Plan Affirmative Version 5 Retention Affirmative Non-binding polls Affirmative		
512	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	11/6/2014	11/15/2014	Quorum: 79.35% Approval: 79.35%	Affirmative- 11/6/14		
513	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	11/12/2014	11/21/2014	Quorum: 85.81% Approval: 77.42%	Affirmative- 11/21/14		
514	Project 2014-03	Project 2010-13.3 Phase 3 of TPL Undefined - Rated Power Ramps	Additional Ballot	11/14/2014	11/24/2014	Quorum: 79.87% Approval: 53.25%	Affirmative- 11/21/14		
515	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	11/25/2014	12/24/2014	Quorum: 84.17% Approval: 76.81%	Affirmative- 12/12/14		
516	Project 2014-03	Project 2010-13.3 Phase 3 of TPL Undefined - Rated Power Ramps	Final Ballot	12/5/2014	12/24/2014	Quorum: 84.17% Approval: 69.84%	Affirmative- 12/23/14		
517	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Initial Ballots	11/20/2014	12/3/2014	Quorum: 84.04%79.13%79.69% Approval: 84.04%83.51%79.97%	Affirmative- 11/21/14		
518	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	11/19/2014	1/7/2015	Quorum: 85.71% Approval: 85.71%	Affirmative- 1/6/15		
519	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions	Additional Ballot	11/26/2014	1/6/2015	Quorum: 81.11%81.11%81.44% 82.16%82.16%82.16 76%81.11%81.44% Approval: 84.17%56.94%84.51% 84.16%84.16%84.51 76%81.11%81.44%	CIP-003-7 Binding and non-binding polls no consensus CIP-003-7 Definition- Affirmative CIP-004-7 Binding and non-binding polls- Affirmative CIP-010-2 Definition- Affirmative CIP-004-7 Binding and non-binding polls - Affirmative CIP-010-2 Binding and non-binding polls - Affirmative CIP-011-2 Binding and non-binding polls- Affirmative CIP Implementation Plan- Affirmative 5/6/2015		
520	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards - TOP-001-3	Final Ballots	12/5/2014	12/15/2014	Quorum: 84.78% Approval: 72.46%	Affirmative- 1/6/15		
521	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-3	Initial Ballots	12/5/2014	12/15/2014	Quorum: 84.17% Approval: 84.17%	Affirmative- 1/21/15		
522	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-3, Uni. PRC-019-2, and PRC-024-2	Final Ballots	1/5/2015	1/15/2015	Quorum: 84.17%84.16%84.51% Approval: 84.17%84.51%84.51%	Affirmative- 1/21/15		
523	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions CIP-003-7, CIP-004-7, CIP-010-3, and CIP-011-3	Final Ballot	1/15/2015	1/25/2015	Quorum: 84.17%84.16%84.51% 82.16%82.16%82.16 76%81.11%81.44% Approval: 84.17%84.51%84.84% 84.16%84.16%84.51 76%81.11%81.44%	Affirmative- 1/25/15		
524	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-3	Final Ballot	1/6/2015	1/15/2015	Quorum: 83.51% Approval: 83.51%	Affirmative- 1/21/15		
525	Project 2010-14.2	Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	1/8/2015	1/16/2015	Quorum: 79.87% Approval: 53.25%	Negative- 1/21/15/15		
526	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undesignated Load Shedding (UVLS) Disagreements	Initial Ballot	1/27/2015	2/5/2015	Quorum: 79.41% Approval: 79.41%	Affirmative- 2/5/15		
527	Project 2014-04	Project 2014-04 Physical Security	Initial Ballot	2/5/2015	2/9/2015	Quorum: 84.31% Approval: 84.31%	Affirmative- 2/5/15		
528	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undesignated Load Shedding (UVLS) Disagreements	Final Ballot	4/17/2015	4/27/2015	Quorum: 84.41% Approval: 84.41%	Affirmative- 2/5/15		
529	Project 2014-04	Project 2014-04 Physical Security	Final Ballot	4/20/2015	4/29/2015	Quorum: 91.00% Approval: 91.00%	Affirmative- 3/5/15		
530	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	5/8/2015	5/15/2015	Quorum: 81.75% Approval: 69.61%	Negative- 5/21/15/15		
531	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Initial Ballot	6/29/2015	7/8/2015	Quorum: 91.15%84.05% Approval: 84.15%84.15%	Affirmative- 7/7/15		
532	Project 2015-04	2015-04 Alignment of Terms	Initial Ballot	7/17/2015	7/27/2015	Quorum: 84.15%84.15%84.15% 84.15%84.15%84.15 76%81.11%81.44%84.5 84.15%84.15%84.15 76%81.11%81.44%84.5 Approval: 84.15%84.15%84.15% 84.15%84.15%84.15 76%81.11%81.44%84.5	TOP-001-3 Negative TOP-002-4 Affirmative TOP-003-3 Affirmative IRO-001-4 No consensus however the majority indicated an affirmative IRO-002-4 Negative IRO-010-2 No consensus however a majority indicated a Negative and the others indicated abstention IRO-010-2 Affirmative IRO-014-3 Affirmative IRO-017-1 Affirmative Implementation Plan and Definitions Affirmative 5/19/15		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballots.aspx (clicking in the column to the left, right of "Ballot Results" causes links to the Ballot Results)	Ballot Type	Start Date	End Date 24:00 Eastern Standard	Ballot Results	Recommendation / Date	Have NERC Voted	Comments
						Approval: MRO(NR) 17%(4)(1)(0) RF 0%(9)(7) SERC 17%(3)(1)(0)(1) NPCC 0%(3)(2)(0)(0) WECC 0%(5)(3)(0)(0) ISO/RTO Council 0%(5)(3)(0)(0) Segments: 1 - 0%(5)(3)(0)(0) 2 - 0%(2)(1)(0)(0) 3 - 17%(4)(1)(0)(0) 4 - 0%(2)(1)(0)(0) 5 - 0%(5)(3)(0)(0) 6 - 0%(3)(2)(0)(0) 7 - 0%(0)(0)(0)(0) 8 - 0%(2)(1)(0)(0) 9 - 0%(0)(0)(0)(0) 10 - 0%(2)(1)(0)(0) Abstain: MRO(NR) 17%(4)(1)(0) RF 0%(9)(7) SERC 17%(3)(1)(0)(1) NPCC 0%(3)(2)(0)(0) WECC 0%(5)(3)(0)(0) ISO/RTO Council 0%(5)(3)(0)(0) Segments: 1 - 0%(5)(3)(0)(0) 2 - 0%(2)(1)(0)(0) 3 - 17%(4)(1)(0)(0) 4 - 0%(2)(1)(0)(0) 5 - 0%(5)(3)(0)(0) 6 - 0%(3)(2)(0)(0) 7 - 0%(0)(0)(0)(0) 8 - 0%(2)(1)(0)(0) 9 - 0%(0)(0)(0)(0) 10 - 0%(2)(1)(0)(0)		
533	Project 2015-04	2015-04 Interconnection Reliability Operations and Coordination	Final Ballot	7/31/2015	7/31/2015	Approval: RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 17/21		
534	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	8/11/2015	9/25/2015	Approval: MRO(NR) 100%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 8/17/15		
535	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	9/3/2015	9/11/2015	Approval: MRO(NR) 100%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 8/8/15		
536	Project 2007-06	Project 2007-06.2 Phase 2 of System Protection Coordination	Initial Ballot	9/2/2015	9/11/2015	Approval: MRO(NR) 100%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 8/15/15		
537	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls - BAs, DSRs, and BAs, GSRs	Initial Ballot	9/8/2015	9/21/2015	Approval: MRO(NR) 100%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Abstention: 9/14/15		
538	Project 2015-04	2015-04 Alignment of Terms	Final Ballot	9/8/2015	9/14/2015	Approval: MRO(NR) 100%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 7/24/15		
539	Project 2007-17.4	Project 2007-17.4 PRC-005-5(X): Order No. 803 Directive	Initial Ballot	9/9/2015	9/16/2015	Approval: MRO(NR) 100%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 9/16/15		
540	Project 2010-05.1	Project 2010-05.1 PRC-005-1(X): Order No. 803 Directive	Initial Ballot	9/9/2015	9/16/2015	Approval: MRO(NR) 100%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 9/16/15		
541	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Initial Ballot	9/15/2015	10/5/2015	Approval: MRO(NR) 100%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Negative: 10/5/15		
542	Project 2015-05.1	Project 2015-05.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Final Ballot	9/25/2015	10/8/2015	Approval: MRO(NR) 100%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 8/17/15		
543	Project 2007-06	Project 2007-06.2 System Protection Coordination	Final Ballot	9/25/2015	10/13/2015	Approval: MRO(NR) 100%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 9/8/15		
544	Project 2010-05.3	Project 2010-05.3 PRC-005-1(X): Order No. 803 Directive	Final Ballot	9/8/2015	10/13/2015	Approval: MRO(NR) 100%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 9/16/15		
545	Project 2007-17.4	Project 2007-17.4 PRC-005-5(X): Order No. 803 Directive	Final Ballot	10/13/2015	10/26/2015	Approval: MRO(NR) 100%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 9/16/15		
546	Project 2010-05.3	Project 2009-01 Real-time Reliability Monitoring and Analysis Capabilities	Initial Ballot	10/30/2015	11/6/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Abstention: 11/5/15		
547	Project 2010-05.3	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAs, DSRs 2	Initial Ballot	11/3/2015	11/12/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 11/5/15		
548	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Initial Ballot	11/4/2015	11/16/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 11/4/15		
549	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Additional Ballot	11/6/2015	11/16/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 10/30/15		
550	Project 2010-07.1	Project 2010-07.1 Generator Requirements	Initial Ballot	11/7/2015	12/16/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Negative: 12/8/15		
551	Project 2010-14.2.2	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAs, DSRs 2	Final Ballot	11/6/2015	11/17/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 11/5/15		
552	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	11/30/2015	12/8/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 11/30/15		
553	Project 2010-14.2.2	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls - BAs, DSRs, and BAs, GSRs	Additional Ballot	12/1/2015	12/11/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	BAL-005-1 - Negative: 12/11/15 FAC-001 - Affirmative: 12/11/15 FAC-003-3 - Abstention: 12/10/15		
554	Project 2009-01	Project 2009-01 Real-time Reliability Monitoring and Analysis Capabilities	Additional Ballot	12/3/2015	12/11/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 12/5/15		
555	Project 2010-07.1	Project 2010-07.1 Generator Requirements	Final Ballot	12/9/2015	12/18/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 12/8/15		
556	Project 2010-14.2.2	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls - BAs, DSRs, and BAs, GSRs	Final Ballot	12/9/2015	12/18/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 12/5/15		
557	Project 2015-05.1	Project 2015-05.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Final Ballot	12/9/2015	12/21/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 12/9/15		
558	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Final Ballot	12/11/2015	12/21/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 12/9/15		
559	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Initial Ballot	12/16/2015	12/28/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 12/16/15		
560	Project 2015-09	Project 2015-09.1 Phase 1 of Establish and Communicate System Operating Limits	Additional Ballot	12/16/2015	1/5/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 12/16/15		
561	Project 2010-05.3	Project 2009-01 Real-time Reliability Monitoring and Analysis Capabilities	Final Ballot	12/17/2015	12/28/2015	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 12/5/15		
562	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	1/6/2016	1/15/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 12/16/15		
563	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Additional Ballot	1/6/2016	1/15/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 12/16/15		
564	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Final Ballot	1/6/2016	1/15/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 12/16/15		
565	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Additional Ballot	4/27/2016	5/6/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 5/6/16		
566	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Final Ballot	5/2/2016	5/16/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 4/29/16		
567	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Additional Ballot	5/25/2016	6/3/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 5/6/16		
568	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Initial Ballot	5/25/2016	6/6/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 6/3/16		
569	Project 2015-09	Project 2015-09 Emergency Operations EOP-005-3 EOP-006-3 EOP-008-2	Initial Ballot	6/6/2016	6/15/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Negative: 6/9/16		
570	Project 2016-02	Project 2016-02 Modifications to CIP Standards	Initial Ballot	6/6/2016	6/15/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Negative: 6/9/16		
571	Project 2015-09	Project 2015-09 Emergency Operations EOP-005-3 EOP-006-3 EOP-008-2	Final Ballot	6/16/2016	6/27/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 6/24/16		
572	Project 2016-02	Project 2016-02 Modifications to CIP Standards, CIP-002-5.1 Implementation Plan and 2 Definitions	Initial Ballot	6/16/2016	6/25/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 6/23/16		
573	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Initial Ballot	6/24/2016	7/8/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Abstain: 6/8/16		
574	Project 2015-09	Project 2015-09 Emergency Operations EOP-004-4	Final Ballot	6/24/2016	7/5/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 6/8/16		
575	Project 2016-02	Project 2016-02 Modifications to CIP Standards, CIP-002-5.1 Implementation Plan and 2 Definitions	Final Ballot	6/30/2016	7/8/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 6/23/16		
576	IPM	Revisions to the NERC Standards Process Manual	Initial Ballot	6/24/2016	7/8/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Abstain: 7/8/16		
577	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Additional Ballot	6/8/2016	6/21/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 6/8/16		
578	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Final Ballot	7/11/2016	7/20/2016	Approval: MRO(NR) 83%(4)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 6/8/16		
579	Project 2015-03	Project 2015-03 Geomagnetic Disturbance Mitigation TPL-007-2	Initial Ballot	8/22/2017	9/21/2017	Approval: MRO(NR) 75%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 8/25/17		
580	Project 2016-04	Project 2016-04 Modifications to PRC-023-3	Initial Ballot	8/29/2017	9/8/2017	Approval: MRO(NR) 75%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 8/31/17		
581	Project 2016-03	Project 2016-03 Cyber Security Cyber Security Supply Chain Risk Management	Initial Ballot	8/31/2017	9/12/2017	Approval: MRO(NR) 75%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 9/12/17		
582	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Initial Ballot	9/8/2017	10/23/2017	Approval: MRO(NR) 75%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Abstain - 10/18/17		
583	Project 2015-03	Project 2015-03 Geomagnetic Disturbance Mitigation TPL-007-2	Final Ballot	10/20/2017	10/30/2017	Approval: MRO(NR) 75%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 8/25/17		
584	Project 2016-04	Project 2016-04 Modifications to CIP Standards CIP-002-5.1	Initial Ballot	9/14/2017	10/25/2017	Approval: MRO(NR) 75%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 10/20/17		
585	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Initial Ballot	11/2/2017	11/13/2017	Approval: MRO(NR) 75%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 11/13/17		
586	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	11/20/2017	10/31/2017	Approval: MRO(NR) 75%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 11/6/17		
587	Project 2016-04	Project 2016-04 Modifications to PRC-023-3	Additional Ballot	10/26/2017	11/13/2017	Approval: MRO(NR) 75%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 11/6/17		
588	Project 2016-04	Project 2016-04 Modifications to PRC-023-3	Final Ballot	11/6/2018	11/16/2018	Approval: MRO(NR) 75%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 11/6/17		
589	Project 2017-02	Project 2017-02 Modifications to Personnel Performance, Training and Qualifications	Initial Ballot	2/26/2018	3/7/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 3/2/18		
590	Project 2017-02	Project 2017-02 Modifications to Personnel Performance, Training and Qualifications	Final Ballot	4/5/2018	4/12/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 3/2/18		
591	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Additional Ballot	12/13/2018	4/22/2019	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 4/26/18		
592	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Initial Ballot	4/16/2018	4/26/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 4/25/18		
593	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Initial Ballot	4/16/2018	4/26/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 4/25/18		
594	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1 Cyber Security Definition and Implementation Plan	Initial Ballot	5/16/2018	6/26/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Negative: 6/25/18		
595	Project 2017-06	Project 2017-06 Modifications to BAL-002-2	Initial Ballot	6/27/2018	7/6/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Abstain - 6/25/17		
596	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	5/24/2018	7/9/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 6/25/18		
597	Project 2017-06	Project 2017-06 Modifications to BAL-002-2	Final Ballot	7/6/2018	7/16/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Abstain - 6/25/17		
598	IPM	Revisions to the NERC Standards Process Manual	Additional Ballot	7/31/2018	9/6/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 8/31/18		
599	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	8/14/2018	9/13/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 8/31/18		
600	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Additional Ballot	9/5/2018	9/14/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 9/6/18		
601	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Additional Ballot	10/3/2018	10/12/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 10/5/18		
602	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Initial Ballot	9/28/2018	10/8/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 10/5/18		
603	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Additional Ballot	10/8/2018	10/17/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 10/12/18		
604	Project 2018-02	Project 2018-02 Modifications to CIP-002 Cyber Security Incident Reporting	Initial Ballot	10/18/2018	10/25/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Abstain - 10/22/18		
605	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Final Ballot	10/11/2018	10/22/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 9/6/18		
606	IPM	Revisions to the NERC Standards Process Manual	Final Ballot	10/2/2018	10/15/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 9/7/18		
607	Project 2018-01	Project 2018-01 Canadian-specific Revisions to TPL-007-2	Initial Ballot	11/8/2018	11/15/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 11/8/18		
608	Project 2018-02	Project 2018-02 Modifications to CIP-002 Cyber Security Incident Reporting	Additional Ballot	11/20/2018	11/29/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 11/20/18		
609	Project 2018-01	Project 2018-01 Canadian-specific Revisions to TPL-007-2	Final Ballot	11/29/2018	12/10/2018	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 11/8/18		
610	Project 2017-01	Project 2017-01 Modifications to BAL-003-1.1	Initial Ballot	1/8/2019	1/17/2019	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 1/14/19		
611	Project 2018-02	Project 2018-02 Modifications to CIP-002 Cyber Security Incident Reporting	Final Ballot	1/15/2019	1/25/2019	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 11/29/18		
612	Project 2018-03	Project 2018-03 Standards Efficiency Review Retirements	Initial Ballot	4/5/2019	4/15/2019	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 4/15/19 for all standards except three Abstain: 4/15/19 on following standard PRC-004-5(i), IRO-010-2.1 and PRC-0008-3		
613	Project 2018-02	Project 2018-02 Modifications to CIP-002-6	Final Ballot	4/18/2019	4/29/2019	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 10/5/18		
614	Project 2018-03	Project 2018-03 Standards Efficiency Review Retirements	Final Ballot	4/5/2019	4/15/2019	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 4/15/19 for all standards except three.		
615	Project 2018-04	Project 2018-04 Modifications to PRC-024-2	Initial Ballot	5/22/2019	5/31/2019	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Abstain - 5/29/19		
616	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Additional Ballot	5/5/2019	7/15/2019	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 7/15/19		
617	Project 2019-01	Project 2019-01 Modifications to TPL-001-5	Initial Ballot	6/26/2019	7/8/2019	Approval: MRO(NR) 67%(3)(1) RF 100%(9)(7) SERC 100%(4)(1) Abstain: RF 0%(9)(7) SERC 0%(4)(1)	Affirmative: 6/5/19		
618	Project 2017-01	Project

Link to Ballot Results:
https://sbsystems.nerc.net/Ballots.aspx
(clicking in the column to the right of "Ballot Period" causes links to the Ballot Results)

Line	Project	Ballot Type	Start Date	End Date (Actual Close to Closed)	Ballot Results	Recommendation / Date	Have NOT(s) Issued	Comments
612	Project 2018-04	Final Ballot	11/8/2019	11/13/2019	Quorum: 89.31% Approval: 83.47%	Affirmative- 11/6/19		
613	Project 2016-02	Additional Ballot	11/1/2019	12/16/2019	Quorum: 91.83% Approval: 91.83%	Affirmative- 11/1/1/19		
614	Technical Rationale for Reliability Standards	Non-binding Poll	11/8/2019	11/18/2019	Quorum: 81.41%/83.52%&3.85% 84.17%/85.74%&8.51 %BS: 77.63%&83%&7.7 Approval: 84.71%&88.85%&91.22% BS: 77.63%&83%&7.7 %BS 19.62%&77.71%	Affirmative- 11/1/1/19		
615	Project 2017-07	Final Ballot	11/4/2019	12/5/2019	Quorum: 84.11%&89.45%&89.8% 91.66%%91.66%&89.84% Approval: 84.44%%94.69%&94.69% 91.66%%91.66%&94.69% 84.44%&94.69%	Affirmative- 11/1/1/19		
616	Project 2019-02	Initial Ballot	12/4/2019	1/6/2020	Quorum: 84.04%&91.78%&91.58% Approval: 81.57%&93.04%&93.30%	Abstain- 1/6/20		
617	Project 2019-03	Final Ballot	12/7/2019	12/17/2019	Quorum:88.21% Approval: 88.21%	Abstain- 12/6/19		
618	Project 2016-02	Final Ballot	12/6/2019	1/6/2020	Quorum: 87.41% Approval: 91.26%	Affirmative- 11/1/1/19		
619	Technical Rationale for Reliability Standards	Non-binding Poll	4/22/2020	4/30/2020	Quorum: 81.41%&81.41%&81.3% 81.17%&81.41%&81.3% %BS 73% Approval: 84.71%&77.27%&77.22% 85.18%&81.7%&77.13% %BS:83.6%&83.7%&83.7	Affirmative- 4/27/20		
620	Project 2019-03	Additional Ballot	5/12/2020	5/22/2020	Quorum: 79.31% Approval: 79.31%	Abstain- 12/6/19		
621	Project 2015-09	Initial/Additional Ballot	7/24/2020	8/26/2020	Quorum: 81.49%&81.11%&81.35% 81.11%&81.07%&81.08 %BS 73%&73%&73%&73 %BS 49% Approval: 84.34%&86.32%&79.26% 86.36%&72.41%&86.78 %BS 49%&49%&49%&49 %BS 17%	Affirmative- 7/24/20		
622	Project 2019-02	Additional Ballot	9/11/2020	9/21/2020	Quorum: 84.04%&91.45%&91.84% Approval: 72.83%&93.06%&92.69%	Abstain- 9/7/20		
623	Project 2019-02	Final Ballot	10/7/2020	10/16/2020	Quorum:92.02% Approval: 91.72%	Abstain- 12/6/19		
624	Project 2015-09	Additional Ballot	11/27/2020	12/7/2020	Quorum: 81.81%&82.41% Approval: 81.11%&81.75% Abstain: 84.91%&84.41%	Affirmative- 12/4/20		
625	Project 2018-03	Initial Ballot	4/5/2019	4/12/2019	Quorum: 84.04%&91.45%&91.84% Approval: 91.91%%100%	Affirmative- 1/6/21		
626	Project 2018-03	Final Ballot	1/26/2021	2/4/2021	Quorum: 92.26% Approval: 91.96%	Affirmative- 1/6/21		
627	Project 2019-06	Initial Ballot	4/6/2021	4/12/21	Quorum: 84.71%&91.49%&89.81% Approval: 84.19%&91.17%&84.35%	Affirmative- 3/8/21		
628	Project 2016-02	Initial Ballot	6/22/2021	6/21/2021	Quorum: 84.32%&89.94%&91.87% 89.47%&89.87%&90.24 %BS 73%&73%&73%&73 %BS 41%&41%&41% Approval: 84.87%&89.35%&91.17% 84.32%&89.94%&91.32 %BS 49%&49%&49%&49 %BS 22%	Abstain- 6/7/21		
629	Project 2015-09	Additional Ballot	4/29/2021	5/4/2021	Quorum: 81.81%&81.41% Approval: 81.11%&81.75% Abstain: 84.91%&84.41%	Affirmative- 5/31/21		
630	Project 2016-02	Additional Ballot	5/5/2021	5/14/2021	Quorum: 84.71%&89.41%&89.24% Approval: 84.71%&91.39%&92.51%	Abstain- 4/30/21		
631	Project 2019-06	Final Ballot	5/18/2021	5/27/2021	Quorum: 90.63%&89.46%&89.24% Approval: 78.26%&87.39%&87.52%	Affirmative- 5/5/21		
632	Project 2020-04	Initial Ballot	5/26/2021	6/9/2021	Quorum: 83.85%&88.57% Approval: 77.17%&86.72%	Abstain- 6/7/21		
633	Project 2019-02	Additional Ballot	5/27/2021	6/11/2021	Quorum: 84.71%&89.41%&89.87% Approval: 84.19%&90.79%&91.17%	Abstain- 6/30/21		
634	Project 2019-03	Additional Ballot	6/4/2021	6/14/2021	Quorum: 88.21%&88.57% Approval: 77.17%&86.72%	Abstain- 10/7/21		
635	Project 2020-04	Additional Ballot	6/4/2021	6/14/2021	Quorum: 83.85%&88.57% Approval: 77.17%&86.72%	Abstain- 6/9/21		
636	Project 2019-01	Initial Ballot	6/15/2021	6/25/2021	Quorum: 84.04%&91.45%&91.84% Approval: 84.19%&90.79%&91.17%	Abstain- 6/25/21		
637	Project 2019-02	Additional Ballot	6/17/2021	6/21/2021	Quorum:89.31% Approval: 89.31%	Abstain- 12/6/19		
638	Project 2019-02	Final Ballot	10/5/2021	10/15/2021	Quorum: 89.31%&89.94%&91.87% Approval: 84.19%&90.79%&91.17%	Abstain- 10/7/21		
639	Project 2015-09	Additional Ballot	10/6/2021	10/15/2021	Quorum: 81.81%&81.41% Approval: 81.11%&81.75% Abstain: 84.91%&84.41%	Affirmative- 10/6/21		
640	Project 2019-06	Additional Ballot	9/2/2021	9/16/21	Quorum: 87.74%&89.28%&89.24% Approval: 77.17%&86.41%&85.28%	Affirmative- 9/8/21		
641	Project 2015-09	Final Ballot	9/29/2021	5/10/2021	Quorum: 81.81%&81.41%&81.28% 81.41%&81.41%&81.28 %BS 73%&73%&73%&73 %BS 41% Approval: 84.71%&88.16%&91.57% 84.17%&91.01%&91.01 %BS 49%&49%&49%&49 %BS 19%&97.33%&93.3 %BS 19%&97.33%&93.3	Affirmative- 5/31/21		
642	Project 2015-09	Final Ballot	10/25/2021	5/10/2021	Quorum: 92.31% Abstain: 78.95%	Affirmative- 5/31/21		
643	Project 2019-02	Additional Ballot	10/5/2021	5/10/2021	Quorum: 84.11%&84.41%&83.64% Approval: 83.71%&91.39%&92.51%	Affirmative- 4/30/21		
644	Project 2019-06	Final Ballot	5/18/2021	5/27/2021	Quorum: 90.63%&89.46%&89.24% Approval: 78.26%&87.39%&87.52%	Affirmative- 5/5/21		
645	Project 2020-04	Initial Ballot	10/26/2021	5/9/2021	Quorum: 83.85%&88.57% Approval: 77.17%&86.72%	Abstain- 6/7/21		
646	Project 2019-03	Additional Ballot	10/6/2021	10/15/2021	Quorum: 88.21%&88.57% Approval: 77.17%&86.72%	Abstain- 10/7/21		
647	Project 2016-02	Additional Ballot	4/5/2022	4/12/2022	Quorum: 84.71%&89.41%&89.24% Approval: 84.19%&90.79%&91.17%	Abstain- 4/7/22		
648	Project 2020-03	Additional Ballot	2/25/2022	4/15/2022	Quorum: 81.41%&81.41%&81.28% 81.41%&81.41%&81.28% %BS 73%&73%&73%&73 %BS 49% Approval: 72.46%&72.41%&72.22% 85.18%&81.7%&77.13% %BS 19%&83%&83%&83 %BS 19%	Abstain- 4/7/22		
649	Project 2020-05	Additional Ballot	2/25/2022	4/15/2022	Quorum: 83.11%&83.91% Approval: 72.41%&86.72%	Abstain- 4/7/22		
650	Project 2021-07	Initial Ballot	4/4/2022	4/25/2022	Quorum: 84.71%&89.28% Approval: 77.17%&86.72%	Abstain- 4/14/22		
651	Project 2019-06	Initial Ballot	4/7/2022	4/18/2022	Quorum: 90.63%&89.46% Approval: 78.26%&87.39%	Abstain- 4/18/22		
652	Project 2021-04	Initial Ballot	7/15/2022	7/25/2022	Quorum: 90.94%&87.85% Approval: 84.94%&71.85%	Abstain- 7/22/22		

RSC Meeting #23-5, Agenda Item 4.3: Comment History

(As of 11/30/2023)

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

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11
13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11
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

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
25.	N/A	CAN-0024--Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	CAN-0024 CIP-002 through CIP-009		5/20/11	6/10/11	
26.	N/A	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	CAN-0029 PRC-004-1 R1, R2 and R3		5/20/11	6/10/11	
27.	N/A	CAN-0030--Draft CAN-0030 Attestations	CAN-0030 Attestations		5/20/11	6/10/11	
28.	N/A	CAN-0039--Draft CAN-0039 DOE Form 407	CAN-0039 DOE Form 407		5/20/11	6/10/11	
29.	Project 2010-05.1	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)			6/10/11	7/11/11	
30.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-025-2, MOD-027-1, PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		6/15/11	7/15/11	Yes 7/15/11
31.	Project 2010-07	Project 2010-07 – Generator Requirements at the Transmission Interface – Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards		6/17/11	7/17/11	Yes 7/15/11
32.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		6/15/11	8/1/11	Yes 8/1/11
33.	NERC RoP	Proposed Changes to NERC Rules of Procedure and associated Appendices (Appendix 4B – Sanction Guidelines; and Appendix 4C – Compliance Monitoring and Enforcement Program)	Appendices 4B and 4C		6/30/11	8/15/11	
34.	N/A	Compliance Application Notice (CAN) Process	CAN Process		8/15/11	9/6/11	Yes 9/6/11

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
35..	N/A	CAN-0016 CIP-001 R1 - Sabotage Reporting Procedure	CAN-0016 CIP-001, R1		8/15/11	9/6/11	Yes 9/6/11
36.	N/A	DRAFT CANs Posted for Comment and Retirement of CAN-0001 through 0004	CAN-0001 through 0004 Retirement		8/31/11	9/21/11	
37.	NERC RSDP	NERC 2012-2014 Reliability Standards Development Plan	2012-2014 RSDP		9/12/11	9/26/11	Yes 9/26/11
38.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		8/15/11	9/28/11	Yes 9/28/11
39.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	BES Definition		8/26/11	10/10/11	Yes 10/10/11
40.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Technical Principles for Demonstrating BES Exceptions	Technical Principles for Demonstrating BES Exceptions		8/26/11	10/10/11	Yes 10/10/11
41.	N/A	New CAN Template, five DRAFT CANs for Industry review and CANs Status posted to NERC Compliance's Web site.	CANs		9/23/11	10/14/11	Yes 10/14/11
42.	RoP	Proposed Changes to NERC Rules of Procedure and All Appendices			9/2/11	10/17/11	
43.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Rules of procedure Modifications to Support BES Exception Requests	RoP Section 509, Section 1703 and Appendix 5C		9/13/11	10/27/11	Yes 10/27/11
44.	N/A	CAN-0010-- Definition of "Annual" and Implementation of Annual Requirements	CAN-0010 Definition of Annual		10/10/11	10/31/11	Yes 10/31/11

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45.	N/A	CAN-0011--PRC-005-1 R2: New Equipment	CAN-0011 PRC-005-1 R2		10/10/11	10/31/11	Yes 10/31/11
46.	N/A	CAN-0012--Completion of Periodic Activity Requirements During Implementation Plan	CAN-0012 Completion of Periodic Activity Requirements		10/10/11	10/31/11	Yes 10/31/11
47	N/A	CAN-0013--PRC-023 R1 and R2 Effective Dates for Switch-on-to-Fault Schemes	CAN-0013 PRC-023 R1 and R2		10/10/11	10/31/11	
48.	N/A	CAN-0015--Unavailability of NERC Software Tools	CAN-0015 NERC Tools		10/10/11	10/31/11	Yes 10/31/11
49.	N/A	CAN-0022--VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode	CAN-0022 VAR-002-1.1b R1 and R3		10/10/11	10/31/11	
50.	N/A	CAN-0024--CIP-002 R3 Routable Protocols and Data Diode Devices	CAN-0024 CIP-002, R3		10/10/11	10/31/11	Yes 10/31/11
51.	N/A	CAN-0026--TOP-006 R3 Protection Relays	CAN-0026 TOP-006, R3		10/10/11	10/31/11	Yes 10/31/11
52.	N/A	CAN-0028--TOP-006-1 R1.2 Reporting Responsibilities	CAN-0028 TOP-006-1, R1.2		10/10/11	10/31/11	
53.	N/A	CAN-0020--TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages	CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002		10/19/11	11/9/11	
54.	N/A	CAN-0030--Attestations	CAN-0030		10/19/11	11/9/11	
55.	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	MOD-028, R3.1		10/3/11	11/16/11	Yes 11/16/11
56.	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Interpretation of COM-002-2, R2		10/4/11	11/18/11	Yes 11/18/11

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57.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		10/5/11	11/18/11	Yes 11/18/11
58.	N/A	Draft Directive Regarding Generator Transmission Leads	Draft Directive #2011 CAG-001		10/17/11	11/18/11	Yes 11/18/11
59.	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 R1.1 by Progress Energy	Interpretation of CIP-006-1, R1.1		10/12/11	11/21/11	Yes 11/21/11
60.	N/A	CAN-0040 - BAL-003 Frequency Bias Calculation			11/2/11	11/23/11	
61.	N/A	CAN-0043 - PRC-005 Protection System Maintenance and Testing Evidence	PRC-005 Evidence		11/2/11	11/23/11	Yes 11/22/11
62.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1			12/8/11	Yes 12/8/11
63.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2			12/12/11	Yes 12/12/11
64.	N/A	Draft CAN-0027: TOP-003 R2 Coordination of Scheduled Outages	CAN-0027 TOP-003, R2		11/22/11	12/14/11	
65.	NERC RoP	Proposed Changes to the NERC Rules of Procedure and Associated Appendices			11/7/11	12/22/11	
66.	NERC RoP	Notice of Revisions to Proposed New Sections 1.1.24 and 5.11 of Appendix 4C of the NERC Rules of Procedure, as Originally Posted for Comment on November 7, 2011			11/22/11	12/22/11	
67.	Regional Standard	Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		11/22/11	12/22/11	

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68.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 (Version 5 CIP Standards)	Version 5 CIP Standards		11/7/11	1/6/12	Yes 1/6/12
69.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2	TOP-001-2 TOP-002-3 TOP-003-2		12/14/11	1/12/12	Yes 1/12/12
70.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition, Phase 2		1/4/12	2/3/12	Yes 2/3/12
71.	N/A	Order 754 - Request for Data or Information	Data Request		12/22/11	2/6/12	Yes 2/6/12
72.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001 COM-002 IRO-001-3		1/9/12	2/9/12	Yes 2/8/12
73.	WECC Regional Standard	Regional Reliability Standard BAL-004-WECC-02 - Automatic Time Error Correction	BAL-004-WECC-02		1/23/12	3/9/12	
74.	WECC Regional Standard	Regional Reliability Standard BAL-001-0.1a - Real Power Balancing Control Performance - WECC Variance	BAL-001-0.1a		1/23/12	3/9/12	
75.	N/A	NERC Functional Model Demand Response Functions and Entities	NERC Functional Model		2/13/12	3/14/12	
76.	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 for WECC	Interpretation of CIP-004-1		2/8/12	3/23/12	Yes 3/23/12
77.	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Interpretation of CIP-002-1, R3		2/8/12	3/23/12	Yes 3/23/12

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78.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Interpretation of VAR -002		2/8/12	3/23/12	Yes 3/23/12
79.	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing - PRC-005	PRC-005-2		2/28/12	3/28/12	Yes 3/28/12
80.	Project 2007-09	Project 2007-09 Generator Verification - MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		2/29/12	3/29/12	Yes 3/29/12
81.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - FAC-003-X, FAC-003-3	FAC-003-X FAC-003-3		3/9/12	4/9/12	Yes 4/9/12
82.	Project 2007-09	Project 2007-09 Generator Verification - MOD-025-2, MOD-027-1, and PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		2/29/12	4/16/12	Yes 4/16/12
83.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - PRC-005-1.1a	PRC-005-1.1a		3/2/12	4/16/12	Yes 4/16/12
84.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations	TOP-001 through TOP-008 and PER-001		3/22/12	4/20/12	Yes 4/20/12
85.	Project 2012-INT-02	Request for Interpretation - Project 2012-INT-02 TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		4/24/12	5/4/12	
86.	Project 2008-06	Project 2008-06 - Cyber Security Order 706 Version 5 CIP	CIP-002 and CIP-003 - Comment Form A		4/12/12	5/21/12	Yes 5/20/12
			CIP-004 thru CIP-007 - Comment Form B		4/12/12	5/21/12	Yes 5/20/12
			CIP-008 thru CIP-011 - Comment Form C		4/12/12	5/21/12	Yes 5/20/12
			Definitions and Implementation Plan - Comment Form D		4/12/12	5/21/12	Yes 5/20/12
87.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		4/25/12	5/24/12	Yes 5/24/12

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88.	Project 2007-12	Project 2007-12 Frequency Response Technical Conferences			5/30/12	6/15/12	
89.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003		5/7/12	6/20/12	Yes 6/20/12
90.	N/A	Adequate Level of Reliability Revised Definition and Associated Documents	Adequate Level of Reliability (ALR)		4/25/12	6/25/12	Yes 6/25/12
91.	N/A	Order 754 - Request for Data or Information	Data Request		5/11/12	6/25/12	Yes 6/25/12
92.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Interpretation of VAR -002		5/22/12	6/27/12	Yes 6/27/12
93.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		5/29/12	6/27/12	Yes 6/27/12
94.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserve	BAL-001-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-002-2		6/4/12	7/3/12	Yes 7/3/12
			BAL-012-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-013-1		6/4/12	7/3/12	Yes 7/3/12
95.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		5/21/12	7/5/12	Yes 7/5/12
96.	N/A	Cost Effective Analysis Process (CEAP) for NERC ERO Standards	CEAP		5/7/12	7/6/12	Yes 7/6/12
97.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001, COM-002 and IRO-001-3		6/7/12	7/6/12	Yes 7/6/12
98.	Project 2006-02	Project 2006-02 – Assess Transmission Future Needs and Develop Transmission Plans	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		6/19/12	7/9/12	Yes 7/9/12

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99.	N/A	Standard Processes Manual Revisions to Implement SPIG Recommendations	SPIG Reco		6/20/12	7/19/12	Yes 7/19/12
100.	Project 2012-INT-02	Project 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for System Protection and Control Subcommittee	- Interpretation of TPL-003-0a and TPL-004-0		6/20/12	7/20/12	Yes 7/19/12
101.	Project 2012-INT-05	Interpretation of 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		6/27/12	7/27/12	Yes 7/27/12
102.	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision to Address Interpretation of VAR-002 for Constellation	Rapid Revision to VAR-002		7/18/12	7/27/12	Yes 7/26/12
103.	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Rapid Revision of TOP-006		6/14/12	7/30/12	Yes 7/27/12
104.	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Glossary of Terms		6/19/12	8/2/12	Yes 8/2/12
105.	N/A	Reliability Guideline: System Operator Verbal Communications – Current Industry Practices	System Operator Verbal Communications		6/26/12	8/10/12	Yes 8/9/12
106.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		7/27/12	8/27/12	Yes 8/27/12
107.	Project 2010-11	Project 2010-11 - TPL Table 1 Order TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		7/31/12	8/29/12	Yes 8/29/12
108.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs			7/31/12	8/30/12	
109.	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group			7/25/12	9/4/12	

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110.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		8/3/12	9/4/12	Yes 9/4/12
111.	Project 2010-05.1	Project 2010-05.1 - Protection Systems: Phase 1 (Misoperations)			7/25/12	9/7/12	Yes 9/7/12
112.	N/A	Definition of Adequate Level of Reliability	Adequate Level of Reliability (ALR)		8/15/12	9/13/12	Yes 9/13/12
113.	N/A	2013-2015 Reliability Standards Development Plan	2013-2015 RSDP		8/17/12	9/18/12	Yes 9/18/12
114.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols	COM-003-1		8/22/12	9/20/12	Yes 9/20/12
115.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		8/29/12	9/27/12	
116.	SPP Regional Standard	Regional Reliability Standard PRC-006-SPP-01 Automatic Underfrequency Load Shedding	PRC-006-SPP-01		8/15/12	9/28/12	
117.	Project 2008-06 Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		9/11/12	10/10/12	Yes 10/10/12
			RSAW		9/11/12	10/10/12	Yes 10/10/12
118.	MRO SPM	Regional Reliability Standards - MRO Standards Process Manual			8/28/12	10/11/12	
119.	N/A	Standard Process Manual Revisions to Implement SPIG Recommendations	SPIG Reco		8/29/12	10/12/12	Yes 10/10/12
120.		Revisions to Outstanding VRFs and VSLs			9/5/12	10/19/12	
121.	Project 2013-01	Project 2013-01 - Cold Weather Preparedness			9/25/12	10/24/12	
122.	Project 2007-09	Project 2007-09 - Generator Verification			9/28/12	10/29/12	
123.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System			10/4/12	11/5/12	
124.	2007-12	Project 2007-12 - Frequency Response			10/5/12	11/7/12	

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125.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		10/26/12	11/7/12	
126.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025		10/5/12	11/7/12	
127.	N/A	IRO-006-WECC-2			10/3/12	11/16/12	
128.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B			10/5/12	11/19/12	
129.	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		10/22/12	12/5/12	Yes 12/5/12
130.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		10/25/12	12/10/12	Yes 12/10/12
131.	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	- Interpretation of CIP-003-3		11/9/12	12/10/12	Yes 12/10/12
132.	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	- Interpretation of CIP-007-3		11/9/12	12/10/12	Yes 12/10/12
133.	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols - RSAW	COM-003-1		11/14/12	12/13/12	Yes 12/13/12
			COM-003-1 RSAW		11/14/12	12/13/12	Yes 12/13/12
134.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		11/16/12	12/17/12	Yes 12/17/12
135.	Project 2012-INT-05	Project 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		11/6/12	12/20/12	Yes 12/20/12
136.	N/A	Standard Processes Manual to Implement SPIG Revisions	SPIG Reco		11/21/12	12/20/12	Yes 12/20/12
137.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		12/10/12	1/11/13	Yes 1/11/13
138.	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	PRC-024-1		12/12/12	1/11/13	Yes 1/11/13

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139.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-012-1	BAL-012-1		11/30/12	1/14/13	Yes 1/14/13
140.	N/A	Reliability Guideline--Draft Generating Unit Winter Weather Readiness - Current Industry Practices			12/20/12	2/4/13	Yes 2/4/13
141.	Project 2010-05-1	Project 2010-05-1 Protection System Misoperations					Yes 2/20/13
142.	Project 2007-09	Project 2007-09 Generator Verification - PRC-024-1	PRC-024-1	Formal	1/25/13	2/25/13	Yes 2/25/13
143.	N/A	Rapid Revision Procedure		Informal	2/25/13	3/6/13	Yes 3/6/13
144.	Project 2010-13-2	Project 2010-13-2 - Phase 2 of Relay Loadability - Generation - PRC-025-1	PRC-025-1	Formal	1/25/13	3/11/13	Yes 3/11/13
			Supplemental SAR	Informal	1/25/13	3/11/13	Yes 3/11/13
			Cost Effectiveness	CEAP Pilot	1/25/13	3/11/13	Yes 3/11/13
			RSAW	Feedback	1/25/13	3/11/13	Yes 3/11/13
145.	Project 2012-INT-04	Interpretation 2012-INT-04 - Interpretation of CIP-007 for ITC	Interpretation of CIP-007	Formal	2/6/13	3/22/13	Yes 3/22/13
146.	Project 2012-INT-06	Interpretation 2012-INT-06 - Interpretation of CIP-003 for Consumers Energy	Interpretation of CIP-003	Formal	2/6/13	3/22/13	Yes 3/22/13
147.	Project 2012-08-1	Project 2012-08-1 - Phase 1 of Glossary Updates--Statutory Definitions	Glossary of Terms	Formal	2/21/13	3/22/13	Yes 3/22/13
148.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003-1	COM-003-1	Formal	3/7/13	4/5/13	Yes 4/5/13
			RSAW	Feedback	3/7/13	4/5/13	Yes 4/5/13
149.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-001-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-002-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-013-1	Formal	3/12/13	4/25/13	Yes 4/25/13

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150.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)	Draft SAR	Informal	4/5/13	5/6/13	Yes 5/6/13
			PRC-005-3	Formal	4/5/13	5/6/13	Yes 5/613
151.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation	PRC-023-3 PRC-025-1	Formal	4/25/13	5/24/13	Yes 5/24/13
152.	Project 2007-11	Project 2007-11 - Disturbance Monitoring — PRC-002 and PRC-018	SAR	Informal	5/03/13	6/03/13	Yes 6/3/13
153.	Project 2007-11	Project 2007-11 - Disturbance Monitoring PRC-002 and PRC-018	Request for Information	Informal	6/05/13	7/05/13	
154.	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	PRC-001 and PRC-027		6/04/13	7/03/13	Yes 7/03/13
155.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition		5/29/13	7/12/13	Yes 7/12/13
156.	TRE Regional Standard	Regional Reliability Standard - BAL-001-TRE-01	BAL-001-TRE-01		5/31/13	7/15/13	
157.	N/A	NPCC Regional Standards Process Manual	NPCC RSPM		6/06/13	7/22/13	
158.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003-1		6/20/13	7/19/13	Yes 7/19/13
159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13

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163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13
169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	Yes 9/4/13
170	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System – Phase 2	BES Definition Phase 2	Formal	8/6/13	9/4/13	Yes 9/4/13
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	Yes 9/9/13
172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	Yes 9/13/13
173	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-001-1 FAC-002-1	5-year review	8/1/13	9/16/13	Yes 9/16/13
174	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-003-3 FAC-008-3 FAC-010-2.1 FAC-011-2 FAC-013-2 FAC-014-2	5-year review	8/1/13	9/16/13	Yes 9/16/13

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175	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	BAL-002-2	Formal	8/2/13	9/16/13	Yes 9/16/13
176	Project 2009-03	Project 2009-03 — Five-Year Review of Emergency Operations EOP-001, EOP-002, EOP-003, and IRO-001	EOP-001-2.1b EOP-002-3.1 EOP-003-2	5-year review	8/6/13	9/19/13	Yes 9/19/13
177	Project 2012-09	Project 2012-09 IRO Five-Year Review	IRO-003-2 IRO-004-2 IRO-005-4 IRO-006-5 IRO-006-East IRO-008-1 IRO-009-1 IRO-010-1a	5-year review	8/7/13	9/20/13	Yes 9/20/13
178	Project 2008-02	Project 2008-02 Undervoltage Load Shedding	Revised SAR	Informal	9/10/13	10/9/13	Yes 10/9/13
179	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	9/4/13	10/18/13	Yes 10/18/13
180	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition	Formal	9/27/13	10/28/13	Yes 10/28/13
181	Project 2007-02	Project 2007-02 Operating Personnel Communications Protocols	COM-002-4	Formal	10/21/13	11/7/13	Yes 11/4/13
182	Project 2010-01	Project 2010-01 Training	PER-005-2	Formal	9/27/13	11/12/13	Yes 11/12/13
183	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	Various INT Standards	Formal	9/30/13	11/13/13	Yes 11/13/13
184	Project 2012-05	Project 2012-05 ATC Revisions (MOD A)	MOD-001-2	Formal	10/4/13	11/20/13	Yes 11/18/13
185	Project 2010-03	Project 2010-03 Modeling Data (MOD B)	MOD-032-1, MOD-033-1	Formal	10/07/13	11/20/13	
186	Project 2010-04	Project 2010-04 Demand Data (MOD C)	MOD-031-1	Formal	10/09/13	11/22/13	Yes 11/22/13
187	Project 2013-04	Project 2013-04 Voltage and Reactive Control	VAR-001-4, VAR-002-3	Formal	10/11/13	11/25/13	Yes 11/25/13

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188	Project 2009-03	Project 2009-03 Emergency Operations	SAR	Informal	11/06/13	12/05/13	Yes 12/5/13
189	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-002-2	Formal	10/28/13	12/11/13	Yes 12/11/13
190	Project 2007-11	Project 2007-11 - Disturbance Monitoring	PRC-002-2	Formal	11/01/13	12/16/13	Yes 12/16/13
191	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-027	Formal	11/04/13	12/18/13	Yes 12/18/13
192	Project 2014-01	Project 2014-01 - Standards Applicability for Dispersed Generation Resources	SAR	Formal	11/20/13	12/19/13	Yes 12/19/13
193	Project 2010-01	Project 2010-01 Training - PER-005-2	PER-005-2	Formal	12/4/13	1/22/14	Yes 1/17/14
194	Project 2010-03	Project 2010-03 Modeling Date - MOD B	MOD-033-1	Formal	12/6/13	1/22/14	Yes 1/21/14
195	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	INT-004-3 INT-010-2	Formal	1/10/14	1/24/14	Yes 1/22/14
196	Project 2007-02	Project 2007-02 Operating Personnel	COM-002-4	Formal	1/22/14	1/31/14	Yes 1/31/14
197	Project 2014-02	Project 2014-02 Standard Authorization Request – Cyber Security Standards	CIP SAR	Informal	1/17/14	2/18/14	Yes 2/18/14
198	2014 Work Plan	2014 Work Plan for NERC Reliability Standards Development	2014 Work plan			2/21/13	Yes 2/21/14
199	Project 2010-17	Project 2010-17 Definition of Bulk Electric System - Phase 2	BES	Informal	1/29/14	2/27/14	Yes 2/27/14
200	Project 2010-05.1	Project 2010-05.1 Protection System: Phase 1 (Misoperations) - PRC-004-3	PRC-004-3	Formal	1/17/14	3/11/14	Yes 3/2/14

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201	Project 2012-13	Project 2012-13 NUC-Nuclear Plant Interface Coordination Standard Authorization Request	NUC-001-2.1 SAR	Informal	2/12/14	3/13/14	Yes 3/13/14
202	Project 2010-05.2	Project 2010-05.2 Special Protection Systems (Phase 2 of Protection Systems) - SAR	SAR	Informal	2/18/14	3/19/14	Yes 3/19/14
203	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	SAR	Formal	02/21/14	03/24/14	Yes 3/24/14
204	Project 2014-03	Technical Conferences on Revisions to TOP/IRO Reliability Standards	Technical Conference Topics	Informal	03/11/14	03/24/14	
205	Project 2014-04	Project 2014-04 - Physical Security	SAR	Informal	03/21/14	03/28/14	Yes 3/28/14
206	Project 2010-14.2	Project 2010-14.2 - Periodic Review of BAL Standards	Reco to Revise BAL-005 and BAL-006	Formal	02/21/14	04/07/14	
207	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Informal	03/11/14	04/09/14	Yes 4/9/14
208	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	02/25/14	04/10/14	Yes 4/10/14
209	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-002-3	Formal	02/27/14	04/14/14	Yes 4/14/14
210	Project 2008-02	Project 2008-02 - Undervoltage Load Shedding - PRC-010, PRC-020, PRC-021 and PRC-022	PRC-010-1	Informal	03/17/14	04/16/14	Yes 4/16/14
211	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	CIP-014-1	Formal	04/10/14	04/24/14	Yes 4/24/14
212	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Informal	03/28/14	04/28/14	Yes 4/28/14

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213	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	04/17/14	05/05/14	Yes 5/5/14
214	Project 2010-02	Project 2010-02 – Connecting New Facilities to the Grid	FAC-001-1 FAC-002-1	Formal	04/01/14	05/15/14	Yes 5/15/14
215	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Informal	04/22/14	05/21/14	Yes 5/21/14
216	Project 2012-13	Project 2012-13 Nuclear Plant Interface Coordination	NUC-001-3	Formal	04/08/14	05/22/14	Yes 5/22/14
217	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays)	PRC-005-X	Formal	04/17/14	06/03/14	Yes 6/3/14
218	Project 2010-13.3	Project 2010-13.3 Relay Loadability: Stable Power Swings	PRC-026-1	Formal	04/25/14	06/09/14	Yes 6/9/14
219	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	05/09/14	06/25/14	Yes 6/25/14
221	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Informal	05/23/14	06/23/14	Yes 6/23/14
222	Project 2010-05-1	Project 2010-05-1 Protection System – Phase 1 – Misoperations	PRC-004	Formal	05/16/14	07/09/14	Yes 7/9/14
223	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	05/19/14	07/02/14	Yes 7/2/14
224	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-002 to CIP-011	Formal	06/02/14	07/17/14	Yes 7/16/14

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		– Cyber Security Standards					
225	Project 2015-2017	Project 2015-2017 Reliability Standard Development Plan		Informal		7/21/14	Yes 7/21/14
226	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Formal	7/16/14	7/25/14	Yes 7/25/14
227	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	06/12/14	7/29/14	Yes 7/29/14
228	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	06/13/14	07/30/14	Yes 7/30/14
229	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Formal	06/23/14	08/8/14	Yes 8/6/14
230	Project 2010-14-2	Project 2010-14-2 Balancing Authority Reliability-based Control Standard Authorization Request for BAL-005 and BAL-006	BAL-005 BAL-006	Informal	07/16/14	08/14/14	Yes 8/12/14
231	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Formal	07/2/14	08/15/14	Yes 8/13/14
232	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-004-2.1a(X) PRC-004-3(X)	Formal	07/10/14	08/26/14	Yes 8/25/14
233	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays) – PRC-005-X	PRC-005-X	Formal	07/30/14	09/12/14	Yes 9/12/14
234	Project 2014-03	Project 2014-03 Revisions to TOP-	TOP-001-3 TOP-002-4	Formal	08/6/14	09/19/14	Yes 9/22/14

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		IRO Reliability Standards	TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1				
235	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	08/19/14	10/03/14	Yes 10/2/14
236	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	09/26/14	10/06/14	Yes 10/6/14
237	Project 2008-02	Project 2008-02: Underfrequency Load Shedding (UFLS)	PRC-006-2	Formal	08/21/14	10/08/14	Yes 10/7/14
238	Project 2013-03	Project 2013-03: Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	08/27/14	10/10/14	Yes 10/10/14
239	NERC Rules of Procedure	NERC Rules of Procedure	NERC Rules of Procedure	Formal	08/26/14	10/10/14	Yes 10/14/14
240	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems Phase 2 of Protection Systems	RAS Definition	Formal	08/29/14	10/14/14	Yes 10/14/14
241	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	VAR-002-2b(X) VAR-002-4	Formal	08/27/14	10/16/14	Yes 10/16/14
242	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-003-6 CIP-010-2 CIP-003-X CIP-004-X CIP-007-X CIP-010-X CIP-011-X	Formal	09/03/14	10/17/14	Yes 10/17/14
243	Project 2009-03	Project 2009-03 Emergency Operations	EOP-011-1	Formal	09/05/14	10/20/14	Yes 10/20/14
244	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Preliminary Draft 5)	PRC-027-1	Informal	10/01/14	10/21/14	Yes 10/21/14

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245	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	09/05/14	10/21/14	Yes 10/21/14
246	Project 2014-01	Project 2014-01 Applicability for Dispersed Generation	PRC-004-2.1a(X) PRC-004-4	Formal	09/05/14	10/22/14	Yes 10/22/14
247	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	10/10/14	11/10/14	Yes 11/10/14
248	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1	TPL-007-1	Formal	10/28/14	11/21/14	Yes 11/24/14
249	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	11/04/14	11/24/14	Yes 11/25/14
250	Project 2014-01	Project 2014-01 – Standards Applicability for Dispersed Generation Resources	PRC-001-1.1 PRC-019-2 PRC-024-1	Formal	11/05/14	12/23/14	Yes 12/22/14
251	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	12/29/14	1/7/15	Yes 1/6/15
252	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-003-7 CIP-004-7 CIP-007-7 CIP-010-3 CIP-011-3 CIP-003-7 CIP-010-3 Implementation Plan	Formal	12/30/14	1/9/15	Yes 1/9/15
253	Project 2014-04	Project 2014-04 Physical Security SAR	SAR	Informal	12/15/14	1/13/15	Yes 1/12/15
254	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	White Paper Appendix A Appendix B	Informal	12/22/14	1/20/15	Yes 1/20/15
255	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed	PRC-005-5	Informal	12/22/14	1/20/15	Yes 1/22/15

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		Generation Resources					
257	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	1/29/15	3/18/15	Yes 3/16/15
258	Reliability Guideline	Reliability Guideline: Loss of Real-Time Reliability Tools Capability/Loss of Equipment Significantly Affecting ICCP Data		Formal	2/19/15	4/6/15	Yes 4/6/15
259	Project 2008-02.2	Project 2008-02.2 Phase 2 UVLS: Misoperation	PRC-010-2	Formal	2/20/15	4/7/15	Yes 4/7/15
260	Project 2014-04	Project 2014-04 Physical Security	CIP-014-2	Formal	2/20/15	4/9/15	Yes 4/9/15
261	Project 2015-04	Project 2015-04 Alignment of Terms	SAR	Formal	2/24/15	4/13/15	Yes 4/13/15
262	Project 2007-17.4	Project 2007-17.4 PRC-005 Order No. 803 Directives	SAR	Informal	3/12/15	4/10/15	Yes 4/13/15
263	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	SAR	Informal	3/16/15	4//15/15	Yes 4/15/15
264	Project 2010-14.2.2	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	SAR	Informal	3/17/15	4//15/15	Yes 4/15/15
265	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-008-1	Informal	3/27/15	5/11/15	Yes 5/11/15
266	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-006-2	Informal	3/27/15	5/11/15	Yes 5/11/15
267	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-005-2	Informal	3/27/15	5/11/15	Yes 5/11/15
268	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-004-2	Informal	3/27/15	5/11/15	Yes 5/11/15

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269	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Draft 5)	PRC-027-1	Formal	4/1/15	5/15/15	Yes 5/15/15
270	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	SAR	Informal	4/16/15	5/19/15	Yes 5/19/15
271	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems – RAS	PRC-012-2	Informal	4/30/15	5/20/15	Yes 5/20/15
272	Project 2015-03	Project 2015-03 Periodic Review of System Operating Limit Standards	FAC-010-3 FAC-011-3 FAC-014-2	Formal	5/4/15	6/17/15	Yes 6/17/15
273	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	IRO-006-East-2 IRO-009-2	Formal	5/21/15	7/8/15	Yes 7/8/15
274	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	PRC-005-3	Formal	6/11/15	7/10/15	Yes 7/10/15
275	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generations Resources	PRC-004-2.1 PRC-005-2 PRC-005-3	Informal	6/12/15	7/13/15	Yes 7/13/15
276	Project 2015-07	Project 2015-07 Internal Communications Capabilities	COM-001-2	Informal	6/11/15	7/15/15	Yes 7/15/15
277	Project 2015-04	Alignment of Terms	Glossary Terms	Formal	6/12/15	7/23/15	Yes 7/23/15
278	Project 2009-02	Real-time Monitoring and Analysis Capabilities	SAR	Formal	7/16/15	8/17/15	Yes 8/17/15
279	NERC 2016-2018	Reliability Standards Development Plan	Development Plan	Formal	7/16/15	8/17/15	Yes 8/17/15
280	Project 2015-08	Emergency Operations	EOP-004-2 EOP-005-2 EOP-006-2 EOP-008-1	Informal	7/21/15	8/19/15	Yes 8/19/15
281	Project 2010-14.1	Phase 1 of Balancing Authority Reliability-based Controls	BAL-002-2	Formal	7/7/15	8/20/15	Yes 8/20/15
282	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based	BAL-004-0	Survey	8/12/15	8/25/15	Yes 8/25/15

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		Controls: Time Error Correction					
283	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	7/29/15	9/11/15	Yes 9/11/15
284	Project 2007-06	System Protection Coordination	PRC-027-1	Formal	7/29/15	9/11/15	Yes 9/11/15
285	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 BAL-006-3	Formal	7/30/15	9/14/15	Yes 9/14/15
286	Project 2007-17.4	PRC-005 FERC Order No. 803 Directive	PRC-005-6	Formal	7/30/15	9/16/15	Yes 9/16/15
287	Project 2010-04.1	MOD-031 FERC Order No. 804 Directives	MOD-031-2	Formal	7/31/15	9/18/15	Yes 9/18/15
288	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010-3 FAC-011-3 FAC-014-2	Informal	8/20/15	9/21/15	Yes 9/21/15
289	Project 2010-07.1	Vegetation Management	FAC-003-3	Informal	8/24/15	9/28/15	Yes 9/28/15
290	Project 2010-05.3	Phase 3 of Protection Systems: Remedial Action Schemes	PRC-012-2	Formal	8/20/15	10/5/15	Yes 10/5/15
291	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	9/24/15	11/9/15	Yes 11/9/15
292	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls	BAL-004-0	Formal	9/24/15	11/12/15	Yes 11/12/15
293	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	9/25/15	11/16/15	Yes 11/16/15
294	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	10/6/15	11/19/15	Yes 11/19/15
295	Project 2010-07.1	Vegetation Management	FAC-003-3	Formal	10/30/15	12/16/15	Yes 12/16/15
296	Project 2015-10	Single Points of Failure SAR	TPL-001	Informal	11/12/15	12/17/15	Yes 12/17/15
297	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	11/25/15	1/8/16	Yes 1/8/16
298	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 FAC-001-3 BAL-006-2	Formal	12/31/15	1/11/16	Yes 1/11/16
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

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300	Project 2016-01	Modifications to TOP and IRO Standards	SAR	Informal	1/22/16	2/22/16	Yes 2/22/16
301	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	2/3/16	3/18/16	Yes 3/18/16
302	Project 2016-02	Modifications to CIP Standards	SAR	Informal	3/23/16	4/21/16	Yes 4/21/16
303	Project 2007-06.2	Phase 2 of System Protection Coordination	PER-006-1 & Two Definitions	Formal	3/10/16	4/25/16	Yes 4/25/16
304	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	3/23/16	5/9/16	Yes 5/6/16
305	CEP	Cost Effectiveness Pilot	TPL-001-4	Informal	4/27/16	5/26/16	Yes 5/26/16
306	Project 2013-03	Geomagnetic Disturbance Mitigation Revised White Papers	SAR	Informal	5/12/16	6/13/16	Yes 6/13/16
307	Project 2015-10	Single Points of Failure	SAR	Informal	5/26/16	6/24/16	Yes 6/24/16
308	Project 2016-02	Modifications to CIP Standards	SAR	Informal	6/1/16	6/30/16	Yes 6/30/16
309	Draft 2017-2019	Reliability Standards Development Plan	RSDP	Informal	6/20/16	7/19/16	Yes 7/19/16
310	EPR	Enhanced Periodic Review Standing Review Team	Standards Grading	Informal	6/30/16	8/1/16	Yes 8/1/16
311	Project 2016-01	Modifications to TOP and IRO Standards	IRO-002-5 TOP-001-4	Formal	6/20/16	8/3/16	Yes 8/3/16
312	Project 2015-09	Establish and Communicate System Operating Limits	FAC-014-3	Formal	7/14/16	8/12/16	Yes 8/12/16
313	Project 2015-09	Establish and Communicate System Operating Limits	FAC-011-4	Formal	7/14/16	8/12/16	Yes 8/12/16
314	Project 2015-08	Emergency Operations	EOP-005-3 EOP-006-3 EOP-008-2	Formal	6/30/16	8/15/16	Yes 8/15/16
315	Project 2016-02	Modifications to CIP Standards	CIP-003-7	Formal	7/21/16	9/6/16	Yes 9/6/16
316	FMAG	Functional Model Advisory Group	Reliability Functional Model and Technical Document	Informal	7/21/16	9/7/16	Yes 9/7/16
317	Project 2015-08	Emergency Operations	EOP-004-4	Formal	7/25/16	9/8/16	Yes 9/8/16
318	Project 2015-INT-01	Interpretation of CIP-002-5.1 for Energy Sector	CIP-002-5.1	Formal	7/27/16	9/12/16	Yes 9/12/16

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		Security Consortium (EnergySec)					
319	Project 2016-01	Modifications to TOP and IRO Standards SAR	TOP-001-3 IRO-002-4	Formal	8/31/16	10/17/16	Yes 10/14/16
320	Project 2016-04	Modifications to PRC-025-1 SAR	PRC-025-1	Formal	9/16/16	10/18/16	Yes 10/18/16
321	Project 2016-03	Cyber Security Supply Chain Management	SAR	Informal	10/20/16	11/18/16	Yes 11/18/16
322	Project 2016-02	Modifications of CIP Standards	CIP-003-TCA	Informal	11/1/16	11/18/16	Yes 11/18/16
323	Project 2016-02	Modifications of CIP Standards	CIP-003-7	Formal	11/23/16	12/5/16	Yes 12/5/16
324	Project 2015-08	Emergency Operations	EOP-005-3 EOP-006-3	Formal	10/26/16	12/9/16	Yes 12/9/16
325	Project 2015-08	Emergency Operations	EOP-004-4	Formal	11/18/16	1/6/17	Yes 1/6/17
326	Project 2013-03	Geomagnetic Disturbance Mitigation	SAR	Informal	12/16/16	1/20/17	Yes 1/20/17
327	Project 2016-02	Modifications of CIP Standards	CIP-003-7(i)	Formal	12/12/16	1/25/17	Yes 1/25/17
328	Project 2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training and Qualifications Standard (PER)	PER-001-0.2 PER-003-1 PER-004-2	Formal	1/10/17	2/23/17	Yes 2/23/17
329	Project 2016-03	Cyber Security Supply Chain Risk Management	CIP-013-1	Formal	1/19/17	3/6/17	Yes 3/6/17
330	Project 2016-04	Modifications to PRC-025-1	SAR	Informal	3/20/17	4/3/17	Yes 4/3/17
331	Project 2016-02	Modifications to CIP Standard	Virtualization	Informal	3/14/17	4/11/17	Yes 4/11/17
332	Project 2016-02	Modifications to CIP Standard	TOCC	Informal	3/14/17	4/11/17	Yes 4/11/17
333	Project 2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive (VAR) Standards	VAR-001-4.1	Formal	2/28/17	4/13/17	Yes 4/13/17
334	Project 2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive (VAR) Standards	VAR-002-4	Formal	2/28/17	4/13/17	Yes 4/13/17
335	SPM	Revisions to the NERC Standard Processes Manual	SPM	Formal	3/20/17	5/3/17	Yes 5/3/17
336	Project 2015-10	Single Points of Failure	TPL-001-5	Informal	4/25/17	5/24/17	Yes 5/24/17

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337	Project 2016-03	Cyber Security Supply Chain Risk Management	CIP-005-6 CIP-010-3 CIP-013-1	Formal	5/2/17	6/15/17	Yes 6/15/17
338	Project 2017-01	Modifications to BAL-003-1.1 SAR	BAL-003-1.1	Formal	6/19/17	7/18/17	Yes 7/18/17
339	Project 2017-06	Modifications to BAL-002-2 SAR	BAL-002-2	Informal	6/20/17	7/20/17	Yes 7/20/17
340	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications Standards	PER-003-1 PER-004-2	Informal	6/21/17	7/24/17	Yes 7/24/17
341	2018-2010	Reliability Standards Development Plan		Formal	6/22/17	7/25/17	Yes 7/26/17
342	Standards Grading	Periodic Review Standing Review Team	Standards Grading	Informal	6/19/17	8/2/17	Yes 8/2/17
343	Project 2013-03	Geomagnetic Disturbance Mitigation	TPL-007-2	Formal	6/28/17	8/11/17	Yes 8/11/17
344	Project 2017-07	Alignment with Registration	Registration	Formal	8/1/17	8/30/17	Yes 8/30/17
345	Project 2017-07	Alignment with Registration	MOD-032-1 SAR	Formal	8/1/17	8/30/17	Yes 8/30/17
346	Reliability Guideline	Area Control Error Diversity Interchange Process	ACE Process	Formal	7/18/17	8/31/17	Yes 8/31/17
347	Project 2016-04	Modifications to PRC-025-1	PRC-025-2	Formal	7/25/17	9/7/17	Yes 9/7/17
348	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	7/27/17	9/11/17	Yes 9/11/17
349	Project 2016-02	Modifications to CIP Standard	Technical Rationale and Justification for CIP-012-1	Informal	8/14/17	9/12/17	Yes 9/12/17
350	Project 2016-02	Modifications to CIP Standard	Definition of Control Center	Informal	8/14/17	9/12/17	Yes 9/12/17
351	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	9/8/17	10/23/17	Yes 10/23/17
352	Project 2016-02	Modifications to CIP Standard	CIP-002-6	Formal	9/14/17	10/30/17	Yes 10/30/17
353	Project 2015-09	Establish and Communicate System Operating Limits	Proposed Definitions of System Operating Limit (SOL) and SOL Exceedance	Informal	9/29/17	10/30/17	Yes 10/30/17
354	Project 2016-02	Modifications to CIP Standard	Virtualization	Informal	10/6/17	11/2/17	Yes 11/2/17
355	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010 FAC-011 FAC-014	Formal	9/29/17	11/13/17	Yes 11/13/17
356	Project 2017-01	Modifications to BAL-003-1.1	SAR	Formal	11/2/17	12/1/17	Yes 12/1/17

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357	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	10/27/17	12/11/17	Yes 12/11/17
358	Project 2016-02	Modifications to CIP Standard	Technical Rationale/Justification	Informal	11/20/17	12/11/17	Yes 12/11/17
359	Project 2017-03	FAC-008-3 Periodic Review	FAC-008-3	Formal	10/30/17	12/13/17	Yes 12/13/17
360	Project 2016-04	Modifications to PRC-025-1	PRC-025-1	Formal	10/30/17	12/13/17	Yes 12/13/17
361	Project 2017-07	Alignment with Registration	SAR	Formal	12/11/17	1/9/18	Yes 1/9/18
362	Project 2017-05	NUC-001-3	NUC-001-3	Formal	12/15/17	1/29/18	Yes 1/29/18
363	Project 2017-04	INT Periodic Review	INT-004-3.1 INT-006-4 INT-009-2.1 INT-010-2.1	Formal	1/10/18	2/23/18	Yes 2/23/18
364	Project 2017-07	Standards Alignment with Registration	Multiple Standards	Formal	2/1/18	3/2/18	Yes 3/2/18
365	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications (PER) Standards	PER-003-1 PER-004-2	Formal	1/22/18	3/7/18	Yes 3/7/18
366	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	2/23/18	4/23/18	Yes 4/23/18
367	Project 2018-01	Canadian-specific Revisions to TPL-007-2 SAR	TPL-007-2 SAR	Formal	3/30/18	4/30/18	Yes 4/30/18
368	Project 2016-02	Modifications to CIP Standard	CIP-002-6	Formal	3/16/18	4/30/18	Yes 4/30/18
369	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	3/16/18	4/30/18	Yes 4/30/18
370	Project 2016-02	Modifications to CIP Standard	Control Center Definition and Implementation	Formal	3/16/18	4/30/18	Yes 4/30/18
371	Standards Grading	2018 Periodic Review Standing Review Team	Standard Grading	Informal	5/14/18	6/28/18	Yes 6/28/18
372	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	5/18/18	7/3/18	Yes 7/2/18
373	SER	Standard Efficiency Review	SAR	Informal	6/7/18	7/10/18	Yes 7/10/18
374	Project 2016-02	Modifications to CIP Standard	CIP-002-5.1a SAR	Informal	6/14/18	7/13/18	Yes 7/13/18
375	Project 2016-02	Modifications to CIP Standard	CIP-003-7 SAR Order 843	Informal	6/14/18	7/13/18	Yes 7/13/18
376	SPM	Standards Processes Manual	SPM	Formal	6/25/18	8/9/18	Yes 8/9/18
377	Project 2018-01	Canadian-specific Revisions to TPL-007-2	TPL-007-2	Informal	8/10/18	9/6/18	Yes 9/6/18

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378	Project 2018-02	Modifications to CIP-008 Cyber Security Incident Reporting SAR	CIP-008-5	Informal	8/10/18	9/10/18	Yes 9/10/18
379	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	7/30/18	9/14/18	Yes 9/14/18
380	Functional Model Advisory Group	Functional Model Advisory Group	Functional Model Advisory Group	Informal	8/3/18	9/19/18	Yes 9/17/18
381	Project 2017-01	Modifications to BAL-003-1.1	BAL-003-1.1	Informal	9/6/18	9/20/18	Yes 9/20/18
382	SER	Standard Efficiency Review	SAR	Formal	8/28/18	9/26/18	Yes 9/26/18
383	Project 2016-02	Modifications to CIP Standards	CIP-002-6	Formal	8/23/18	10/9/18	Yes 10/9/18
384	Project 2016-02	Modifications to CIP Standards	CIP-003-8	Formal	8/23/18	10/9/18	Yes 10/9/18
385	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010 FAC-011 FAC-014	Formal	8/24/18	10/17/18	Yes 10/17/18
386	Project 2018-02	Cyber Security – Incident Reporting and Response Planning	CIP-008-6	Formal	10/3/18	10/22/18	Yes 10/22/18
387	Project 2018-01	Canadian-specific Revisions to TPL-007-2	TPL-007-2	Formal	10/2/18	11/15/18	Yes 11/15/18
388	Project 2018-02	Cyber Security – Incident Reporting and Response Planning	CIP-008-6	Formal	11/15/18	11/29/18	Yes 11/29/18
389	Project 2016-02	Modifications to CIP Standards	Virtualization	Informal	11/2/18	12/18/18	Yes 12/18/18
390	Project 2017-01	Modifications to BAL-003-1.1	BAL-003-1.1	Formal	12/4/18	1/17/19	Yes 1/17/19
391	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Formal	12/19/18	1/18/19	Yes 1/18/19
392	Standard Efficiency Review	Standard Efficiency Review	SER Phase 2 Concepts Survey	Informal	2/22/19	3/22/19	Yes 3/22/19
393	Project 2019-01	Modifications to TPL-007-3	TPL-007-3	Informal	2/25/19	3/26/19	Yes 3/26/19
394	Project 2018-03	Standard Efficiency Review Retirements	FAC-008-4 INT-006-5 INT-009-3 IRO-002-6 PRC-004-6 TOP-001-5 VAR-001-6 FAC-013-2 INT-004-3.1	Formal	2/27/19	4/12/19	Yes 4/12/19

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			INT-010-2.1 MOD-001-1a MOD-004-1 MOD-008-1 MOD-020-0 MOD-028-2 MOD-029-2a MOD-030-3 MOD-001-2				
395	Project 2019-02	BES Cyber System Information Access Management	CIP-004-6	Formal	3/28/19	4/26/19	Yes 4/26/19
396	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Formal	4/17/19	5/31/19	Yes 5/31/19
397	Project 2016-02	Modifications to CIP Standards	Virtualization White Paper	Informal	5/30/19	6/28/19	Yes 6/28/19
398	Project 2016-02	Modifications to CIP Standards	CIP-002-6	Formal	6/3/19	7/17/19	Yes 7/17/19
399	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Informal	6/27/19	7/26/19	Yes 7/26/19
400	Project 2019-03	Cyber Security Supply Chain Risks	CIP-005-6 CIP-010-3 CIP-013-1	Informal	7/2/19	8/1/19	Yes 8/1/19
401	SER	CIP SER	CIP Standards	Formal	7/3/19	8/26/19	Yes 8/26/19
402	Project 2019-04	Modifications to PRC-005-6	PRC-005-6 SAR	Formal	7/30/19	8/28/19	Yes 8/28/19
403	Project 2019-05	Modifications to PER-003-2	PER-003-2	Informal	8/1/19	8/30/19	Yes 8/30/19
404	Project 2016-02	Modifications to CIP Standards	CIP-005	Informal	8/9/19	9/26/19	Yes 9/26/19
405	EMP	Electromagnetic Pulses Task Force Draft Strategic Recommendation	EMP	Informal	8/30/19	9/30/19	Yes 9/30/19
406	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Formal	9/20/19	11/4/19	Yes 11/4/19
407	Project 2019-06	Cold Weather SAR	SAR	Formal	10/4/19	11/5/19	Yes 11/5/19
408	Project 201707	Standards Alignment with Registration	FAC-002-3 IRO-010-3 MOD-031-3 MOD-033-2 NUC-001-4 PRC-006-4 TOP-003-4	Formal	10/29/19	12/12/19	Yes 12/12/19
409	Project 2016-02	Modifications to CIP Standards	CIP-002-6	Formal	11/1/19	12/16/19	Yes 12/16/19
410	Project	Technical Rationale for Reliability Standards	IRO-001-4 IRO-002-6 IRO-006-East-2 IRO-008-2 IRO-009-2	Informal	11/4/19	12/18/19	Yes 12/18/19

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
			IRO-010-2 IRO-014-3 IRO-017-1 IRO-018-1(i)				
411	Project 2019-02	BES Cyber System Information Access Management	CIP-004-6	Formal	12/20/19	2/3/20	Yes 2/3/20
412	Project 2019-03	Cyber Security Supply Chain Risks	CIP-005-6 CIP-010-3 CIP-013-1	Formal	1/27/20	3/11/20	Yes 3/11/20
413	Project 2019-06	Cold Weather SAR	SAR	Formal	2/19/20	3/19/20	Yes 3/19/20
414	Project	Technical Rationale for Reliability Standards	IRO-001-4 IRO-002-6 IRO-006-East-2 IRO-008-2 IRO-009-2 IRO-010-2 IRO-014-3 IRO-017-1 IRO-018-1(i)	Informal	4/10/20	4/20/20	Yes 4/20/20
415	Project 2020-01	Modifications to MOD-032-1	MOD-032-1	Informal	3/24/20	4/24/20	Yes 4/24/20
416	Project 2020-02	Transmission-connected Resources SAR	MOD-025 MOD-026 MOD-027 PRC-019 PRC-024	Informal	3/30/20	5/13/20	Yes 5/13/20
417	Project 2019-06	Cold Weather SAR	SAR	Informal	4/22/20	5/21/20	Yes 5/21/20
418	SER	Operational Data Exchange Simplification SAR	SAR	Survey	3/12/20	5/27/20	Yes 5/28/20
419	Project 2020-03	Supply Chain Low Impact Revisions	SAR	Informal	4/3/20	6/3/20	Yes 6/3/20
420	Project 2020-04	Modifications to CIP-012	SAR	Informal	4/8/20	6/11/20	Yes 6/11/20
421	Project 2019-03	Cyber Security Supply Chain Risks	CIP-005-6 CIP-010-3 CIP-013-1	Formal	5/7/20	6/22/20	Yes 6/22/20
422	Project 2019-04	Modifications to PRC-005-6	PRC-005-6	Formal	6/2/20	7/8/20	Yes 7/8/20
423	Project 2015-09	Establish and Communicate System Operating Limits	CIP-014-3 FAC-003-5 FAC-011-4 FAC-013-3 FAC-014-3 PRC-002-3 PRC-026-2 TOP-001-6 IRO-008-3	Formal	6/19/20	8/3/20	Yes 8/3/20
424	2021-2023	Reliability Standards Development Plan	Reliability Standards Development Plan	Informal	8/11/20	9/9/20	Yes 9/9/20

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425	Project 2019-03	Cyber Security Supply Chain Risks	CIP-005-7 CIP-010-4 CIP-013-2	Formal	7/28/20	9/10/20	Yes 9/10/20
426	Project 2019-02	BES Cyber System Information Access Management	CIP-004-6	Formal	8/6/20	9/21/20	Yes 9/17/20
427	Project 2015-09	Establish and Communicate System Operating Limits	CIP-014-3 FAC-003-5 FAC-011-4 FAC-013-3 FAC-014-3 PRC-002-3 PRC-026-2 TOP-001-6 IRO-008-3	Formal	10/23/20	12/7/20	Yes 12/7/20
428	Project 2020-05	Modifications to FAC-001-3 and FAC-002-2	SAR	Informal	11/12/20	12/11/20	Yes 12/11/20
429	Project 2018-03	Standard Efficiency Review Retirements	FAC-008-4	Formal	11/30/20	1/13/21	Yes 1/13/21
430	Project 2020-06	Verifications of Models and Data for Generators SAR	MOD-026-1 MOD-027-1	Formal	12/16/20	1/14/21	Yes 1/14/21
431	Project 2019-04	Modifications to PRC-005-6 SAR	PRC-005-6	Formal	1/14/21	2/26/21	Yes 2/26/21
432	Project 2019-06	Cold Weather	EOP-011-2 IRO-010-4 TOP-003-5	Formal	1/27/21	3/12/21	Yes 3/12/21
433	Project 2019-06	Cold Weather	EOP-011-2 IRO-010-4 TOP-003-5	Formal	4/2/21	4/26/21	Yes 4/26/21
434	Project 2017-01	Modifications to BAL-003 White Paper	BAL-003-2	Informal	3/29/21	4/27/21	Yes 4/27/21
435	2020 Periodic Review Standing Review Team	Standards Grading	Standards Grading	Formal	3/22/21	5/5/21	Yes 5/5/21
436	Project 2019-02	BES Cyber System Information Access Management	CIP-004-X CIP-011-X	Formal	3/25/21	5/10/21	Yes 5/10/21
437	Project 2020-04	Modifications to CIP-012	CIP-012	Formal	4/26/21	6/9/21	Yes 6/9/21
438	2021 Standards Grading	2021 Periodic Review Standards Review Team – Standards Grading	21 Eligible Standards	Informal	6/4/21	7/19/21	Yes 7/19/21
439	Project 2021-05	Modifications to PRC-023	PRC-024	Informal	6/29/21	7/28/21	Yes 7/28/21

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440	Project 2021-06	Modifications to IRO-010 and TOP-003	IRO-010-2 TOP-003-3	Informal	7/8/21	8/6/21	Yes 8/6/21
441	Project 2019-04	Modifications to PRC-005-6 SAR	PRC-005-6	Formal	7/27/21	8/25/21	Yes 8/25/21
442	2022-2024	Reliability Standards Development Plan	Reliability Standards Development Plan	Informal	7/30/21	8/30/21	Yes 8/30/21
443	Project 2016-02	Modifications to CIP Standards	CIP-002-7 CIP-003-Y CIP-004-Y CIP-005-8 CIP-006-7 CIP-007-7 CIP-008-7 CIP-009-7 CIP-010-5 CIP-011-Y CIP-013-3	Formal	6/30/21	9/1/21	Yes 9/1/21
444	Project 2020-03	Supply Chain Low Impact Revisions	CIP-003-8	Formal	8/27/21	10/11/21	Yes 10/11/21
445	Project 2021-07	Extreme Cold Weather Grid Operations, Preparedness, and Coordination	BAL EOP IRO TOP Or Other Standards	Formal	11/22/21	12/21/21	Yes 12/21/21
446	Project 2020-04	Modifications to CIP-012	CIP-012	Formal	11/30/21	1/24/22	Yes 1/24/22
447	Project 2020-05	Modifications to FAC-001-3 and FAC-002-2	FAC-001 FAC-002	Formal	12/7/21	1/31/22	Yes 1/31/22
448	Project 2021-06	Modifications to IRO-010 and TOP-003	IRO-010 TOP-003	Informal	1/11/22	2/9/22	Yes 2/9/22
449	Project 2020-02	Modifications to TPL-001-5.1 and MOD-032-1	TPL-001-5.1 MOD-032-1	Informal	2/1/22	3/2/22	Yes 3/2/22
450	Project 2022-01	Reporting ACE Definition and Associated Terms	SAR	Informal	2/9/22	3/10/22	Yes 3/10/22
451	Project 2021-02	Modifications to VAR-002	SAR	Informal	3/9/22	4/6/22	Yes 4/6/22
452	Project 2016-02	Modifications to CIP Standards	CIP-002-7 CIP-003-Y CIP-004-Y CIP-005-8 CIP-006-7 CIP-007-7 CIP-008-7 CIP-009-7 CIP-010-5 CIP-011-Y CIP-013-3	Formal	2/18/22	4/11/22	Yes 4/11/22

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453	Project 2020-03	Supply Chain Low Impact Revisions	CIP-003-8	Formal	2/25/22	4/15/22	Yes 4/15/22
454	2022 Standards Grading	Standards Grading	PER-003-2 PER-005-2 PER-006-1 TPL-007-4	Informal	4/20/22	6/3/22	Yes 6/3/22
455	Project 2021-07	Extreme Cold Weather Grid Operations, Preparedness, and Coordination	EOP-011-3 EOP-012-1	Formal	5/19/22	6/21/22	Yes 6/17/22
456	Project 2020-06	Verifications of Models and Data for Generators	MOD-26-2	Formal	5/20/22	7/6/22	Yes 7/6/22
457	Project 2020-02	Modifications to PRC-024 (Generator Ride-through)	PRC-024-3	Formal	5/31/22	7/14/22	Yes 7/14/22
458	Project 2022-03	Energy Assurance with Energy-Constrained Resources	EOP and TOP	Informal	6/22/22	7/21/22	Yes 7/21/22
459	Project 2021-04	Modifications to PRC-002	PRC-002	Formal	6/9/22	7/25/22	Yes 7/25/22
460	Project 2020-03	Supply Chain Low Impact Revisions	CIP-003-8	Formal	7/6/22	8/19/22	Yes 8/19/22
461	Draft 2023-2025	Reliability Standards Development Plan	RSDP	Formal	7/26/22	8/24/22	Yes 8/24/22
462	Project 2021-07	Extreme Cold Weather Grid Operations, Preparedness, and Coordination	EOP-012-1	Formal	8/3/22	9/1/22	Yes 9/1/22
463	Project 2017-01	Modifications to BAL-003 – Phase II	BAL-003-2	Formal	7/25/22	9/7/22	Yes 9/7/22
464	Project 2022-04	EMT Modeling SAR	FAC-002 MOD-032 TPL-001	Formal	8/11/22	9/13/22	Yes 9/13/22
465	Project 2016-02	Modifications to CIP Standards	CIP-002-7 CIP-003-Y CIP-004-Y CIP-005-8 CIP-006-7 CIP-007-7 CIP-008-7 CIP-009-7 CIP-010-5 CIP-011-Y CIP-013-3	Formal	8/17/22	10/7/22	Yes 10/7/22
466	Project 2021-04	Modifications to PRC-002	PRC-002-3	Formal	9/26/22	11/10/22	Yes 11/10/22
467	Project 2020-04	Modifications to CIP-012	CIP-012	Formal	10/3/22	11/16/22	Yes 11/16/22

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468	Project 2021-01	Modifications to MOD-025 and PRC-019	MOD-025-2 PRC-019-2	Formal	9/29/22	11/17/22	Yes 11/17/22
469	Project 2021-05	Modifications to PRC-023	PRC-023-6	Formal	10/10/22	12/2/22	Yes 12/2/22
470	Project 2021-06	Modifications to IRO-010 and TOP-003	IRO-010-2 TOP-003-3	Formal	10/25/22	12/15/22	Yes 12/15/22
471	Project 2021-03	CIP-002 Transmission Owner Control Centers	CIP-002	Formal	11/22/22	12/21/22	Yes 12/21/22
472	Project 2021-02	Modifications to VAR-002	VAR-002-4.1	Formal	10/31/22	1/13/23	Yes 1/13/23
473	Project 2020-06	Verifications of Models and Data for Generators	MOD-26-2	Formal	11/21/22	1/18/23	Yes 1/18/23
474	SPM	Standard Processes Manual	SPM	Formal	1/18/23	3/6/23	Yes 3/6/23
475	Project 2022-01	Reporting ACE Definition and Associated Terms	ACE Definition Master List	Formal	1/31/23	3/16/23	Yes 3/16/23
476	Project 2023-02	Performance of IBRs	PRC-004-6	Formal	2/22/23	3/23/23	Yes 3/23/23
477	Project 2021-03	CIP-002 Transmission Owner Control Centers	CIP-002	Formal	3/2/23	3/31/23	Yes 3/31/23
478	Project 2021-07	Extreme Cold Weather Grid Operations, Preparedness, and Coordination	EOP-011-4 TOP-002-5	Formal	2/28/23	4/13/23	Yes 4/13/23
479	Project 2023-03	Internal Network Security Monitoring (INSM)	CIP-005-7 CIP-010-4 CIP-013-2	Formal	4/6/23	5/5/23	Yes 5/5/23
480	Project 2022-02	Modifications to TPL-001 and MOD-032	TPL-001 MOD-032	Informal	4/13/23	5/12/23	Yes 5/12/23
481	Project 2023-04	Modifications to CIP-003	CIP-003-9	Formal	3/31/23	5/15/23	Yes 5/15/23
482	SPM	Standard Processes Manual	Appendix 3A	Formal	4/13/23	5/30/23	Yes 5/30/23
483	Project 2017-01	Modifications to BAL-003 – Phase II	BAL-003-2	Formal	4/18/23	6/1/23	Yes 6/1/23
484	Project 2021-01	Modifications to MOD-025 and PRC-019	MOD-025-2 PRC-019-2	Formal	4/25/23	6/8/23	Yes 6/8/23
485	Project 2021-06	Modifications to IRO-010 and TOP-003	IRO-010-2 TOP-003-3	Formal	5/5/23	6/21/23	Yes 6/21/23
486	Project 2021-02	Modifications to VAR-002	VAR-002-4.1	Formal	5/10/23	6/23/23	Yes 6/23/23
487	Project 2021-03	CIP-002	CIP-002	Informal	6/13/23	7/12/23	Yes 7/12/23

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
488	Project 2022-02	Modifications to TPL-001 and MOD-032	TPL-001 MOD-032	Formal	5/13/23	7/14/23	Yes 7/14/23
489	Project 2021-03	CIP-002	CIP-002	Formal	7/20/23	8/18/23	Yes 8/18/23
490	RSDP	Reliability Standards Development Plan	RSDP	Informal	7/24/23	8/22/23	Yes 8/22/23
491	Project 2023-06	CIP-014 Risk Assessment Refinement	CIP-014	Formal	7/26/23	8/24/23	Yes 8/23/23
492	Project 2023-05	Modifications to FAC-001 and FAC-002	FAC-001-4 FAC-002-4	Formal	8/9/23	9/7/23	Yes 9/7/23
493	Project 2023-01	EOP-004 IBR Event Reporting	EOP-004-5	Formal	7/28/23	9/11/23	Yes 9/11/23
494	Project 2021-07	Extreme Cold Weather Grid Operations, Preparedness, and Coordination	EOP-011-4 TOP-002-5	Formal	8/24/23	9/12/23	Yes 9/12/23
495	Project 2021-04	Modifications to PRC-002	PRC-002-3 PRC-028-1	Formal	8/1/23	9/14/23	Yes 9/14/23
496	Project 2023-07	Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather	TPL-001-5.1	Informal	8/29/23	9/27/23	Yes 9/27/23
497	Project 2022-03	Energy Assurance with Energy-Constrained Resources	TOP-0XX-X	Formal	9/13/23	10/5/23	Yes 10/5/23
498	Project 2021-08	Modifications to FAC-008	FAC-008	Formal	9/5/23	10/19/23	Yes 10/19/23
499	Project 2020-06	Verifications of Models and Data for Generators	MOD-26-2	Informal	9/18/23	10/24/23	Yes 10/24/23
500	Project 2022-01	Reporting ACE Definition and Associated Terms	Definition	Formal	9/14/23	10/13/23	Yes 10/30/23
501	Project 2020-04	Modifications to CIP-012	CIP-012	Formal	9/19/23	11/2/23	Yes 11/2/23
502	Project 2021-02	Modifications to VAR-002-4.1	VAR-002-4.1	Formal	9/22/23	11/6/23	Yes 11/6/23
503	Project 2023-08	Modifications of MOD-031 Demand and Energy Data	MOD-031	Informal	10/10/23	11/8/23	Yes 11/8/23
504	Project 2021-03	CIP-002	CIP-002-Y	Formal	9/26/23	11/9/23	Yes 11/9/23
505	Project 2022-02	Modifications to TPL-001 and MOD-032	TPL-001 MOD-032	Formal	10/6/23	11/20/23	Yes 11/20/23

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
506	Project 2016-02	Modifications to CIP Standards Draft 5	CIP-003-10 CIP-004-8 CIP-005-8 CIP-007-7 CIP-010-5	Formal	10/3/23	11/29/23	Yes 11/29/23
507	Project 2021-07	Extreme Cold Weather Grid Operations, Preparedness, and Coordination Phase 2	EOP-012-2	Formal	10/27/23	11/30/23	Yes 11/30/23

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

November 30, 2022

Subject: NPCC Corporate Goal II-1 --- Develop Future Revisions to Directory No.1 to Address Reliability Contributions and Challenges of Changing Technologies and Load Characteristics.

Members, Regional Standards Committee (RSC).

The NPCC Board of Directors has established a 2022 NPCC Corporate Goal to:

Develop future revisions to NPCC Directory #1 to address reliability contributions and challenges of changing technologies and load characteristics.

The goal was informed by the extraordinary changes to the power generation and load characteristics of the Bulk Power System.

Consequently, a *Roadmap to Implement Future Revisions to Directory No.1* was developed to initiate a reliability discussion and provide a path forward to the appropriate NPCC technical groups and committees.

The Roadmap document examines the current issues confronting the industry (Energy Adequacy (all hours), Resource Adequacy Metrics, Essential Reliability Services, Electrification Load Forecasting Issues) and highlights specific portions of Directory No. 1 that should be considered for revision in order to address these challenges.

The initial version of this Roadmap was provided to the Task Force on Coordination of Planning (TFCP) and the Task Force on Coordination of Operation (TFCO) for review and comment. An additional comment period for the Reliability Coordinating Committee (RCC) and the RSC was conducted, and comments were incorporated into the draft as applicable.

Accordingly the *Roadmap to Implement Future Revisions to Directory No.1* is presented to the RSC for endorsement.

Gerry Dunbar
Director, Reliability Standards and Criteria

Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas - 10th Floor
New York, New York 10018
O: (212) 205-7060 • **C:** (917) 608-5325
gdunbar@npcc.org • www.npcc.org

NPCC Directory #1 *Design and Operation of the BPS*

Roadmap to Implement Future Revisions to Address Reliability Contributions and Challenges Brought Forward by Changing Technologies and Load Characteristics

Draft for RSC Endorsement
December 8, 2022

Background:

The electric industry is undergoing two significant simultaneous and accelerating transitions:

(1) To distributed decarbonization of electricity generation[1].
(2) To further electrification of the economy (i.e., Building Heat Pump based Electrification, and Electric Vehicle charging).

Some Areas within the NPCC Region have mandatory future zero carbon goals through legislation which are required to be achieved in certain future years.

In recognition of these extraordinary simultaneous changes to the power generation and delivery system technologies and load characteristics, the NPCC Board of Directors established a NPCC Corporate Goal for 2022 (#II-1)[2] to:

> *Develop future revisions to NPCC Directory #1 to address reliability contributions and challenges of changing technologies and load characteristics.*

Prologue:

This roadmap has been developed in accordance with the NPCC Strategic focus area to '*reliably integrate the resources brought forward by societal decarbonization*,' on a future schedule established by the Task Force on Coordination of Planning (TFCP) and the Task Force on Coordination of Operation (TFCO) which share jurisdiction over Directory #1.

Notwithstanding, the current administrative review of Directory #1, any future revisions resulting from the proposed review will meet the NPCC Reliability Principles shown in Appendix A, and the Definition of Adequate Level of Reliability shown in Appendix B.

Recent power system disturbance events, and energy and capacity shortfalls in Texas and California[3] have highlighted the need to reexamine the design basis for the NPCC Bulk Power System. The NPCC Board of Directors has directed that the existing design basis for both operations and planning be

[1] Several states and Canadian provinces have legislated varying timelines and degrees of reduced or eliminated carbon emissions with programs that increases electrical demand
[2] NPCC 2022 Corporate Reliability Goals
[3] See CAISO Summer 2022 Performance Report. The report outlines the challenges and future steps needed to address variable/intermittent generation and load side changes emanating from the accelerating transition to renewable resources. Several areas for improvement are noted starting on page 15.

reviewed in order to stay ahead of the rapid changes that are occurring within the industry to assure the continued reliable operation of the NPCC Bulk Power System.

While other efforts, most notably within NERC, are underway, it may not be prudent for NPCC to await these outcomes. For example, the passage of the U.S. Inflation Reduction Act and Bipartisan Infrastructure Law are expected to accelerate the transition toward carbon free generating resources[4]. Additionally, NERC's own experience[5] with NERC development projects suggests that it can take longer than anticipated for an ERO wide consensus on standards and/or guidance to be finalized.

NPCC Members have for many years adapted to late arriving NERC standard requirements and the development of NPCC's Criteria should be an initiative-taking and forward-looking process that does not risk having events overtake the ability of the reliability Criteria to address these emerging challenges.

System resilience (Appendix C) has always been a natural and integral part of the NPCC Criteria, and these revisions will further enhance that component of the reliability Criteria, especially in light of the greater variability of generating resources and load (reference Appendix A). Likewise, extreme weather events are a reality that should be reexamined in any review that considers the enhancement of the design Criteria of the Northeastern North American Bulk Power System.

Furthermore, some NPCC Areas are already exploring additional resource adequacy metrics for use in supplementing the existing Criteria and this effort will work in parallel with activities underway in the industry (e.g., US DOE, NERC) to examine and develop one or more additional design Criteria which may be used to modify and enhance the current resource adequacy methodology.

Finally, the TFCP and the TFCO will determine all schedule and scoping initiatives during any future review of Directory #1.

Next Steps:

In light of the changes in power system resources and their performance profiles, the focus of this roadmap is to provide NPCC members with guidance on the review of NPCC's Directory # 1-*Design and Operation of the Bulk Power System*, which is the primary document NPCC Members use to design their systems to assure reliable performance of the electric systems within and between the five Areas[6] that constitute the NPCC Region.

Some observations on the current version of Directory #1 include:

- The Resource Adequacy Criteria and associated metric currently in Directory #1 were developed and implemented at a time when meeting peak demand in an Area's peak season was appropriate as the sole design basis used for projecting resource adequacy. It was assumed that if the peak season demand could be reliably[7] served, all other periods during the year would be

[4] See NREL Report 81644 – Examining Supply-side Options to Achieve 100% Clean Electricity by 2035
[5] See NERC's October 2022 Whitepaper: Enhancing NERC Standard Processes wherein NERC identifies several standards development project which have taken inordinately long periods of time to come to fruition, page 3.
[6] The NPCC geographic region includes the State of New York and the six New England states as well as the Canadian provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia.
[7] Reference Requirements 4-6 in the current version of D1

adequately served. That may no longer be the case for all NPCC Areas due to accelerating industry changes.

- Variable resources upon which the renewable resource mandates are dependent, will cause the power system to become more reliant upon generating resources that are not dispatchable. This fundamental change in resource availability is not adequately covered or considered in the current Directory #1 construct.
- The most severe single contingency for some NPCC Area's may be a weather event (wind lull, or solar lull) or a gas pipeline contingency and this should be considered in a revision of Directory #1 as these risks have been identified[8].

In the NPCC Region, Bulk Power System (BPS) Planning[9] (Design and Operation) methods must identify and adopt new processes which in the opinion of its Members are needed to evaluate, identify, and mitigate risks to reliability on an initiative-taking and preemptive basis.

As outlined in the NPCC Strategic Plan 2022-2025[10], NPCC has taken note of the need to enhance system resilience, assure energy self-sufficiency for NPCC as a whole and within each Area while reliably integrating the generating resources brought forward by societal de-carbonization objectives. NPCC, in its Strategic Plan, focuses its efforts on supporting NERC and ERO activities to develop resilience metrics by reviewing and updating NPCC Reliability Criteria[11]

The Key Reliability Challenges have already been clearly identified by the Electricity Industry and its Stakeholders:

These industry changes may require significant modifications to the NPCC Criteria contained in Directory #1 in order to adequately manage future operating circumstances. From the NERC Reliability Issues Steering Committee (RISC) Prioritization Report there are several identified reliability risks which are currently not being addressed in Directory #1. The key NERC RISC Prioritization risks at issue for the Directory #1 review are:

- Changing Resource Mix
- Resource Adequacy and Performance (e.g., energy adequacy in all hours)
- Challenging Natural Events

Additionally, in its ERO Reliability Risk Priorities Report[12], the NERC RISC identifies numerous detailed risks to Bulk Electric System reliability. These risks are the result of significant changes to the power system which will require new models, more advanced tools, and grid infrastructure improvements.

New circumstances as expected by NERC's Board of Directors require new and revised Criteria and contingency testing. Examples may include the loss of a major gas pipeline, or in the context of the new

[8] For example in ISO NE: Letter of G. van Welie to DOE Energy Secretary Granholm August 29, 2022

[9] In this document the term Bulk Power System is used in reference to the elements determined to be part of NPCC's Bulk Power System by way of the A-10 testing; "Classification of Bulk Power System Elements"

[10] NPCC Working Draft STRATEGIC PLAN 2022-2025

[11] Pages 6-7 of the NPCC Working Draft STRATEGIC PLAN 2022-2025 covering resilience metrics, revising NPCC Reliability Criteria, Assessing gas-electric interdependencies, etc.

[12] NERC RISC Reliability Risk Priorities Report July 2021

renewable/inverter-based generation paradigm, a wind or solar lull will become a critical contingency test that should be examined to preserve resilience and reliability.

Directory #1's Current Objective:

The current objective of Directory #1 is to provide a "design-based approach" to the design and operation of the Bulk Power System to a level of reliability that will not result in the loss or unintentional separation of a major portion of the system for any of the contingencies referenced. The limited intent of this approach is to avoid instability, voltage collapse and widespread cascading that will impact a neighboring Area(s). Loss of small portions of a system (such as radial portions or local networks) may be tolerated provided these do not jeopardize the reliability of the remaining NPCC Bulk Power System.

The combined stresses of higher electric loads due to decarbonization (e.g., heating, transportation), challenging weather, and the replacement of legacy dispatchable generating resources with variable energy resources (solar, wind, battery-based storage) were not anticipated when the current Directory #1 Criteria was developed.

Within the NPCC Region, the technique for achieving its historically high level of reliability is to require that the Bulk Power System be designed and operated to meet the performance requirements for the representative contingencies as specified in Directory #1. These contingences, which were selected decades ago, should be reviewed to determine if they provide an adequate level of stress to evaluate the performance and resilience of the decarbonized NPCC Bulk Power System and if they simulate the appropriate challenging weather impacts on power system performance.

The contingencies for transmission stress testing, the projected loading levels (reflecting expected accelerating electrification trends), and simulation methods (limited ability to simulate inverter-based resource control system performance) currently in use by NPCC Members should be reviewed to consider these factors and analysis should be designed based on regional or local need or requirements.

A new stress testing paradigm should be developed by NPCC Members, to assure reliable operation of the Bulk Power System in the decarbonized, societal electrification in the future. At a minimum, contingency events should be selected and applied on Bulk Power System elements that represent present and emerging plausible situations.

Stressors of the Bulk Power System that should be considered as Directory #1 is reviewed and modified:

The most significant applicable **stressors** of the Bulk Power System that are occurring in the industry include:

- **Resource Adequacy Assessment Scopes—Network Realities vs. Political Boundaries:** Current resource planning and resource adequacy assessments are often performed using a political or utility boundary that does not adequately consider potentially significant inter-area electrical impacts and interactions due to the interconnected nature of the bulk power system outside of that limited scope. The result may be resource, energy, and/or transmission capacity insufficiencies in an operational timeframe.

- **Resource Adequacy Does Not Necessarily Equal Energy Adequacy:** Resource adequacy assessments have focused on generation and transmission capacity available to serve peak demand. With the previous resource mix, real-time energy adequacy was assumed under that capacity umbrella and transmission was not highlighted as a requirement; however, recent challenging weather events have shown energy adequacy in all hours to be a new dimension of significant risk given the changing resource mix and system performance versus assumptions used in previous resource mix studies.

- **Technology with Different Design and Performance Characteristics:** The continued integration of substantial amounts of new resource technologies (e.g., DERs, grid and distribution system-connected inverter-based resources, energy storage) will result in challenges in forecasting anticipated net demand. The dynamic and transient performance and response of these technologies also brings new challenges including control and protection systems complexity.

- **Ensuring Sufficiently Flexible Resources to Meet Demand:** With the expected volume of wind and solar resources and their characteristic fuel-driven commitment and dispatch capabilities as well as the characteristics of other resources that may constrain their near-term ability to respond, sufficient amounts of flexible resources will be needed to meet demand when the less flexible resources are unavailable. The flexible resources will need to be dispatchable within the forecasting period of the fuel driven or less flexible resources becoming unavailable.

With the increasing load and variability of resources the current approach embedded in Directory #1 (e.g., the do no harm to any neighboring Area principle) is likely to be not adequate for a decarbonized future where multiple NPCC Areas are expected to become energy limited for an unknown number of hours per year. Furthermore, it is not known if those hours will overlap and if any overlap will limit inter Area assistance in times of need; each Area may need to look to its internal resources and limit reliance on a neighboring Area(s) for support in times of need more than it does today.

Planning to avoid negative impacts to neighboring Areas will neither preserve nor enhance the reliability of any Area in the face of the accelerating industry changes. In the prior paradigm all or most generating capacity was fully controllable and dispatchable and therefore a capacity management-based approach with its Loss of Load Expectation Criteria (of disconnecting firm load due to peak season generating resource deficiencies Criteria , on average, no more than 0.1 days per year) was adequate. Now an all-hours approach will be needed, and such an approach is not well supported by the existing language of the objective or the Directory #1 Criteria. This discussion should be undertaken by NPCC Members in the course of this effort.

The tables that follow identify those requirements and aspects of Directory #1 which are to be reviewed considering the foregoing discussion. The existing Criteria and the corresponding system stress related issue(s) are identified, along with a high-level description of the proposed task to address the risk issue and enhance or preserve power system reliability in the face of the changes outlined. While the NPCC

Member review activity is being conducted, consideration should be given to these industry concerns in light of the challenging aspects of the changing weather environment in each Area:

- Energy Adequacy (all hours)
- Resource Adequacy (potential additional metrics which may provide more insight into system reliability performance)
- Essential Reliability Services (frequency response and voltage support capability of New Renewable Generation Technology for examples)
- Demand magnitude and yearly/daily profile changes due to electrification
- Electric -Gas interdependency (gap in the existing Criteria)
- Inverter Based Resources ride through after routine system disturbances (gap in the existing Criteria)

Furthermore, consideration should be given to what similar activities NERC is currently engaged in that may be used to enhance NPCC requirements to the extent possible while avoiding unnecessary duplication.

The following Table (Table#1) outlines a proposed approach to the multi-faceted task at hand.

Table 1 Existing Directory #1 Objective and Requirements Review

	Current Directory #1 Objective, Requirements and Appendices	Industry Risk or Challenge	Suggested Task definitions to Manage Future Reliability and Resilience Risks
1	Objective statements in Directory #1	Consider all the power system (generation, delivery system, and load) stressors noted in the forgoing paragraphs of this document.	Develop new Directory #1 objective statement(s) that go beyond the current approach of providing design Criteria that simply avoids limiting negative reliability impacts to neighboring Areas. A whole of NPCC approach should be considered recognizing the interdependence between Areas may be greater than ever.
2	R4 Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year.	LOLE based methods may work as a performance metric in a generation capacity-oriented system where on peak (seasonal) capacity can be planned and its operation scheduled with some reasonable level of assurance that it will perform. In a largely Energy limited resource future, the resource adequacy performance measurement approach and related metrics need to address energy adequacy in all hours several years in advance for planning purposes and several weeks in advance for operational purposes.	Review resource adequacy related modelling methods and work . Identify new metrics implemented by NPCC Member s and other industry organizations, (DOE, Energy labs, IEEE, EPRI, etc.) and explore changes to NPCC resource adequacy metrics used to establish NPCC Criteria.[13] Consider new processes to be implemented in a modified R4 that involve a suitable all-hours Energy Adequacy related modelling approach and related Criteria. Example metrics to be considered include, but are not limited to, LOLE, LOLH, EUE, and largest single curtailment of firm load. Maintaining the current LOLE Criteria is an option if it deemed by NPCC members to be adequate to the purpose. However additional metrics may

[13] See reports from the NYSRC and NRRI on the subject of resource adequacy metrics and methods for examples.

			provide better and more meaningful measures of reliability and resilience.
3	R6 Each Reliability Coordinator shall coordinate outages and deratings of resources to verify adequate resources will be available to meet the forecasted demand and reserve requirements. Appendix F provides guidance for Operational Planning Coordination.	Forecasting electric demand will be even more challenging as new load patterns emerge. The increased magnitude of Variable Energy Resources is already presenting challenges to short-term operational planning and long-term system expansion planning activities. The increase to building and transportation electrification, changing weather patterns and advanced pricing methods to provide load modifying incentives to end users at the retail level are also confounding factors creating challenges for load forecasting processes.	Identify best practices used for near term operational and long-term load forecasting techniques in light of the changing resources and load mix[14]. Consider modifying Directory 1 Appendices to encourage the approaches in use and to apply in load forecasting and resource adequacy on an hourly basis considering the stressors listed above. Review Appendix F and consider more comprehensive Multi Area collaboration in the light of forecasted wide, multi-area weather events. Address issues related to simultaneous stressors impacting neighboring Areas and the increasing likelihood of the unavailability of any assistance from neighboring Areas during such events. Develop revisions to Appendix F in light of the key stressors listed above.
4	R7 Each Transmission Planner and Planning Coordinator shall plan its bulk power system to have sufficient transmission *capability to meet the respective requirements as specified in Table 1* while serving forecasted demand	Issue – resilience in light of greater dependence on the reliable performance of the transmission system to deliver remotely located renewable resources to load areas.	Because dependence on transmission is likely to increase, review Directory #1 Table 1. Evaluate contingency tables considering new power system stressors listed above, and if necessary, make recommendations for Criteria changes, Table 1 changes or the changes to the

[14] Two examples are the recent NYISO decision to preserve 350 MW of operating reserve when calling for public appeals and the ISO-NE decision to forecast 27 days forward on an energy basis to deal with gas availability issues.

			performance assessment expectations ii, v, viii, to Table 1.
5	R8 Each Transmission Planner and Planning Coordinator shall assess the impact of the extreme contingencies listed in Table 2. Appendix C provides guidance for testing and analyzing extreme contingencies	Issue -– resilience in light of greater dependence on the reliable performance of the transmission system to deliver remotely located renewable resources to load areas during challenging weather events.	Review and consider modifying Directory #1 Table 2 to consider a wide multi-Area weather event occurring simultaneously, and/or sequentially over multiple operating areas greater than a single NPCC Area that will stress the power delivery system**.** In light of the key stressors listed above make recommendations, if necessary, for Table 2 changes, Criteria changes and review the Performance Assessment expectations i, ii, for changes.
6	R9 Each Transmission Planner and Planning Coordinator shall assess the impact of extreme system conditions, one condition at a time, subject to contingencies as listed in the "Extreme System Conditions" category of Table 2.	With the increase in variability of resources, to preserve resilience and reliability, operating margin policies should be reviewed to prepare for occurrence of challenging weather conditions which may occur in any hour, not just during the peak seasonal hour.	R9 Consider developing modifications and potential new Criteria for operating reserve margin requirements in each NPCC Operating Area, tailored to its penetration of variable, intermittent resources, to ensure resource adequacy in all hours under challenging weather conditions including the key stressors listed above.
7	Appendix D - Guidelines for Area Review of Resource Adequacy	The all-hours requirement for resource adequacy is not addressed in the current version of Appendix D and is a clear present risk going forward.	Reference the Task related to R4 above considering new metrics for Resource Adequacy. Consider adding a new component to Directory #1 Appendix D activities to require a simultaneous, all-hours forecast analysis for the NPCC region as a whole to assure that no Area is establishing an infeasible, neighboring system assistance reliance for the expected future when intermittent resources form a major component of the resource portfolio in a number of NPCC Areas.

8	Appendix F	The all-hours requirement for resource adequacy is not addressed in the current version of Appendix F	Reference the task in R6 and add a new component to the Appendix F activities to require a simultaneous, all- hours analysis for the NPCC region as a whole (rather than twice yearly as specified in 2.1 and 2.2), to assure that no Area is establishing an infeasible neighboring system assistance reliance for the expected future when intermittent resources form a major component of the resource portfolio in a number of NPCC Areas.

Identifying and Filling the Gaps:

The stressors listed above have already created reliability gaps with respect to the existing Bulk Power System design Criteria methods for some NPCC Areas. These gaps have become apparent as a result of events in other areas of North America and prudence dictates that NPCC adopt a lessons learned approach from those events and adapt any associated methods and processes. For example, while Directory # 1 has had within it a resource adequacy topic for many years, there is no specific Criteria to address electric-gas interdependency. The decision to include new or modified Criteria to consider fuel dependency risks explicitly is a topic for consideration by NPCC Members .

The recent performance limitations of Inverter-based Resources (IBR) in the period immediately following a transmission line trip and reclose operation will likely require new planning or interconnection Criteria. This topic should be considered for inclusion in the revised NPCC Directory #1 in order to provide uniform NPCC-wide design Criteria on this issue before additional significant amounts of inverter-based resources are commissioned[15][16].

The table below identifies some high-profile specific issues which are not covered in the existing NPCC Directory #1 and that should either be added as new topics, or melded into the revised document as a review of existing Criteria are conducted.

Table 2 – Activities to address reliability and resilience gaps

Issue or challenge – tie to stressor	Proposed Task to Manage the issue
Electric – Gas interdependency	Consider including in expanded existing Criteria, or create new Criteria to mitigate the impacts on resilience and reliability of gas supply disruptions, which may represent a more impactful electric system contingency than the purely electric system contingencies currently used as simulation-based stress tests.
Common mode failure to stay on-line of Inverter Based Resources (IBR)	Consider including in expanded existing Criteria, or create new Criteria to address IBR performance gaps (stability, disturbance ride through, frequency control) until all new IBR based generating technology can be made compliant with IEEE 2800-2022 which provide uniform technical minimum requirements for the interconnection, capability, and lifetime performance of inverter-based resources. Recognize that the amount of pre-IEEE-2800 IBR generation is significant and will not likely be required to modify their control systems.

[15] NERC Guidance on Inverter based Resources March 2020

[16] EPRI-NAGF-NATF-NERC Joint Webinar on IEEE Standard 2800-2022

Conclusion:

Initial drafts of this document were reviewed and commented on by the Reliability Coordinating Committee (RCC), the Regional Standards Committee (RSC), the TFCP and the TFCO. All comments were considered and where applicable, enhancements to the document are reflected in this version.

Two main and opposing viewpoints received from NPCC Members were as follows: 1) Since NERC is actively engaged in several of the technical areas of concern, NPCC should wait to conduct a further review of the Criteria in Directory #1 until NERC has completed its work 2) The unprecedented pace of change within the industry and the lack of timeliness and urgency (as reported by NERC itself) of its standard development projects suggests that NPCC should move forward expeditiously and address these issues within its Criteria.

As suggested by an NPCC Member, an approach towards reconciling these opposing views, would be to divide the Directory #1 review effort into two phases. The scope of the first phase would be tailored to address only resource adequacy issues. Upon completion of the first phase other elements of the Criteria (i.e. contingency assessments) could be considered and informed by the outcome of the first phase. In this manner, progress on the Criteria can be achieved while also allowing time for NERC efforts to develop.

The intent of this Roadmap is to initiate the reliability discussion and provide a path forward to the appropriate NPCC technical groups and committees.

Appendix A – NPCC Reliability Principles

NPCC's reliability principles (taken from the NPCC 2018 Strategic Review) include:

1. Focus on the most important system components: To focus resources to those portions of the power delivery system most important (critical) to overall reliability, NPCC Members employ and are updating the mechanism(s) for identifying those facilities that are most critical to the reliable planning and operation of the power delivery assets in the NPCC region . These critical facilities collectively are identified as the NPCC Bulk Power System .

2. Application of Criteria beyond NERC requirements to identified critical facilities: Where, in the opinion of NPCC's Membership, the NERC standards do not specify a necessary performance or design outcome in each technical, operation or planning area, NPCC Criteria govern the design of their respective portions of the NPCC Bulk Power System planning and operation activities.

3. NPCC Members support the Criteria: NPCC's Full Members in accordance with the NPCC Bylaws are committed to designing and operating their systems to meet the NPCC Criteria under peer review of the NPCC Full Members.

4. No conflict with NERC Requirements: The NPCC Criteria supplement, improve upon where necessary, benefit, and do not conflict with or duplicate the results-based performance requirements of NERC standards where they apply to the NPCC Bulk Power System. NPCC adjusts its regional Criteria to retire or adapt to any new NERC requirements as they come into effect, as necessary.

5. Include design specifications where needed: The NPCC Criteria and related guidelines and procedures provide design Criteria and practices to assure implementation. This contrasts with NERC which is limited through its standards requirements to only identifying a minimum "reliability result." NPCC Directories go into greater detail regarding how to accomplish a given reliability result addressing the "how" of a given reliability result is to be achieved.

6. Resilience has always been an element of NPCC Criteria: Based on experience, resilience is a necessary constituent part of reliability, and it is important both to electricity consumers and regulatory authorities in NPCC's footprint. See Appendix C for details on the attributes of Resilience.

Appendix B – Adequate Level of Reliability

The basic attribute of a reliable bulk power system of having adequate generating resources and transmission delivery capability to reliably meet projected customer electricity demand and energy requirements[17]. The ERO's definition of an Adequate Level of Reliability[18] still holds true no matter what future evolves and can provide the guidance needed for this NPCC review of Directory #1.

The Bulk-Power System ("System") will achieve an adequate level of reliability when it possesses the following characteristics:

1. The System is controlled to stay within acceptable limits during normal conditions.

2. The System performs acceptably after credible Contingencies.

3. The System limits the impact and scope of instability and cascading outages when they occur.

4. The System's Facilities are protected from unacceptable damage by operating them within Facility Ratings.

5. The System's integrity can be restored promptly if it is lost; and

6. The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, considering varying load and generation patterns, scheduled, and reasonably expected unscheduled outages of system components

Simulations are used to assess and analyze the impact of selected contingencies as a way to evaluate the adequacy of the generation and delivery systems. At a minimum, contingency events should be selected and applied on bulk power system elements that represent plausible situations.

[17] Current language from Directory #1

[18] ERO Definition of An Adequate Level of Reliability

Appendix C-Resilience

Resilience is a topic that has not been explicitly considered during past reviews during the development of the current version of Directory #1. The Strategic Review of the NPCC Criteria in 2018 , concluded that resilience is a necessary component of a reliable system. Previously resilience was not specifically called out as an element of the NPCC Criteria, however it is a reliability gap that should be addressed in the next review of Directory #1. Based on industry experience, resilience is now a necessary component of reliability, and it is important both to electricity consumers and regulatory authorities in NPCC's footprint. In the past NPCC Criteria provided substantial resilience benefits to the NPCC Bulk power system by providing or enhancing:

a. Robustness – The ability to absorb shocks and continue operating .

b. Resourcefulness – The ability to detect and manage a crisis as it unfolds.

c. Rapid recovery – The ability to get services back as quickly as possible in a coordinated and controlled manner.

d. Adaptability – The ability to apply new lessons from events.

Preservation of resilience will require that the Criteria in NPCC Directory #1 be reviewed considering the accelerating changes in the industry and in order for NPCC Member systems to stay ahead of unfolding industry developments.

RSC Meeting
December 7, 2023
Agenda Item #5.1.2

December 3, 2023

Members, Regional Standards Committee

Subject: Goal II-2 Incorporate Provisions of IEEE-2800 into NPCC Criteria

Ladies and Gentlemen:

In accordance with 2023 NPCC Corporate Goal II-2, a draft report providing recommendations for incorporating the provisions of IEEE-2800 *Standard for Interconnection and Interoperability of IBR's* was presented to the Reliability Coordinating Committee (RCC) and the Regional Standards Committee (RSC) for comment on September 1, 2023.

The report identifies the implications of Inverter Based Resource (IBR) penetration on Bulk Power System (BPS) reliability and addresses the impact on the functional reliability related areas of Protection, Operations (Reserve and Restoration) and Planning (Modelling/Validation), within the NPCC Criteria.

Specific recommendations for enhancing certain Criteria Requirements in Directory #1 *Design and Operation of the BPS*, and Directory #4 *System Protection* are provided, along with high level recommendations to consider the impact of IBR's during the next review of Directory #5 *Reserve*, Directory #8 *System Restoration* and Directory #11 *Disturbance Monitoring Equipment Criteria*.

Comments on the report were received from NPCC Members and incorporated into a final version of the report which is attached and publicly available on the NPCC website.

Gerry Dunbar
Director, Reliability Standards and Criteria

Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas - 4th Floor
New York, New York 10018
(917) 608-5325
GDunbar@NPCC.org

Recommendations for Incorporating Provisions of IEEE-2800-2022 and IBR Performance Requirements into the Applicable NPCC Criteria

Purpose:

The purpose of this report is to address NPCC 2023 Goal II-2 which states:

> *Develop proposed recommendations for incorporating provisions of IEEE-2800-2022 (Standard for Interconnection and Interoperability of IBRs)[1] (IEEE-2800) into the applicable NPCC Criteria. Present to RCC and RSC for input – by 10/23.*

The report identifies the implications of Inverter Based Resource (IBR) penetration on Bulk Power System (BPS) reliability in general and addresses in detail the impact on the specific functional reliability related areas of Protection, Operations (Reserve and Restoration) and Planning (Modelling/Validation), within the NPCC Criteria[2].

Using the processes specified in the NPCC Directory Development and Revision Manual, NPCC Full Members through their respective Task Forces, have an obligation to keep the NPCC Criteria consistent with the evolving ERO Standards and responsive to the rapidly changing nature of the NPCC BPS.

Accordingly, the technical guidance within IEEE-2800 should be considered by each NPCC Task Force and added to Criteria where applicable.

Reliability Risks Related to IBR

The concurrent, unexpected tripping of synchronous generation and the sudden reduction of power from many renewable IBR's during recent BPS events highlights the need to ensure the reliable operation of the NPCC BPS Areas which are also experiencing increased penetration of IBR's.

IBR technology has been identified by NERC and other industry participants as a significant change in the generating resource mix. Numerous NERC Major Disturbance Reports[3] have documented the risks to the reliable operation of the BPS due to a lack of uniform interoperability protocols.

The risks to power system reliability that have been identified through the NERC Major Disturbance Reports include:

- Unacceptable voltage and frequency ride-through performance of IBRs
- Unacceptable active power control after routine system disturbances

[1] IEEE-2800 – 2023 - Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems. (Note that additional components of IEEE-2800 related to verification and testing are currently under development).

[2] See NPCC Directories

[3] See NERC Major Event Analysis Reports dated August 2016, October 2017,Aril/ May 2018, May/June 2021, June 2022, April 2023.

- Unacceptable reactive power control after routine system disturbances
- Unacceptable dynamic active power support under abnormal frequency conditions
- Inadequate dynamic voltage support under abnormal voltage conditions
- Unacceptable negative sequence current injection
- Inadequate coordination between IBR control functions and existing power system protection systems and remedial action schemes.

Industry Response to IBR Reliability Risks:

Reliability[4] is the ability of the system to continue delivering electric service to consumers in the face of instability, uncontrolled events, or loss of system components. A highly reliable system provides continuous electric service to all customers when they demand it.

One of the industry responses to the identified IBR reliability risks has been the development of the IEEE-2800 IBR Interoperability Standard. This standard identifies the required interconnection performance requirements for IBR interconnected technology so that these facilities can be reliably connected to the transmission and sub-transmission power systems. Included in the IEEE- 2800 standard are performance requirements for IBR's (based on detected performance shortfalls and NERC disturbance analysis reports) including:

- Voltage and frequency ride-through,
- Active power control,
- Reactive power control,
- Dynamic active power support under abnormal frequency conditions,
- Dynamic voltage support under abnormal voltage conditions,
- Negative sequence current injection,
- System protection.

Directory Governance and the Authority Governing Interconnection Requirements (AGIR)

NPCC manages Regional Criteria[5] to preserve and enhance the reliable operation of the BPS in the NPCC Region. Pursuant to Article IV of the NPCC Bylaws, NPCC's Full Members are obligated to comply with the regionally specific Criteria contained it is Directories.

[4] NERC defines an adequate level of reliability (ALR) as follows:
The Bulk-Power System ("System") will achieve an adequate level of reliability when it possesses following characteristics:
1. The System is controlled to stay within acceptable limits during normal conditions;
2. The System performs acceptably after credible Contingencies;
3. The System limits the impact and scope of instability and cascading outages when they occur;
4. The System's Facilities are protected from unacceptable damage by operating them within Facility Ratings;
5. The System's integrity can be restored promptly if it is lost; and
6. The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

[5] NPCC Criteria in the form of its Directories are listed on the Criteria page of the NPCC website at: Directories (npcc.org)

'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.'

The Authority Governing Interconnection Requirements (AGIR) is a term used in IEEE- 2800 to identify which entities have the authority to require that the technical specifications in the IEEE-2800 standard are followed by interconnecting IBRs.

Currently, some NPCC Full Members serve as the AGIR [6] within their service areas and the language within the NPCC Directories may be adequate to permit these NPCC Full Members the latitude to include the IEEE- 2800 technical provisions in their respective, technical, and model simulation reviews. NPCC Full Members who are not the AGIR but may become the AGIR, do not have this technical obligation but may have that responsibility in the future.

Although NPCC is a governing body with region-wide reliability rule making authority through its Criteria, NPCC is not an AGIR as the term is used in the IEEE-2800 Standard.

An informal poll of the integration of IEEE- 2800 in the NPCC Areas reveals varying levels of involvement by NPCC Full Member AGIR entities. This ranges from full adoption of IEEE- 2800 as issued and approved by the IEEE, to partial adoption of portions of the IEEE- 2800 standard.

Need for Modifications to NPCC Criteria:

This report recommends that the Criteria within five NPCC Directories be considered for revisions by the respective NPCC Task Force(s) having authority over the documents.

Given the lengthy and deliberative processes in place with respect to NERC mandatory standards, and the accelerated pace of IBR penetration in certain NPCC Areas, the NPCC Criteria contained in its Directories should be reviewed at the earliest possible time. This urgency is driven by the accelerating reliability risks imposed on the NPCC BPS by IBR technology.

If interoperability of IBR technology is not addressed through the interconnection processes in each NPCC Area, it is likely that significant amounts of IBR will be interconnected to the NPCC BPS (in addition to the IBR based facilities already in place) without regard to the necessary interoperability requirements. This will lead to the potential for major system disturbance events, examples of which have already been well documented in other parts of the US as noted earlier.

Some Areas with aggressive public policy drivers for the adoption of renewable resources, have either already fulfilled or are in the process of fulfilling implementation of IEEE 2800-2022 within their minimum technical interconnection requirements. The recommended enhancements to NPCC Criteria, particularly within Directory #1, should provide the needed latitude and support for those Areas that currently do not have IEEE-2800-2022 referenced in their interconnection

[6] AGIR (from IEEE-2800) - A cognizant and responsible entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of an inverter-based resource (IBR) to the transmission system (TS). This may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc., or depending on jurisdiction, TS owner or TS operator.

requirements. The TFCP should consider the needs of these Areas during the next revision of Directory #1.

Directories to be Reviewed:

This report provides an initial assessment of the potential applicability of the IEEE-2800 interoperability provisions into the NPCC Criteria.

NPCC Directories that have been identified for this IEEE-2800 assessment:

- Directory #1 Design and Operation of the BPS
- Directory #4 System Protection Criteria
- Directory #5 Reserve
- Directory #8 System Restoration
- Directory #11 Disturbance Monitoring Equipment Criteria

Directory #1 – Design and Operation of the Bulk Power System

The intent of Directory #1 is to avoid instability, voltage collapse and widespread cascading outages. These reliability risks are related to many of the IEEE-2800 performance requirements listed above.

Historically and under the current Criteria within NPCC, loss of small portions of a NPCC Area's transmission system (such as radial portions) have been acceptable, provided that these losses do not jeopardize the reliability of the remaining NPCC BPS. Within the NPCC Region, the technique for achieving the acceptable level of reliability is to require that the NPCC BPS be designed and operated to meet the performance requirements for the representative contingencies as specified in Directory #1. However, considering only transmission contingencies as currently called for in Directory #1 may not be sufficient in the future depending on the level of non- IEEE-2800 compliant IBR resources in service within an Area. Expansion of the list of contingencies to include common mode resource loss of non-compliant IBR depending on the Area's magnitude of such facilities in comparison to the total resources in the Area, should be considered.

As highlighted in numerous system disturbance events, the lack of performance standards for IBR equipment and appropriate methodologies to verify that performance has led to system disturbances[7] which should be considered in the NPCC Design Basis (Directory #1).

Specific Directory#1 requirements that should be reviewed for applicability of IEEE-2800 provisions is as follows:

Directory #1-1.3 Objective

The Objective portion of Directory #1 provides that:

[7] See NERC Major Event Reports dated August 2016, April and May 2018, July 20, May/June 2021, June 2022.

' If an entity becomes aware of a contingency not on a BPS element that results in a significant adverse impact outside the local area, that entity must design and/or operate the system to respect that event.'

It is clear that non-IEEE-2800 compliant generation in an Area may become so great in the future that loss of the non- IEEE-2800 compliant generation would constitute a severe single contingency for the Area. The objective of Directory #1 should be reviewed and modified to address this development and the list of contingencies, beyond traditional transmission contingencies, should be reviewed. For new, yet undiscovered common mode failure of IBRs there is a risk that the industry may experience new contingencies that are not planned and operated to, which result in an unexpected loss of IBRs in large enough quantities and total magnitudes of MW loss that result in the reliability risk.

Directory #1- R1 and R2 - Information for Planning and Operational Assessments

R1 *Each Functional Entity that owns equipment shall submit verified information representing the physical or control characteristics of its equipment for system modelling and reliability analysis of the bulk power system in accordance with Requirement R2.*

R2 Each Planning Coordinator and Reliability Coordinator shall collect and maintain information needed for system modelling and reliability analysis of the bulk power system.

R2.1 System modelling information shall be submitted to an NPCC Task Force upon request.

While it is recommended that all IBRs be complaint with IEEE-2800, some Areas are considering grandfathering non-IEEE-2800 compliant IBR's. The recent proposed IBR rule from FERC did not require mandatory compliance with IEEE 2800 but left it up to NERC in the development of a three-year standards development project to specify what the performance requirements of IBR's should be. NPCC stakeholders should consider whether the requirement language in R1 and R2 should be more specific than any NERC requirements with specific citations to IEEE-2800 relating to models and model verification so that verified information representing the physical and control characteristics of IBR technology can be obtained related to:

- Voltage and frequency ride-through,
- Active power control,
- Reactive power control,
- Dynamic active power support under abnormal frequency conditions,
- Dynamic voltage support under abnormal voltage conditions,

Additionally, the language in R1 refers to "its" equipment; however, this should be modified to address all IBR equipment to which the Full Member system is connected regardless of ownership.

Directory #1- R4 – Resource Adequacy

R4 *Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year.*

R4.1 *Make due allowances for demand uncertainty, scheduled outages, and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.*

NPCC stakeholders should consider whether the language of R4 is adequate to address the intermittent nature of IBR performance (wind and solar). The portions of R4.1 that address deratings, and forced outages may require revision. Although, this consideration is not related to IEEE- 2800 technical guidance, resource adequacy in all hours (rather than an assessment at seasonal peak), is an important planning and operations concern due to the expected high penetration of IBR underway in certain Areas.

Directory #1- R10 – Transmission Planning

NPCC stakeholders should consider whether the language of R10 should be revised.

R10 *Each Transmission Planner and Planning Coordinator shall have procedures and implement a system design that ensures equipment capabilities are adequate for fault current levels with all transmission and generation facilities in service for all operating conditions which are not prohibited by a procedure and coordinate these procedures with materially affected Transmission Planner and Planning Coordinator Areas.*

As the penetration of IBR technology increases, the available fault current and inertia of the system declines. In a future low fault current, low inertia system, a thorough examination of the interaction of IBR control systems with existing system protection design should be considered. New requirement language ensuring that NPCC Full Members, which are also an AGIR, should consider fault current contribution scenarios for interconnecting IBR facilities.

Directory #1-Table 1

NPCC stakeholders should consider whether the Table#1 Category I Single Event performance requirements should be expanded to include common mode failure of non-IEEE-2800 compliant IBRs. Similar consideration for the recovery from IBR losses after a first Element loss in Category II should also be reviewed.

Also, in Category II, Extreme System conditions, IBR resource adequacy (loss of fuel, e.g., sun, or wind) should be added to the performance requirements list.

Directory #4 – System Protection Criteria

A key area of concern is the interoperability of IBR technology with existing protection systems. Currently NPCC Directory # 4 System Protection provides an important level of detail regarding the configuration of conventional protection systems by defining protection system component redundancy to meet the NPCC's more stringent reliability requirements.

However, Directory #4 does not consider the extensive deployment of IBR technology control systems which provide protective functions to the IBR inverters. The operation of these control systems has been demonstrated to conflict with the protection principles in Directory#4 since some of the IBR control functions also serve a protective function.

IEEE-2800 provides operating parameters for IBR control systems so they can be coordinated with existing protections systems without negative interactions.

NPCC stakeholders should consider the following sections of Directory #4 for enhancement:

Directory #4 - Appendix A Guideline and Recommendation for Bulk Power System Protection, Section 2.1.4:

> 2.1.4 *Whenever changes are anticipated in generating sources, transmission facilities, or operating conditions, Generator Owners, Transmission Owners, and Distribution Providers should review those protection system applications (i.e., settings, ac, and dc supplies) which can reasonably be expected to be impacted by those changes.*

To the extent that the interconnecting Full Member of NPCC serving as the AGIR is considering the interconnection of a new IBR resource, they should invoke Appendix A part 2.1.4 to provide for a full review of the interaction of the new IBR facility control system with the existing protection systems.

Accordingly, the NPCC Member serving as the AGIR will also determine the level of the interoperability specifications within IEEE- 2800 to implement when reviewing the impact of IBR controls systems and the interaction with existing protection systems.

NERC has advocated the use of Electromagnetic Transient Analysis (EMT) studies to address the interactions of IBR control systems with existing protective functions in stability studies. Reference to these NERC guidelines should be reviewed and considered for inclusion in NPCC Directory #4 Appendix A.

Directory #4 - Appendix A Guideline and Recommendation for Bulk Power System Protection, Section 2.4.9:

NPCC stakeholders should consider amending section #2.4.9 by adding IEEE-2800 to the existing list of IEEE standards in this section.

Appendix A Guideline and Recommendation for Bulk Power System Protection, part 2.4.9 states:

2.4.9 *Protection systems, including intelligent electronic devices (IEDs) and communication systems used for protection, should comply with applicable industry standards for utility grade protection service. Utility Grade Protection System Equipment are equipment that are suitable for protecting bulk power system elements, that are required to operate reliably, under harsh environments normally found at substations. Utility grade equipment should meet the applicable sections of all or some of the following types of industry standards, to ensure their suitability for such applications:*

- *IEEE C37.90.1-2012 (oscillatory surge and fast transient)*
- *IEEE C37.90.1-2012 (service conditions)*
- *IEC 60255-22-1, 2007 (1 MHz burst, i.e., oscillatory)*
- *IEC 61000-4-12, 2017 (oscillatory surge)*
- *IEC 61000-4-4, 2004 (EFT)*
- *IEC 60255-22-4, 2008 (EFT)*
- *IEEE C37.90.2-2004 (narrow-band radiation)*
- *IEC 60255-22-3, 2007 (narrow-band radiation)*
- *IEC 61000-4-3, 2010 (narrow-band radiation)*
- *IEEE 1613a, 2011 (communications networking devices in Electric Power Substations)*

Directory #4 - Appendix A Guideline and Recommendation for Bulk Power System Protection, Section 2.6:

NPCC stakeholders should consider amending section #2.6 to address the latency of IBR control systems and the demonstrated tendency of these systems to delay the return to service of the facility as demonstrated in NERC Disturbance reports.

Appendix A Guideline and Recommendation for Bulk Power System Protection, section #2.6 states:

2.6 *Operating Time*

Adequate time margin should be provided taking into account study inaccuracies, differences in equipment, and protection operating times. In cases where clearing times are deliberately extended, consideration should be given to the following:

- *Effect on system stability or reduction of stability margins.*
- *Possibility of causing or increasing damage to equipment and subsequent extended repair and/or outage time.*
- *Effect of disturbances on service to customers.*
- *Network configurations that impact the delivery or latency of GOOSE messages in one protection group should not momentarily or permanently affect the delivery or latency of GOOSE messages in the redundant protection group for the same element, unless studies demonstrate that the total clearing time including momentary interruption is acceptable.*

- *The reception and processing of a GOOSE message is time critical, specifically during events and relaying operations. The use of GOOSE messages for protection should be configured (dataset priority, how messages are published, VLANS, network configuration, etc.) such that the maximum clearing times as specified by Planning Studies are met.*

Directory #5 – Reserve

Although not specifically an IEEE-2800 related issue, NPCC Directory #5 was developed around the assumption that all of the generation on the NPCC Bulk Power System is synchronous. The development of the Directory #5 Criteria did not consider the extensive presence of IBR technology nor the intermittent nature of IBR power production.

Recent, NERC disturbance reports identified "near miss" events where the total loss of IBR technology resources approached the most severe level of generating reserves that were available on the day of the event.

Therefore, from a resource adequacy perspective, operating reserve policies may need to be redesigned to consider the need for an all hours-based reserve paradigm in the future.

Directory #8 – System Restoration

System restoration is not addressed in IEEE-2800. However, IBR technology is moving in the direction of Grid Forming inverters, rather than Grid Following inverters.

Although Grid Forming inverters are addressed in IEEE-2800, these technologies have not been widely deployed. However, Grid Forming inverters do support the resilience and reliability of the NPCC BPS and should be fully capable of participating in the restoration processes in accordance with Directory #8.

Accordingly, Directory #8 should be reviewed to consider the future availability of Grid Forming inverters as this technology is developed and guidance regarding how to restore the system from Grid Forming inverters evolves. The elimination of legacy synchronized machines used for black start capability generation due to decarbonization policies may create within certain NPCC Areas the need to rely on Grid Forming IBR's for black start and system restoration and these facilities should be compliant with the provisions of IEEE-2800.

Directory # 11 – Disturbance Monitoring Equipment Criteria

Where large penetration of non-compliant IEEE-2800 IBRs exist, Directory #11 should be reviewed to determine whether additional and specific Disturbance Monitoring criteria associated with IBR's is required.

Conclusion – Next Steps

The intent of this report is to initiate a dialogue among NPCC Full Members to consider the performance requirements of IBRs and the necessary changes to implement IEEE-2800 in accordance with the guidance provided by the NPCC Board of Directors within the 2023 Corporate Goals.

In some instances, the report also examines the implications of non-IEEE-2800 compliant IBR facilities on reliability within the region. However, as decarbonization transforms the BPS, it is prudent to consider the IEEE-2800 technical requirements and the available NERC guidance on IBRs during all interconnection assessments.

Although, the existing criteria may be adequate to allow an NPCC Full Member serving as the AGIR the latitude to include the provisions of IEEE-2800 in its specific interconnection review and model verification processes, more specific language including citations to IEEE-2800 within the Criteria should be considered since IBR technology was not widely utilized when the existing Criteria was developed.

Accordingly, the recommended next steps for NPCC Full Members are as follows:

(1) The RSC and RCC to review this report and provide comment. Specifically, comments are requested on whether the report provides the necessary guidance to the responsible NPCC Task Forces on the implications of incorporating the provisions of IEEE-2800 into the applicable Criteria when reviewing each Directory.
(2) After consideration of comments, a final report will be posted on the NPCC website and available to each NPCC Task Forces having authority over the respective Directories.

2023 REGIONAL STANDARDS COMMITTEE

Chairman:

Gerry Dunbar
Director – Reliability Standards & Criteria
Northeast Power Coordinating Council, Inc.
Tel. (212) 840-1070
Email: gdunbar@npcc.org

Co-Vice Chairman:

Chantal Mazza
Reliability Advisor
2 Complexe Desjardins, 13th floor, East Tower
Montréal, Québec, Canada H5B 1H7
Tel. (514) 879-4100 Ext. 5499
Email: mazza.chantal@hydro.qc.ca

Co-Vice Chairman:

Michael Jones
Manager, Reliability Standards and Policy
National Grid
40 Sylvan Road
Waltham, Massachusetts 02451
Tel. (781) 907-2404
Email: michael.jones@nationalgrid.com

Sector 1 - Transmission Owners

Hydro One Networks, Inc.

Primary
Emma Halilovic
Senior Manager – Reliability Standards Readiness & Strategy
Tel. (647) 407-7042
Email: Emma.Halilovic@HydroOne.com

Alternate
Alain Mukama
Senior Network Management Engineer – Reliability Standards & Regulation
Tel. (416)-574-1227
Email: alain.mukama@hydroone.com

Consolidated Edison Company of New York, Inc.

Primary
Deidre Altobell
Chief Engineer, Transmission Planning
4 Irving Place
New York, NY 10003
Tel. (212) 460-3968
Fax (212) 529-1130
Email: altobelld@coned.com

Alternate
Martin Paszek
Manager, System Performance
Tel. (212) 460-6415
Fax (212) 529-1130
Email: paszekm@coned.com

National Grid

Primary
John Hastings
Lead Analyst, Transmission Control Center – NY
7437 Henry Clay Blvd HCB-3
Liverpool, NY 13088
National Grid, US
Tel. (315) 460-4139
Email: John.Hastings2@nationalgrid.com

Alternate

New Brunswick Power Corporation

Primary
Erin Wilson
IT Specialist, Corporate Compliance
Tel. (506) 429-3074
Email: EWilson@NBPower.com

Alternate
Fon Hiew
Senior Engineer, Compliance
Tel. (506) 470-1933
Email: FHiew@nbpower.com

The United Illuminating Company

Primary
Michele Tondalo
Lead Analyst – NERC Compliance (O&P)
180 Marsh Hill Road
Orange, Connecticut 06477
Tel. (203) 499-2542
Email: Michele.Tondalo@uinet.com

Alternate
Michele Shafer
Lead Analyst – NERC Compliance
18 Link Dr.
Binghamton, New York 13904
Tel. (585) 484-6453
Cell. (607) 624-5984
Email: mmshafer@nyseg.com

Hydro-Quebec

Primary
Chantal Mazza
Reliability Advisor
2 Complexe Desjardins, 13th floor, East Tower
Montréal, Québec, Canada H5B 1H7
Tel. (514) 879-4100 Ext. 5499
Email: mazza.chantal@hydro.qc.ca

Alternate
Junji Yamaguchi
Manager - Reliability Standards and Operating Procedures
2 Complexe Desjardins, 13th floor, East Tower
Montreal, Québec, Canada H5B 1H7
Tel. (514) 289-2211 Ext. 2667
Email: Yamaguchi.junji@hydro.qc.ca

Orange & Rockland Utilities, Inc.

Primary
Stephanie Ullah-Mazzuca
Program Manager – NERC Compliance
1 Blue Hill Plaza
Pearl River, NY 10965
Tel. (845) 577-3796
Email: mazzucas@oru.com

Alternate
Susmit Patel
Section Manager – Substation & Transmission Engineering
Orange and Rockland Utilities Inc.
390 West Route 59
Spring Valley, NY 10977
845-577-3203
Email: patels@oru.com

Eversource Energy

Primary
Joshua London
Associate Engineer – Reliability Compliance
Eversource Energy
107 Selden Street
Berlin, CT
Cell: (774) 281-3221
Email: joshua.london@eversource.com

Alternate
Christopher O'Brien
Manager, Reliability Compliance
Office: 603.634.2702
Mobile: 603.361.2912
Christopher.OBrien@eversource.com

Central Hudson Gas & Electric

Primary
Michael Ridolfino
Director – Reliability Compliance
Office: (845) 486-5674
Cell: (845) 750-0896
Email: mridolfino@cenhud.com

Alternate
Damian Interrante
Reliability Compliance Analyst
Office: (845) 790-9020
Cell: (845) 443-0394
Email: dinterrante@cenhud.com

Vermont Electric Power Company, Inc.

Primary
Randy Buswell
NERC Compliance Manager
Tel. (802) 770-6264
Email: rbuswell@velco.com

Alternate
Deb Perkins
Compliance Analyst
Tel. (802) 770-6376
Email: dperkins@velco.com

Alternate
Sarah-Lynne Carrara
Compliance Analyst
Tel. (802) 770-6295
Email: scarrara@velco.com

Sector (2) - Reliability Coordinators

New York Independent System Operator

Primary
James (Jim) Grant
Senior Reliability Engineer
Tel. (518) 356-6128
Email: jgrant@nyiso.com

Alternate
Gregory A. Campoli
Manager, Reliability Compliance & Industry Affairs
Tel. (518) 356-6159
Email: gcampoli@nyiso.com

ISO New England, Inc.

Primary
Michael Courchesne
Principal Compliance Analyst
Tel. (413) 535-4346
Cell. (413) 265-3034
Email: mcourchesne@iso-ne.com

Alternate
Kathleen M. Goodman
Lead Compliance Analyst
Tel. (413) 535-4111
Email: kgoodman@iso-ne.com

Independent Electricity System Operator

Primary
Kurtis Chong
Manager, Compliance Assurance
Tel. (905) 301-7702
Email: Kurtis.Chong@ieso.ca

Alternate
Helen Lainis
Senior Regulatory Analyst
Tel. (905) 855-4106
Email: helen.lainis@ieso.ca

Hydro-Quebec

Primary
Nicolas Turcotte
Manager – Regulatory Affairs of the Reliability Coordinator
2 Complexe Desjardins, 13th floor, East Tower
Montréal, Québec, Canada H5B 1H7
Tel. (514) 879-4100 Ext : 5182
Email: turcotte.nicolas@hydro.qc.ca

Alternate
Stéphane Desbiens
Director – Reliability Standards & Regulatory Compliance
2 Complexe Desjardins, 13th floor, East Tower
Montreal, Québec, Canada H5B 1H7
Tel. (514) 289-4435
Email: Desbiens.Stephane@hydro.qc.ca

New Brunswick Power Corporation

Primary
Jeffrey Streifling
Senior Engineer, Compliance
Tel. (506) 458-4677
Cell. (506)259-5470
Email: JStreifling@nbpower.com

Alternate
Nurul Abser
Manager, Compliance
Tel. (506) 458-3964
Email: NAbser@nbpower.com

Sector (3) - Transmission Dependent Utilities ("TDUs"); Distribution Companies and Load-Serving Entities ("LSEs")

Consolidated Edison Company of New York, Inc.

Primary
Dermot Smyth
Senior Engineer
Tel. (212) 460-4093
Fax (212) 529-1130
Email: smythd@coned.com

Alternate
Lincoln Burton
Senior Engineer
Tel. (646) 660-3899
Fax (212) 529-1130
Email: burtonl@coned.com

National Grid

Primary
Michael Jones
Manager, Reliability Standards and Policy
40 Sylvan Road
Waltham, Massachusetts 02451
Tel. (781) 907-2404
Email: michael.jones@nationalgrid.com

Alternate

Orange & Rockland Utilities, Inc.

Primary
David Burke
Senior Specialist - Compliance
Tel. (845) 577-2841
Email: burkeda@oru.com

Alternate
Siobhan Keane - Revie
Project Specialist
Substation and Transmission Engineering
Tel. (845) 558-5438
Email: revies@oru.com

Sector (4) - Generator Owners

Consolidated Edison Company of New York, Inc.

Primary
Peter Yost
Manager, Standards & Compliance
Tel. (212) 460-2889
Fax (212) 529-1130
Email: yostp@coned.com

Alternate
Michael Foley
Engineer
Fax (212) 529-1130
Email: foleymi@coned.com

New York Power Authority

Primary
Salvatore Spagnolo
Program Manager, Reliability Standards & Compliance
Tel. (914) 390-8224
Mob. (347) 992-7015
Email: Salvatore.Spagnolo@nypa.gov

Alternate
Libin Varghese
Engineer, Reliability Standards & Compliance
Tel. (914) 390-8029
Mob. (845) 502-5888
Email: libin.varghese@nypa.gov

Bruce Power Limited Partnership

Primary
Bendong Sun
Tel. (519) 386-6973
Email: bendong.sun@brucepower.com

Alternate
Abbas Munir
Tel. (519) 386-2487
Email: abbas.munir@brucepower.com

Dominion Energy Services, Inc.

Primary
Sean Bodkin
NERC Compliance Policy Manager
Dominion Energy Services, Inc.
Tel. (804) 771-8429, tie line 8-786-8429
Cell: (804) 292-5721
Email: Sean.Bodkin@dominionenergy.com

Alternate
Connie Lowe
Regulatory and Market Policy Manager
Dominion Energy Services, Inc.
Tel. (804) 771-4447, tie 8-736-4447
Cell: 804-239-3201
Email: connie.lowe@dominionenergy.com

Ontario Power Generation, Inc.

Primary
David Kwan
Senior Manager, Reliability Compliance
Tel. (416) 592-6369
Email: david.kwan@opg.com

Alternate
Doug Preston
Senior Manager, Reliability Compliance
Tel. (905) 391-2765
Email: christopher.moir@opg.com

Alternate
Constantin Chitescu
Regulatory Analyst
Tel. (416) 592-6055
Email: constantin.chitescu@opg.com

NextEra Energy, LLC

Primary
Silvia Parada Mitchell
Senior Director, Reliability Standards & Compliance
Tel. (561) 904-3767
Email: silvia.parada.mitchell@fpl.com

Alternate
Summer Esquerre
Director Reliability Standards & Compliance
Tel. (561) 904-3765
Email: summer.esquerre@fpl.com

Entergy Services, Inc

Primary
Glen Smith
NERC Compliance
Entergy Services, Inc
440 Hamilton Avenue
White Plains, NY 10601
914-272-3513
Email: gsmith@entergy.com

Alternate

PSEG

Primary
Sean Cavote
Director NERC Compliance
PSEG Law Department
80 Park Plaza, P3
Newark, NJ 07102-4194
973-430-5310
Email: sean.cavote@pseg.com

Alternate
Tim Kucey
Manager NERC Compliance
80 Park Plaza, P3
Newark, NJ 07102-4194
908-412-3078
Email: Timothy.Kucey@PSEG.com

Sector (5) - Marketers, Brokers and Aggregators

Consolidated Edison Company of New York, Inc.

Primary
Jason Chandler
Engineer, NERC Reliability Compliance Section
4 Irving Place, New York, NY 10003
Tel. (212) 614-3547
Fax (212) 529-1130
Email: chandlerj@coned.com

Alternate
Qinling Zheng
Engineer
Tel. (212) 460-2790
Fax (212) 529-1130
Email: zhengq@ConEd.com

Utility Services, Inc.

Primary
Tracy MacNicoll
Manager of Technical Services, Operations and Planning Standards
Tel. (802) 241-1481
Email: Tracy.MacNicoll@utilitysvcs.com

Alternate
Devon Tremont
Executive Vice President of Technical Services
Tel. (802) 241-1489
Cell: (802) 393-3665
Email: Devon.Tremont@utilitysvcs.com

Sector (6) – State and Provincial Regulatory and/or Governmental Authorities

New York Power Authority

Primary
Shivaz Chopra
Director, Reliability Standards & Compliance
Tel. (914) 681-6828
Tel. (914) 391-6839
Email: shivaz.chopra@nypa.gov

Alternate
Zahid Qayyum
RSC Program Manager II
Tel. (914) 539-5092
Email: Zahid.Qayyum@nypa.gov

New York State Department of Public Service

Primary	Alternate
Vijay Puran Utility Supervisor, Electric Safety and Reliability Tel. (518) 486-5948 Email: vijay.puran@dps.ny.gov	Jerry Ancona Utility Supervisor, Electric Safety and Reliability Tel. (315) 448-7300 Email: Jerry.Ancona@dps.ny.gov

Sector 7 – Sub-Regional Reliability Councils, Customers and Other Regional Entities and Interested Entities

New York State Reliability Council, LLC

Primary	Alternate
Wes Yeomans Tel. (518) 813-3064 Email: Foosball1961@live.com	

Independent

Primary	Alternate
David Kiguel Independent Consultant Toronto, Canada Email: David.kiguel@outlook.com	

AESI, Inc.

Primary	Alternate
Joel Charlebois Vice President, Regulatory Compliance Tel. (770) 870-1630 x 236 Cell: (718) 419-4012 Email: JoelC@aesi-inc.com	